TENGE JV

Competent Person's Report
Tenge Field - Kazakhstan

As of December 31, 2010

McDaniel & Associates Consultants Ltd.

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Tenge Field – Kazakhstan

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Prepared For:

Tenge JV LLP
Microdistrict 3/6
Zhanaozen City, 130200
Kazakhstan

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May 2011

TENGE JV

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May 5, 2011

Tenge JV LLP
Microdistrict 3/6
Zhanaozen City, 130200
Kazakhstan

Reference: **Tenge JV LLP**
Competent Persons Report as of December 31, 2010

Attention: Mr. Daniyar Mukushev, General Director

Dear Sir:

1 INTRODUCTION

Pursuant to your request we have prepared an evaluation of the crude oil and natural gas reserves and the net present values of these reserves for the interests of Tenge JV LLP ("Tenge JV") in Jurassic Zones 18, 21, 22 and 23 of the Tenge Field in Western Kazakhstan, as of December 31, 2010.

The future net revenues and net present values presented in this report were calculated using forecast prices and costs using McDaniel & Associates opinion of future crude oil and natural gas prices at January 1, 2011 and were presented in United States dollars.

The reserves estimates and future net revenue forecasts have been prepared in accordance with the 2007 SPE/WPC/AAPG/SPEE Petroleum Resource Management System. The format and content of this report follows the guidance set out in the June 2009 Note for Mining and Oil & Gas Companies published by the London Stock Exchange.

Standard industry practice for reserves evaluations in a country that does not have a history of production contract extensions past the contract expiry date (such as Kazakhstan) is to only assign reserves that are forecast to be produced up to the contract expiry date. The reserves presented in this report are those produced to the end of the contract but those reserves expected to be produced to the end of the field life are also presented in separate tables for illustrative purposes.

This evaluation was prepared during the period from March to May 2011 and was based on technical and financial data to the end of December 2010. Tenge JV has provided McDaniel & Associates with written representation to confirm the completeness and accuracy of the data provided and that no new data or information has been acquired between December 31, 2010 and the date of this report which might materially impact our opinions in this report.

2 CORPORATE SUMMARY

Tenge JV has an interest in the Tenge field in Kazakhstan as shown in Figure 1 below:

