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April 9, 2014

Mr. Murat K. Mustafayev
Managing Director
Geology and Development
JSC KazMunaiGas EP
17, Kabanbai Ave.
Left Bank of Ishim River
Astana, 010000
Republic of Kazakhstan

Re: JSC KazMunaiGas EP
Reserves and Resources
As of December 31, 2013

Dear Mr. Mustafayev:

At your request, Miller and Lents, Ltd. (MLL) estimated the net liquids and gas reserves and future net revenues as of December 31, 2013 attributable to JSC KazMunaiGas EP (KMG EP) in certain oil and gas fields. Liquids include oil, condensate, and natural gas liquids (NGLs). The properties evaluated are located in the Republic of Kazakhstan. In addition, we estimated the net oil and gas resources as of December 31, 2013 attributable to KMG EP.

Our reserves evaluations were performed using the prices and expenses provided by KMG EP. The aggregate results of our evaluations as of December 31, 2013 for KMG EP are summarized below:

Total Company

	Net Reserves				Future Net Revenues	
Reserves Category	**Liquids, MMBbls.**	**Liquids, MMTonnes**	**Gas, Bcf**	**Gas, Bcm**	**Undiscounted, MM$**	**Discounted at 10% Per Year, MM$**
Proved Developed Producing	625.0	85.4	41.5	1.2	13,762.2	7,700.4
Proved Developed Nonproducing	83.4	11.3	0.0	0.0	2,609.9	917.7
Proved Undeveloped	194.1	25.4	291.2	8.2	4,642.5	1,275.2
Other Capital					-5,415.7	-2,703.6
Total Proved	**902.4**	**122.1**	**332.7**	**9.4**	**15,598.9**	**7,189.8**
Probable	198.3	26.7	134.3	3.8	6,117.9	1,499.4
Possible	248.0	33.9	29.0	0.8	6,502.0	1,575.4

Definitions

The reserves and resources reported herein conform to the standards of the Petroleum Resources Management System (PRMS), which was prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE). The document (SPE-PRMS) was reviewed and jointly sponsored by the World Petroleum Council, the American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers. Definitions from the SPE-PRMS are included in the Appendix. Net reserves and resources are attributed to the interests of KMG EP.

The mineral extraction taxes and rent taxes with respect to crude oil, condensate, natural gas and NGLs used in our evaluation are based on tax rate schedules prescribed by current Kazakhstan tax regulations. The schedules for mineral extraction taxes are generally based on annual production with different tax rates for volumes sold domestically and internationally. The schedules for rent taxes are generally based on international prices and are only applied to liquids volumes sold internationally.

The mineral extraction tax and rent tax are a deduction from gross revenues in determining net revenues, but are not a deduction from gross reserves in determining net reserves. As instructed by KMG EP, the interest used in the reserves evaluation of the KMG EP fields is 100 percent, with the exception of the Rozhkovskoye gas field where the interest used is 50 percent.

Future net revenues as used herein are defined as the total gross revenues less mineral extraction taxes, rent taxes, operating costs, and capital expenditures. The total gross revenue is the total revenue received by KMG EP after deduction of losses and tolling, transportation costs, export and customs duties, and value added tax. The future net revenues for total proved reserves include deductions for other capital that are not included in the individual proved categories. Future net revenues do not include deductions for taxes on net profit.

Reserves for all categories are considered economic for development if undiscounted future net revenues are positive.

Estimates of future net revenues and discounted future net revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves.

Well counts, as reported in the various economic output tables, represent counts of existing or newly drilled wells as appropriate for the reserves category. The well counts also include well work in existing wells. Thus, a single well bore may be counted more than once in the total well count.

Economic Considerations

The oil prices employed in the computations of gross revenues were provided by KMG EP. A 34-year schedule of prices was used in our evaluations. Beyond that date, prices were held constant. KMG EP provided MLL with the proportion of the volumes to be sold to the international and domestic markets. The prices for OMG and EMG were used to calculate weighted average prices, mineral extraction taxes and rent taxes.

The condensate, gas and NGL prices employed in the computations of gross revenues for the Rozhkovskoye gas field were provided by KMG EP. KMG EP provided MLL with the proportion of the condensate volumes to be sold to the international and domestic markets. The gas will be sold on the domestic market and the NGL will be sold to the international market. The prices for the Rozhkovskoye gas field were used to calculate weighted average prices, mineral extraction taxes and rent taxes.

The condensate, gas and NGL prices employed in the computations of gross revenues for the five gas fields were provided by KMG EP. Condensate volumes represent the combination of the pentane-hexane fraction (PGF) and fuel oil volumes. KMG EP provided MLL with the proportion of the condensate (PGF+fuel oil), gas and NGL volumes to be sold to the international and domestic markets. The prices for the five gas fields were used to calculate weighted average prices, mineral extraction taxes and rent taxes.

The operating expenses employed in estimating future net revenues for the oil fields are based on forecasted expenses provided by KMG EP. In estimating the operating costs, MLL deducted total depreciation and mineral extraction taxes. We allocated the operating expenses to the number of active completions on a per-completion basis and to the oil production rates on a per-barrel basis. We assumed that the number of active completions for the large waterfloods would decline to approximately one-half the fully developed count as the field declines in production and approaches the economic limit.

The operating expenses employed in estimating future net revenues for the five gas fields are based on forecasted expenses provided by KMG EP. In estimating the operating costs, MLL deducted total depreciation and mineral extraction taxes. We allocated the operating expenses to the number of active completions on a per-completion basis and to the gas production rates on a per-Mcf basis. We assumed that the number of active completions for the large gas reservoirs would decline to approximately one-half the fully developed count as the field declines in production and approaches the economic limit.

The operating expenses employed in estimating future net revenues for the Rozhkovskoye gas field were provided by KMG EP and are based on KMG EP's forecasted expenses for the field. These operating costs do not include depreciation and mineral extraction taxes.

Future gross capital investments for drilling and completing new wells and for well work in existing wells were provided by KMG EP. Forecasts of other capital investments, such as surface facilities and pipelines, were also provided by KMG EP.

Reserves Considerations

Reserves were estimated using standard geologic and engineering methods generally accepted by the petroleum industry. Volumes of oil and gas originally in place were calculated from structure and isopach maps, representative values for porosity and water saturation, and representative values of fluid properties. Estimates of recovery factors were derived from estimates of ultimate recovery and in-place volumes. Reserves were calculated by subtracting any historical production from the ultimate recovery, and further assigning the volumes to the appropriate reserves category.

The proved developed producing reserves and production forecasts for the majority of the reservoirs were estimated by rate versus time production decline extrapolations. For some reservoirs with insufficient performance history to establish trends, we estimated future production based on volumetric calculations or by analogy with other reservoirs having similar rock and fluid characteristics. Production declines were extrapolated to economic limits based on operating cost and product price data. Extrapolations of future performance are based, whenever possible, upon the average performance trend of active wells during periods of stable field activity.

The estimated proved developed nonproducing reserves can be produced from existing well bores but require capital costs for well work. The estimates of reserves and producing rates for the various types of well work were based on volumetric calculations and analogies with other wells that commercially produce the same fields.

The estimated proved undeveloped reserves require significant capital expenditures, such as well costs for development drilling and completion. The proved undeveloped reserves are expected to be produced from undeveloped portions of known reservoirs that have been adequately defined by wells. Reserves estimates were based upon volumetric calculations and the performance of analogous reservoirs. Producing rates are based upon analogy.

The estimated probable and possible reserves include the development of undeveloped portions of the fields and require significant capital expenditures. As new wells are drilled, portions of these probable and possible reserves quantities will be either upgraded to a higher reserves category or dropped entirely. The estimated probable reserves are expected to be produced from undeveloped portions of known reservoirs not adequately defined to be classified as proved.