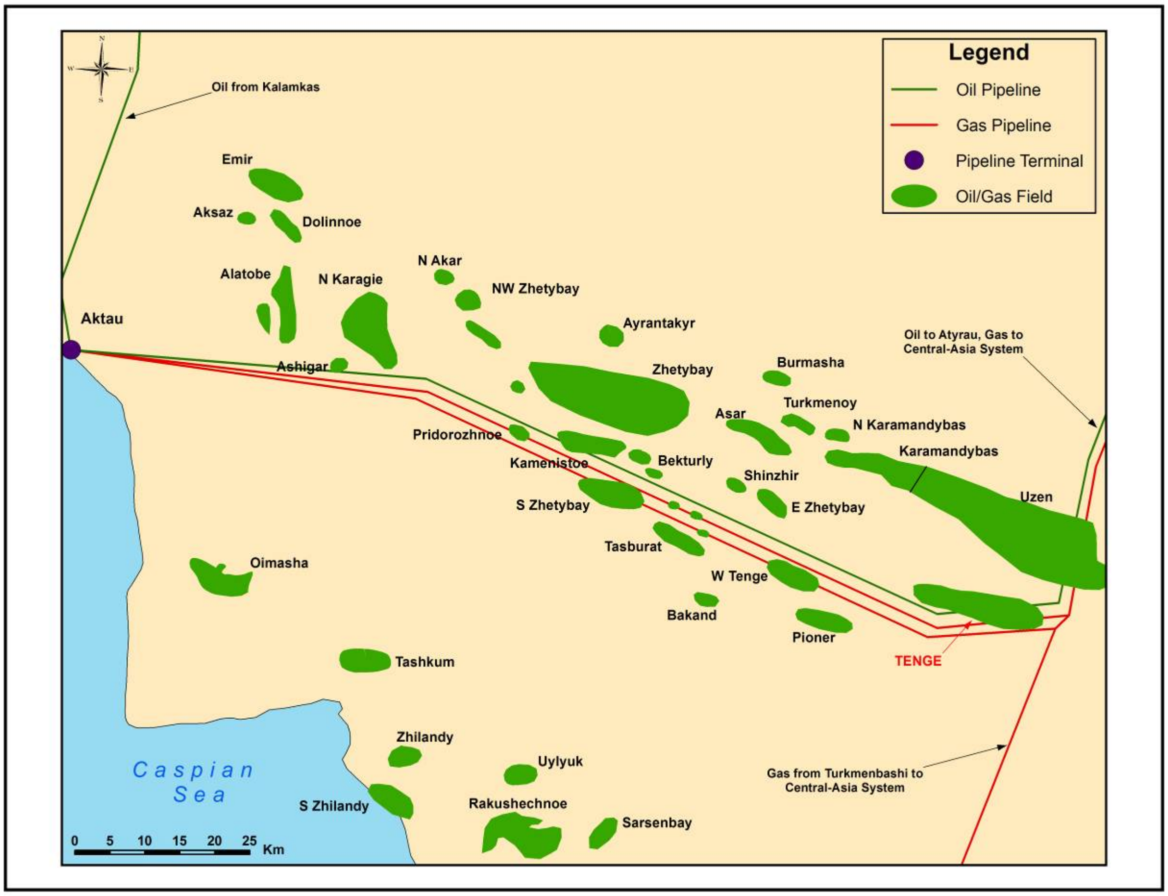

Figure 1 – Location Map for the Tenge Field in Kazakhstan

A summary of Tenge JV's ownership in the Tenge field is presented in Table 1 below.

Table 1 - Tenge JV Asset Summary

Oil & Gas Field	Country	Operating Company	Contract Type	Interest	Contract Expiry Date	Area (sq.km)
Tenge	Kazakhstan	Tenge JV	Production	100%	Sept 5, 2020	154

2.1 Reserves

Tenge JV's gross and net working interest share of the remaining crude oil and natural gas reserves, as of December 31, 2010 are presented in Table 2 below:

Table 2 - Tenge JV Crude Oil and Natural Gas Reserves Summary

Crude Oil and Natural Gas Reserves at December 31, 2010, Mbbl, MMcf (1)

	Proved Prod.	Proved Undev.	Total Proved	Probable	Total Proved plus Probable	Total Possible	Total Proved plus Probable plus Possible
Crude Oil							
Gross (2)	393	8,165	8,558	45,443	54,000	35,916	89,917
Net (3)	369	7,620	7,989	40,539	48,529	31,267	79,796
Natural Gas							
Gross (2)	-	-	-	209,267	209,267	126,047	335,313
Net (3)	-	-	-	188,340	188,340	113,442	301,782
Barrels of Oil Equiv. (4)							
Gross (2)	393	8,165	8,558	80,320	88,878	56,924	145,802
Net (3)	369	7,620	7,989	71,929	79,919	50,174	130,093

(1) Reserves are estimated to the end of the current contract (September 5, 2020).
(2) Gross reserves include Tenge JV's 100 percent working interest reserves before deductions of royalty.
(3) Net reserves include gross reserves after deduction of royalty.
(4) Based on a conversion of 6 thousand cubic feet of natural gas equal to 1 barrel of oil equivalent.

2.2 Net Present Values of the Reserves

The net present values of the reserves were based on future production and revenue analyses. Tenge JV's share of the net present values of the reserves were based on forecast prices and costs as of December 31, 2010 are presented in Table 3 below:

Table 3 – Tenge JV Net Present Value Summary

	Net Present Values at December 31, 2010 (1) (US$1000)				
			Discounted At		
	0%	5%	10%	15%	20%
Before Income Taxes (2) (3)					
Proved Producing Reserves	14,384	12,132	10,432	9,119	8,084
Proved Undeveloped Reserves	174,804	125,761	90,510	64,745	45,639
Total Proved Reserves	189,188	137,893	100,943	73,865	53,724
Probable Reserves	2,054,269	1,505,937	1,123,342	850,304	651,505
Total Proved + Probable Reserves	2,243,457	1,643,831	1,224,284	924,169	705,229
Possible Reserves	1,789,182	1,306,476	971,573	733,989	562,051
Total Proved + Probable + Possible Reserves	4,032,639	2,950,306	2,195,857	1,658,158	1,267,280
After Income Taxes (2) (3)					
Proved Producing Reserves	13,844	11,673	10,035	8,769	7,771
Proved Undeveloped Reserves	122,530	83,972	56,596	36,852	22,426
Total Proved Reserves	136,374	95,645	66,630	45,621	30,196
Probable Reserves	1,252,495	899,356	654,424	480,834	355,437
Total Proved + Probable Reserves	1,388,868	995,002	721,054	526,455	385,633
Possible Reserves	1,048,917	760,670	560,400	418,244	315,393
Total Proved + Probable + Possible Reserves	2,437,785	1,755,671	1,281,454	944,699	701,026

(1) Net present values are estimated to the end of the current contract (September 5, 2020).
(2) The net present values may not necessarily represent the fair market value of the reserves.
(3) The value of all wells and facilities are included in the net present value estimates

3 PROPERTY OVERVIEW

The Tenge field is located in the Mangistau region of Western Kazakhstan approximately 150 kilometers east of the city of Aktau as shown in Figure 1. The field is a large four way dip closed anticline structure measuring approximately twenty by three kilometers and is positioned immediately to the south of the large Uzen field.

The Tenge field was discovered in 1964 and has been developed as a gas field from five Jurassic intervals (zones 13 to 17) with production starting in 1970. Gas production from these intervals reached a maximum of 220 MMcfpd in 1974 before declining rapidly and for the last 10 years the field has produced less than 10 MMcfpd. The production is used to supply gas to the Uzen field and the local town of Zhanaozen, but the current economics are understood to be marginal. These shallow gas reservoirs were not included as part of this evaluation.

Below the depleted gas zones there are a number of additional Jurassic intervals which, unlike the shallower zones, also have oil bearing intervals in the form of oil rims. (The term oil rim is used in this report to denote an oil zone that is overlain by a gas cap and underlain by a water leg.) These intervals, which are located at depths below 1,600 meters subsea ("m ss"), are referred to as Zones 18, 21, 22 and 23 and are largely undeveloped and are the focus of this report.

The field has approximately 60 wells drilled to date. Nearly all the wells were drilled during the 1960's and 1970's. The wells that intersected the deeper oil bearing zones were often tested immediately after drilling with typical rates in the range of 10 to 300 bopd. The oil is light (36° API) and waxy which is typical of the area. The composition of the gas within the gas caps is predominantly methane (butane and heavier components amount to less than 1 mol percent) and does not contain hydrogen sulphide.

Whilst the original intention was probably to leave the deeper zones until the oil intervals could be properly exploited, there were five gas wells that were re-completed on the deeper gas caps. The most significant gas production was from zones 22 and 23 where four wells produced a total of 90 Bcf between 1972 and 1980 (approximately 30 percent of the original gas in place). As production from two of the re-completed wells was commingled with production from the shallower intervals (zones 14, 15 and 16), the production allocation is uncertain. It is not clear what the impact of this production has been on the associated oil intervals.

Since 2000 approximately seven of the old gas wells have been recompleted on the oil rims with somewhat mixed results. Only five wells have managed to sustain production and of the 890,000 bbl of oil produced to date 86 percent of this comes from two wells (TE-6 and TE-52) which are both producing within 200 meters of each other from the oil rim on zone 18. Initially these two wells each produced at rates over 200 bopd. Current production is around 260 bopd from the four producing wells. Oil from TE-6 and TE-52 is gathered at a small group station where the gas is separated and flared. The other wells, TE-2 and TE-58 both produce to a tank alongside each well which is open to the atmosphere to allow any gas to be vented. All the produced liquids are then trucked to the nearby Uzen processing facility (CPF) owned by

KazMunaiGas. Here any water is removed and the oil is treated to the specifications required by the KazTransOil operated pipeline which is linked to the main Atyrau-Samara system.