The estimated possible reserves are expected to be produced from undeveloped portions of known reservoirs where (1) the reservoir is thin and uncertain to be developed or (2) where subsurface control is limited. Estimates of reserves for undeveloped portions of known reservoirs were estimated by volumetric methods.

Additional probable and possible oil reserves were assigned to certain producing reservoirs under the assumption that performance may exceed what is indicated by the rate versus time production projections. The probable and possible reserves projections were based on extrapolations of the water-oil ratio versus cumulative production performance trends for these reservoirs. These unproved reserves are based on performance and not on further development of undeveloped areas of the field.

Reserves estimates from volumetric calculations and analogies are often less certain than reserves estimates based on well performance obtained over a period during which a substantial portion of the reserves were produced.

No net gas reserves are attributed to the KMG EP oil fields because no revenues are derived from produced gas.

Contingent Resources

Contingent resources are defined by the SPE-PRMS as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects not currently considered to be commercially recoverable due to one or more contingencies.

Included in contingent resources are the volumes associated with well work evaluated by MLL that are uneconomic at current economic conditions.

A summary of the estimated contingent resources is shown in the table below:

Contingent Resources
Technically Recoverable

1C		2C		3C	
Net Oil, MMBbls.	Net Oil, MMTonnes	Net Oil, MMBbls.	Net Oil, MMTonnes	Net Oil, MMBbls.	Net Oil, MMTonnes
19.1	2.6	29.6	4.0	43.0	5.8

Prospective Resources

At the request of KMG EP, MLL estimated the prospective resources for seven licenses located in the North Caspian Basin.

Prospective resources are those quantities of petroleum, estimated as of a given date, to be potentially recoverable from an undiscovered accumulation by the application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Summary results for the 25 prospects evaluated by MLL are included in Attachment 1. The prospect hydrocarbon volumes reported in Attachment 1 are gross volumes which were determined probabilistically and are adjusted for commercial risk. Commercial risk is the chance of commerciality (Pc) and is the product of the chance of discovery (Pg), and the chance of development.

Five geologic risk factors were evaluated for each prospect within the licenses: source, seal, reservoir, timing/migration, and closure. The chance of discovery (Pg) is assessed based on the chance that all necessary components (reservoir, closure, seal, source, and timing) for a hydrocarbon accumulation are present and effective. The discovery is judged successful if the well(s) have penetrated a hydrocarbon accumulation(s) with sufficient volume to flow to the surface at a measurable rate and justify completion. Since these five chance factors are independent and all five must be present and effective for a successful outcome, the overall Pg is calculated as the product of the five factors. For example, if all five chance factors are judged to have a 50 percent chance of success, the result for the prospect would be a chance of discovery of 3.125 percent.

Given that a discovery is made, the full distribution of the range of uncertainty in potentially recoverable hydrocarbons will include some outcomes that are below the economic threshold for a commercially viable project. The probability of being above that economic threshold is used to define the chance of development. Therefore, the chance of commerciality (Pc) is calculated by multiplying the chance of discovery (Pg) by the chance of development. The distribution of potential outcomes is then recomputed for the "success case" or for a discovery that is larger than the economic threshold. The resulting chance of commerciality (Pc) is then multiplied by the mean value from the "success case" resource distribution to determine the risked mean resource value.

The prospective resource volumes shown herein were estimated by probabilistic methods using ranges of parameter values for reservoir volume, porosity, oil and gas saturation, pressure, temperature, density, oil and gas composition, and recovery factor. The ranges of reservoir volume employed for the probabilistic estimates were based on seismic depth structure maps prepared by KMG EP and reviewed by MLL. The other reservoir and fluid parameter values were based on data supplied by KMG EP, and the ranges of parameter values were estimated using ranges found in analogous fields in the area. For each prospect, a low estimate (equivalent to the P90 probabilistic value), a best estimate (equivalent to the P50 probabilistic value), and a high estimate (equivalent to the P10 probabilistic value) of unrisked prospective resources were estimated by MLL. For prospects with multiple reservoirs, resource estimates were calculated for individual reservoirs and then combined using probabilistic methods to obtain a total for the prospect.

It is important to note that the probability of finding hydrocarbon volumes that equal or exceed the mean volume cited herein for a prospect must consider not only the Pg for the prospect but also where the calculated mean value falls on the probabilistic distribution of possible outcomes for that prospect. However, if it is assumed that the calculated mean volumes and values are appropriate representations of their probabilistic distributions, MLL believes the approach described above gives a reasonable expected value quantification for each prospect. Arithmetic addition of results for each prospect at a specific probabilistic value (e.g., P10) does not give a correct probabilistic result for the aggregate except at the Mean Estimate.

Temir Block

KMG EP acquired the Temir Block in 2010 under Contract No. 3578 for an initial term of six years. The contract carries a right to extend the exploration period until 2019.

The Temir Block is located onshore Kazakhstan along the eastern margin of the Precaspian Basin. The license is about 240 kilometers south of the city of Aktobe and covers an area of approximately 3,854 square kilometers. A north-south running pipeline crosses the western half of the block.

Exploration on the block has been disappointing despite being in regional proximity to such fields as Kenkiyak, Zhanazhol, and Alibekmola. To date, a total of 24 wells have been drilled within the license into both the sub-salt and post-salt sections without a commercial discovery. Underlying much of the block is the north-south-trending Temir Platform, an uplifted basement block capped by Carboniferous carbonates and patch reefs that have been the target of the sub-salt drilling.

Subsurface mapping on the block has been facilitated by the use of a 2D seismic grid that was acquired in 2011. This widely-spaced grid has helped to identify four prospects in the sub-salt section (prospects I, II, III, and IV). Given the drilling history and quality of the seismic, significant risk exists for all four prospects. The risks are mainly tied to migration, mapping confidence, and to a smaller measure, reservoir. Closure is an added risk on Prospect II since it does not have full seismic coverage.

Zharkamys East-1 Block

The Zharkamys East-1 Block was acquired by KMG EP in December, 2010 and is governed by Subsoil Exploration and Production Contract No. 2193 which has been extended to the end of 2014.

The Zharkamys East-1 Block covers an area of approximately 1,190 square kilometers and is located in the Pre-Ural plateau in the Aktyubinsk region of Kazakhstan. The block lies within the Zharkamys-Temir Petroleum District that includes Akzhar, East Akzhar, Karatobe, South Karatobe, Loktybay, and Zhanatan fields.

The Karatobe Prospect is a subsalt closure delineated by 2D seismic with potential P3 Middle Devonian sandstone reservoirs trapped on the high side of a vertical fault with a vertical displacement of approximately 250 meters. The prospective closure is mapped at a depth of 6,300 meters subsea and covers a mean area of 3.5 square kilometers. The primary geologic risks are reservoir, closure, and containment risks.

Uzen-Karamandybas Block

KMG EP acquired the Uzen-Karamandybas Block in 2010 under Contract No. 3579. The exploration block encompasses a number of mature oil and gas fields including the large Uzen Field. Although several of the fields are covered by 3D seismic, most of the prospects were generated using older 2D seismic data. The exploration license expires in 2016.

The Uzen-Karamandybas Block is the most southern of the KMG EP exploration licenses and lies within the South Mangyshlak Sub-basin. The dominant petroleum reserves of the basin are in Middle Jurassic sandstones in structural traps. Minor reserves are in fractured Triassic carbonates and clastics. Lower Cretaceous sandstones and fractured basement granites also produce locally. All of the oils have similar chemical characteristics. They are of medium gravity (31-38 degree API), and have high paraffin and low sulfur content.

Most oil and gas fields and discovered reserves are found on the Zhetybay step, a gently south dipping structural terrace north of the deeper Mangyshlak Basin. Originally a rift zone, the Zhetybay step was structurally inverted at the end of the Triassic by intense compression into a series of elongated, northwest-southeast-trending anticlines that form most of the traps.