Whilst it was originally hoped that the deeper reservoirs could be developed at relatively low cost using the old gas wells it now appears, due to the state of these very old wells and the difficulty in re-completing wells to date, that new wells will be required to properly develop the field. In 2002 a new well was drilled (TE-235) to target the oil interval in zone 23, however, the results were somewhat disappointing. The resistivity measurements across the section where the oil should be present are very low suggesting either very low or no hydrocarbon saturation. The resistivity measurements across the section where the oil should be present are very low suggesting either very low or no hydrocarbon saturation. Operations at the well were suspended due, in part, to a change in ownership of the field. There is some concern that the earlier gas production on zones 22 and 23 may have affected the oil rim causing it to partly migrate into the gas cap. Due to this risk no oil reserves for an oil rim development in zones 22 and 23 have been assigned as part of this evaluation.

In February 2008 drilling of a new well, TE-467, close to wells TE-6 and TE-52 was started. Unfortunately, after a number of months the drilling had to be stopped prior to reaching the reservoir section due to problems with the rig and the drilling contractor. Tenge JV has plans to drill a number of new vertical wells around the field area to gather some much needed up to date data, particularly on the state of the oil bearing intervals in zones 22 and 23, the current reservoir pressures and to help improve the geological model. Tenge is also planning to drill some horizontal wells as ultimately the development of the oil rims will require the drilling of horizontal wells to minimize the risk of coning gas and/or water.

The exact development plans will depend on the results of further study work that Tenge JV intends to undertake. Through further integration of the existing subsurface well data and 3D seismic data (which shows some indications of channel like features) it is hoped to better understand the geometry of the reservoir and to characterize the channel systems.

Gas reserves have been assigned as part of this evaluation as the field is close to gas export pipelines and the gas market in Western Kazakhstan is to some degree established. Proved gas reserves have not been assigned as there is no gas contract in place for the gas in zones 18 to 23.

Further exploration potential may exist in the Triassic which lies below the existing Jurassic hydrocarbon bearing reservoirs. The Triassic represents a secondary target within the Mangyshlak area and five old wells in Tenge were drilled deep enough to encounter potential pay sections. Three of these wells (TE-51, TE-55, TE-58) are reported to have tested small amounts of oil, but they did not support flow to surface. The Triassic potential was not included as part of this evaluation.

4 OWNERSHIP AND CONTRACT TERMS

The licensing and contractual arrangements for the field are complex due to changes in the State sub-surface laws, a number of ownership changes and some legal disputes all of which have occurred since an original Tenge Joint Enterprise foundation agreement was signed in 1993 between MangistauMunaiGas (then fully owned by the State) and Anglo-Dutch a US company. Tenge JV has informed us that all the historical contractual and legal issues are currently resolved and that Tenge JV holds a 100 percent working interest in the Tenge Joint Enterprise.

The terms of the original sub-soil use license covering the field were revised in 2009 and the field is now required to pay taxes in line with the current Kazakh tax code. These include mineral extraction tax, export rent tax, property tax, corporation tax, excess profits tax and some other minor taxes. The sub-soil use license covering the field was registered on September 1, 1995 for a period of 25 years and is set to expire on September 5, 2020. There is a provision within the contract for a possible extension of between 5 and 15 years. The Ministry of Energy and Mineral Resources has written to Tenge JV outlining that any extension would need to be negotiated in 2018 two years before the current expiry.

The existing contract allows for the full development of all the hydrocarbon zones including zones 18, 21, 22 and 23. A technological scheme was originally approved for the field in 1997. In 2008 a revised technological scheme was approved based on drilling vertical and horizontal wells and providing pressure support through water injection.

A summary of the economic terms are presented in Table 10 of the Appendix.

5 RESERVES DEFINITIONS

The definitions employed in this evaluation conform to the 2007 Petroleum Resource Management System jointly published by the Society of Petroleum Engineers ("SPE"), World Petroleum Council ("WPC"), American Association of Petroleum Geology ("AAPG") and the Society of Petroleum Evaluation Engineers ("SPEE").

5.1 Resources

The term "resources" is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

The resources classification framework is summarized in Figure 2 and a summary of the definitions are given below.

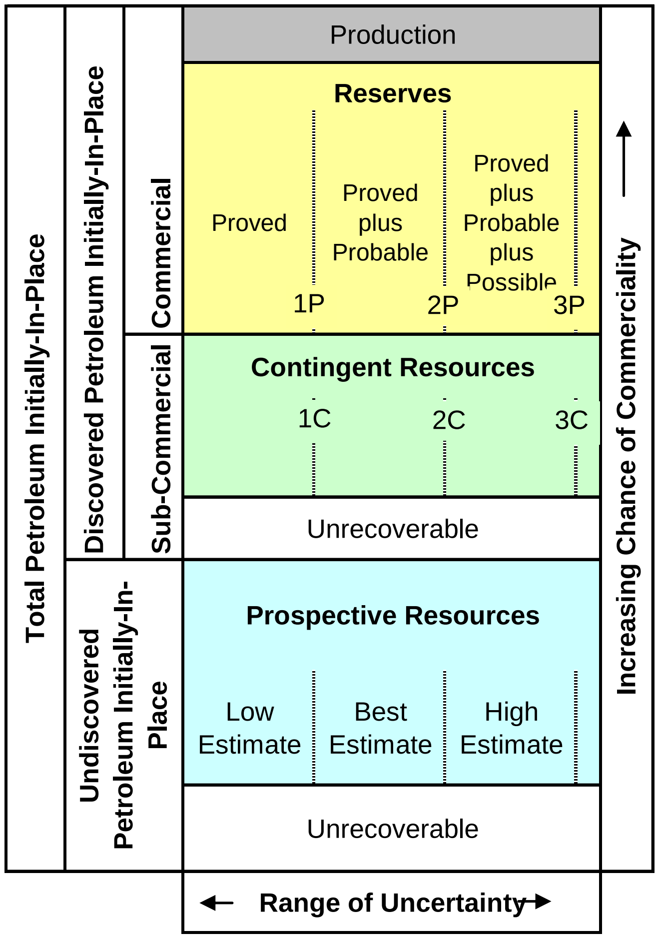

Figure 2 – Resource Classification Framework

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of Commerciality", that is, the chance that the project that will be developed and reach commercial producing status.

The quantities estimated to be initially-in-place are defined as Total Petroleum-initially-in-place, Discovered Petroleum-initially-in-place and Undiscovered Petroleum-initially-in-place, and the recoverable portions are defined separately as Reserves, Contingent Resources, and Prospective Resources. Reserves constitute a subset of resources, being those quantities that are discovered (i.e. in known accumulations), recoverable, commercial and remaining.

Reserves

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

The reserve classification system is covered in Section 5.3.

Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development 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.

Prospective Resources

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

5.2 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

There should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

There should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

There should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately.

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

5.3 Reserves Categories and Status

For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system.

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 percent probability that the quantities actually recovered will equal or exceed the estimate.

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 percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves

Possible Reserves are those additional Reserves which analysis of geoscience and engineering data suggest 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) Reserves, which is equivalent to the high estimate scenario. In this context, 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.

Reserves status categories define the development and producing status of wells and reservoirs.

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.

Undeveloped Reserves

Undeveloped Reserves are expected quantities expected to be recovered through future investments: (1) from new wells on undrilled acreage, (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.

5.4 Contingent Resource Categories

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. No specific terms are defined for incremental quantities within Contingent Resources.

5.5 Prospective Resource Categories

For Prospective Resources, the general cumulative terms low/best/high estimates apply. No specific terms are defined for incremental quantities within Prospective Resources.

6 SOURCE AND QUALITY OF DATA

All of the basic information employed in the preparation of this report was obtained from Tenge JV. McDaniel & Associates personnel visited Tenge JV's office in Almaty and Zhanaozen, Kazahstan to gather all available technical data and to review geological interpretations with Tenge JV's technical staff.