Source rocks for the basin are generally considered to be basinal Middle Triassic shales. The only regional seal of high quality is the Upper Jurassic transgressive marine shale and carbonate sequence. Although the Upper Jurassic seal is greater than 500 meters thick in the deepest parts of the Mangyshlak Basin, it thins to less than 100 meters in Uzen Field where it helps trap an oil column more than 300 meters. The Triassic and deeper sections do not appear to contain regional seals and wells drilled into the Triassic section in the Uzen Field did not produce at a commercial rate.

The North West Tenge Prospect is mapped as a structural closure on a series of Triassic reflectors bounded by high-angle normal fault to the north. The prospect appears to be more of a stratigraphic trap beneath a regional Jurassic angular unconformity. Principal risks relate to reservoir, as no wells have penetrated the Triassic in this part of the basin, and to the likely absence of a top seal.

The Uzen-Karamandybas Paleozoic Prospect prospect is mapped as a non-faulted anticlinal closure on the top of the Paleozoic section. A portion of the structural crest lies outside the Uzen-Karymandybas License. Principal risks are closure and the potential absence of a top seal.

Taysoygan Block

The Taysoygan Block license, which expires in 2035, includes both exploration and development phases. The exploration period has been extended through 2015.

The Taysoygan Block is the most centrally located of all the KMG EP licenses within the Precaspian Basin in an area referred to as South-Embin. The sub-salt section, normally targeted on the flanks of the basin, lies at depths in excess of eight kilometers on this block and has not been penetrated by drilling. The block comprises an area of 9,605 square kilometers and access to much of the area is restricted by the presence of a missile testing range. Prospectivity is limited to the post-salt section; notably the mixed clastic-carbonate Middle Triassic interval, which onlaps a number of salt domes on the block beneath a regional Lower Jurassic unconformity. Oil fields in the area include Kenbay, Zhylankabak, and Kozha South.

Originally mapped using 2D seismic data, the Bazhir East Prospect is located west of the Kondybai and Uaz fields, along the southern margin of the license, and is mapped as a single, north-south-trending feature with a south and north culmination. In 2011, KMG EP drilled the G-1 well to test the southern feature in a crestal position. The well was unsuccessful and reportedly tested water with an oil skim. Since then, KMG EP has re-mapped the Bazhir East Prospect using a newly acquired 86 square kilometer 3D survey. The primary risks to the Bazhir East Prospect are map reliability and closure, and secondary risks are reservoir presence and quality.

The Uaz #1 Prospect is located in the southeastern margin of the license and is a three way closure on the south side of a salt piercement. The primary risks are closure and reservoir presence.

Karaton-Sarkamys Block

The Karaton-Sarkamys license was awarded to KMG EP in 2010 by Contract No. 3577 and expires in 2016. Under terms of the license agreement, only exploration of the post-salt section is permitted.

The Karaton-Sarkamys Block is located in the southeast portion of the Precaspian Basin and covers an area of 2,642 square kilometers. A number of post-salt fields have been developed within the block as well as two sub-salt fields, Tengiz and Korolev. The post-salt fields range in size from 7 to 500 million barrels of oil-in-place, and are generally related to salt structures, either as onlap traps on salt flanks, fault traps, or four-way closures above salt. Reservoirs properties of Jurassic and Cretaceous sandstones that occur above salt domes can be excellent. The properties deteriorate somewhat for the more deeply buried Triassic and Upper Permian strata.

The S. Nurzhanov No.HC-B2 Prospect is situated in the southern part of the license and is mapped as an upthrown three way closure against a west-east normal fault. The S. Nurzhnov Field, located two kilometers to the south, produces from the main target horizons. The field and prospect are separated by an intervening graben. The principle risk is cross-fault containment.

The Dosmukhambetovskoye Prospect is situated in the south-central part of the license and is actually comprised of three separate fault traps along the eastern flank of the Dosmukhambetovskoye field, which produces from Cretaceous and Upper Jurassic sands in a four-way closure above salt. The main risks to the series of fault traps at Dosmukhambetovskoye are the ability of the faults to seal and the timing of trap formation relative to oil migration. For some of the deeper horizons mapping confidence near the salt face is also less certain. Those prospects having a component of independent four-way closure are considered to have less risk.