The data set comprised seismic data, original well data, production data, contractual data and financial data on operating costs, capital costs and crude oil pricing. The 3D seismic acquired in 2002 together with several seismic interpretation reports was provided. Well log data for forty wells that penetrated below zone 18 were provided in digital format. This log data typically comprises gamma ray, spontaneous potential, resistivity and a neutron porosity log. In addition two wells have a sonic log. The logs themselves provide insufficient data to reliably estimate porosity and water saturation and are mainly used as a net sand indicator. However, well TE-235 drilled in 2002 does have a complete set of modern logs.

A Moscow based institute, Central Geophysical Expedition ("CGE") has carried out a full reservoir modeling and petroleum engineering study of the field over the last two years including seismic interpretation, reservoir geocellular modeling and reservoir simulation. The top surfaces for the reservoir horizons generated as part of this study were used as the top structure maps for this evaluation.

A number of other reports were also provided including the 1967, 1968, and 2008 State Reserves Calculations, the 1997 and 2008 Technological Development Schemes and various reports by local institutes and Western consultants.

The data was generally of fair quality, albeit quite old, but generally consistent with the type and quality of information usually available in Kazakhstan.

7 REGIONAL GEOLOGY - SOUTH MANGYSHLAK BASIN

The South Mangyshlak Basin is located entirely within Kazakhstan immediately to the east of the Caspian Sea. The basin is bounded by the Mangyshlak fold-belt to the north and northeast and to the south by the Karabogaz arch where only thin Cretaceous and Tertiary rocks overlie the basement. The western boundary of the South Mangyshlak basin is not clearly defined extending into the central part of the Caspian Sea where its dimensions are unknown. The basin first formed when rifting during late Permian and Triassic times formed grabens which were subsequently filled with a thick sequence of clastic, carbonate and volcanic sediments. Compression and inversion of the area then provided the structures to form the hydrocarbon traps.

The Permo-Triassic system accounts for approximately 50 percent of the sediments in the basin and is overlain unconformably by a platform sequence of Jurassic through Eocene sediments. Lower-Middle Jurassic clastics, commonly enriched by coaly organic matter, occur at the base of this system and contain the principal producing reservoirs within the basin. The section is mainly continental in the lower part and becomes progressively more marine influenced towards the top. Subsequent marine shales and carbonates deposited during a widespread transgression in the Middle Callovian - Kimmeridgian time became the regional seal for the Lower-Middle Jurassic reservoirs.

The hydrocarbon source rocks in the South Mangyshlak Basin have not been geochemically identified but geological data indicates that the principal source rocks are stratigraphically confined to the Upper Olenekian - Middle Triassic syn-rift section which is composed of alternating shales, carbonates and tuffs. The generation of hydrocarbons probably started during the Cretaceous and continued up to the Middle Miocene. Vertical migration was dominant as indicated by the large number of stacked reservoirs in the major fields. There is also some evidence of lateral migration on the basin margins.

8 GEOLOGY OF THE TENGE FIELD

The Tenge field is associated with the Zhetybai tectonic step and is located 10 kilometers south of the giant Uzen field.

The stragrigraphic sequence present at the Tenge field consists of Paleozoic rocks, overlain by Triassic, Jurassic and Cretaceous sediments, and capped by Paleogene and younger deposits. The oldest sedimentary rocks in the field are of Paleozoic age. They were penetrated by wells TE-52 and TE-55 and are represented by beds of argillite and coarse sandstone. The Triassic sediments were penetrated by six of the drilled wells with clastic continental rocks of the Induan stage of the Lower Triassic covering the Paleozoic sediments. The thickest section of Triassic in the Tenge field belongs to an alternating sequence of shales and dark pelitomorphic carbonates of Olenekian age. Lower Triassic sediments are overlain by relatively thin Middle Triassic shales. Upper Triassic rocks mostly fill the lower parts of Zhetybai step and were denudated at the Tenge field. Triassic sediments are overlain with a strong angular unconformity by up to 100 meters of Lower Jurassic shales interbedded with some sandstone layers. The Middle Jurassic strata of Aalenian, Bajocian, Bathonian and Callovian stages comprise a thick sequence of up to 800 meters. The section consists of an irregular alternation of sandstones, siltstones and shales. Rocks of terrestrial origin (mainly alluvial facies) predominate in the section but marine interbeds occur in the upper part. The Upper Jurassic interval consists chiefly of shales with beds of marls and limestones and forms the main regional seal for hydrocarbon fields in the underlying clastics. The penetrated Upper Jurassic thickness at the Tenge field is 350 meters. The overlying Cretaceous section is predominantly marine clastic rocks with the exception of the continental Barremian shales and sands. There are carbonate intervals in the Valanginian-Hauterivian and the upper part of the Upper Cretaceous.