Karpovsky North Block

The Karpovsky North Block occupies an area of 1,669 square kilometers and is located along the narrow north margin of the Precaspian Basin near the border with Russia. Three thick carbonate intervals and their time equivalent clastics in the Upper Devonian-Lower Permain sub-salt and post-salt section are the principal drilling targets for this portion of the basin. Uplifted basement blocks, some overlain with carbonate buildups, and thrust structures comprise most of the productive structures on trend with the license. Nearby fields such as Karachanganak, Chinarevskoye, and Nepryakhinskoye produce mainly oil and gas-condensate. The exploration license is scheduled to expire at the end of 2014.

Five prospects, Melovaya, Orlovskaya Central, Orlovskaya South, Belosyrtovskaya and Pervosovetskaya, have been identified by KMG EP within the Karpovsky license. Melovaya and Orlovskaya are supported by 3D seismic and mapped as closed four-way structures. The primary targets are Melovaya are Devonian clastics that have previously been found to be productive in the area (Nepryakhinskoye Field). In Orlovskaya Central and Orlovskaya South, the principal target is a carbonate of Late Devonian to Early Mississippian age. Thrust faulting purportedly occurs north of the Melovaya Prospect, an observation consistent with the structural style common to this area.

The Belosyrtovskaya Prospect is mapped as a four way closure at the Carboniferous horizon. The prospective closure is limited downdip by the previously drilled, non-productive No. 2 Belosyrtovskaya well. The prospective horizons include Carboniferous and Devonian sediments located updip of the No. 2 Belosyrtovskaya well. The principle risks for the Belosyrtovskaya Prospect are reservoir and closure.

The Pervosovetskaya Prospect is mapped as a three way closure on the downthrown side of a down-to-the-southeast fault. The prospective horizon is Middle Devonian in age. The principle risks are reservoir and cross fault seal.

Fyodorovsky Block

In 2011, KMG EP acquired the interests of Ural Oil & Gas LLP and, therefore, a 50 percent working interest in the Fyodorovsky Block. Current exploration partners include MOL Caspian Oil and Gas Limited and First International Oil Corporation with 27.5 and 22.5 percent working interests, respectively. The exploration license, which was originally issued in 2000 as Contract No. 486, expired in 2010 but has been extended to 2014. KMG EP and the Kazakhstan oil and gas ministry are currently discussing an extension to the exploration license.

The Fyodorovsky Block is located east of the Karpovsky license, in the area where the northern flank of the Precaspian Basin borders the southwestern extension of the Ural Mountain foldbelt. Structurally, the sub-salt section of the license is dominated by a series of northwest-southeast-trending basement highs and intervening lows. The core of the uplifts are Riphean (Precambrian) basement rocks.

On the flanks of the uplifts, Middle-Lower Devonian clastic and carbonate reservoirs occur as part of a transgressive shoreline wedge. This onlapping wedge thickens off structure and down the plunge of the basement highs, and is preserved beneath a regional Upper Devonian (Frasnian) angular unconformity. At the base of the wedge lie Lower Devonian (D1 horizon) sandstones, siltstones and shales ranging in thickness from 40 to 80 meters. Middle Devonian rocks present just below the Upper Devonian unconformity (P3 horizon) are comprised of carbonates and interbedded clastics, some of which produce locally. Younger lowstand clastics, deposited above the Upper Devonian unconformity, constitute one of the more prospective, but least explored plays on the block.

Seven prospects have been identified by KMG EP on the Fyodorovsky Block using 2D and 3D seismic. The Rubezhinskaya P3 Prospect is comprised of a preserved section of the Upper Devonian against a northwest-southeast-trending thrust fault as a footwall trap. This prospect is mapped on the regional Upper Devonian unconformity (P3) seismic event and is located immediately east of the RBZ-8 well. In the northwest part of the license is the Rubezhinskaya D1 Prospect, a similarly structured footwall prospect involving the deeper Lower Devonian (D1) clastic interval. The Zhaik Prospect is mapped as a combined anticlinal/three-way closure. The structure lies on the upthrown side of a east-west normal fault. The prospective horizons are Upper Devonian and Lower Carboniferous carbonates and clastics. The Rozhkovskaya Field West Structure is mapped as a three-way prospective closure on the downthrown side of west-east trending fault. The target horizons are Middle Devonian clastics.

Rozhkovskoye Field East Structure is a three-way closure on the upthrown side of a west-east trending normal fault. The target horizons are Middle Devonian clastics. The Januartevskaya Prospect is mapped as a three-way closure on the downthrown side of a west-east trending normal fault. The prospective horizons are Upper Devonian and Lower Carboniferous carbonates and clastics.

The Burlinskaya Prospect, lies along the Kazakhstan-Russian border. The structure is mapped as an anticlinal closure. The prospective horizons are Upper Devonian and Lower Carboniferous carbonates and clastics.

Geologic risks for the Fyodorovsky Block prospects mainly involve reservoir presence and quality, mapping confidence, and seal. The prospects rely on relatively small faults (two in the case of the Rubezhinskaya P3 Prospect) for lateral seal and both assume the presence of reservoir in a depositional environment that could have changed dramatically over short distances. Although seismic data quality for the sub-salt section is reasonably good, fault definition and continuity of mappable events are sometimes poor.

Other Considerations

None of the reserves volumes or the estimated future net revenues therefrom have been adjusted for uncertainty. None of the proved, probable, or possible reserves volumes, nor the revenues projected therefrom, should be combined with either of the other without adjustment for uncertainty.

Future costs of abandoning facilities and wells and any future costs of restoration of producing fields to satisfy environmental standards were not deducted from total revenues as such estimates are beyond the scope of this assignment.

In the forecasts of production and future net revenues, no provision was made for expiration of production licenses. KMG EP has represented to MLL that there is reasonable expectation their production licenses would be extended beyond their expiration dates to their economic lives.

In conducting this evaluation, we relied upon production histories; accounting and cost data; ownership; geological, geophysical, and engineering data; and drilling, recompletion, and workover schedules supplied by KMG EP. KMG EP represented that their field development plans provided to us to use in our evaluations are consistent with their business plan and have been approved by the management of KMG EP. These data were accepted as represented, as verification of such data and information was beyond the scope of this assignment.

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Mr. Murat K. Mustafayev
JSC KazMunaiGas EP

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgments and are subject to the inherent uncertainties associated with interpretation of geological, geophysical, and engineering information. These uncertainties include, but are not limited to, (1) the utilization of analogous or indirect data and (2) the application of professional judgments. Government policies and market conditions different from those employed in this study may cause (1) the total quantity of oil, natural gas liquids, or gas to be recovered, (2) actual production rates, (3) prices received, or (4) operating and capital costs to vary from those presented in this report. At this time, MLL is not aware of any regulations that would affect KMG EP's ability to recover the estimated reserves. Minor precision inconsistencies in subtotals may exist in the report due to truncation or rounding of aggregated values.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in KMG EP or any affiliate of KMG EP. Our compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and we have not performed other work that would affect our objectivity. Production of this report was supervised by an officer of the firm who is a professionally qualified and licensed Professional Engineer in the State of Texas with more than 30 years of relevant experience in the estimation, assessment, and evaluation of oil and gas reserves.

Yours very truly,

MILLER AND LENTS, LTD.
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Definitions and Guidelines for Petroleum Resources

Recoverable Resources Classes and Sub-Classes

Reserves

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

Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

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

Approved for Development. All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project 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.

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.

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 re-classification 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.

Reserves Category Definitions and Guidelines

Proved Reserves

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

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

The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contact, 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.

Reserves Status Definitions and Guidelines

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 recompletion 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.

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