The present structural configuration of the Tenge field is a large elongated rather narrow anticline about 20 kilometers long and 3 kilometers wide. It trends from west-north-west to east-south-east and, as with most fields in the Zhetybai-Uzen tectonic zone, has a steep southern and gentle northern flank. The amplitude of the fold on the Bajocian Jurassic Zone 18 is 140 meters. The structure appears to have experienced no major faulting within the Middle Jurassic interval. If minor faults are present they likely do not affect the structural plan of Middle Jurassic reservoirs.

As is common in other hydrocarbon fields of the South Mangyshlak basin the Middle Jurassic stacked reservoirs of Aalenian to Callovian age are the main object of the oil and gas exploration at the Tenge field. The nomenclature of the productive sands was inherited from the nearby Uzen field. There are eleven main reservoir horizons or zones. The uppermost productive zone 13 belongs to the Callovian stage of the Middle Jurassic. Horizons 14 to 17 are associated with the Bathonian stage, 18-22 the Bajocian stage and horizon 23 the Aalenian stage. Zones 13 to 17 are fully gas bearing and have already been developed with production commencing at the start of the 1970s. Zones 18, 21, 22 and 23 are charged with both oil and gas and form the focus of this study. A discussion of each of the productive zones is presented below in more detail.

8.1 Zone 18

Zone 18 is subdivided into three sub units – 18a, 18b and 18c. All of the reservoir rocks in zone 18 are poorly to moderately sorted; they are fine to medium-grained sandstones and siltstones with argillaceous and calcareous cement. Deposition of the Middle Jurassic Bathonian stage sediments occurred in various alluvial plain settings, such as braided rivers, shallow lakes, and swamps.

Sub-unit 18a is represented by a 40 meter thick sequence of sands alternating with shale layers. The thickest reservoir quality sand was observed in wells TE-1, TE-27, TE-101, TE-7, and TE-9, where it reaches 30 meters. A gas oil contact ("GOC") was interpreted to be at 1,790 m ss based on the test results from wells TE-7, TE-8, TE-12, TE-34, and TE-52. An oil water contact ("OWC") was interpreted to be 1,802 m ss based on the test results in wells TE-34, TE-11 and TE-12. Consequently the gross oil rim thickness is 12 meters. The gas saturated gross thickness is 40 meters. Porosity and water saturation were estimated to be 17 and 35 percent respectively. From 1980 to 1990, one well (TE-131) was completed as a gas producer on this zone and produced about 9 Bcf, which is approximately two percent of the estimated original gas in place for this zone.

Sub-unit 18b has so far received the greatest oil exploration to date and appears to be the most productive of the oil bearing zones. Eighty six percent of the produced oil from the field to date comes from the 18b in wells TE-6 and TE-52. The sand development within the 18b sub-unit is variable as would be expected in this channelized environment. The greatest and most significant reservoir thickness was penetrated in wells drilled in the western, northern and eastern parts of the field with poorer reservoir quality encountered in wells drilled in the central and southern areas. Based on well test results and production data the GOC was interpreted to be 1,791 m ss and the OWC to be 1,822 m ss. The oil rim gross thickness is 31 meters, the net oil pay reaches up to 20 meters, and the gas saturated gross thickness is 30 meters. Porosity was estimated to be 17.5 percent and water saturation 35 percent.

Sub-unit 18c is interpreted from well test results to have the same contacts as sub-unit 18b and therefore also has a gross oil rim thickness of 31 meters. The 18c sand reservoir thickness varies throughout the field. The best net to gross reservoir values were observed in the western part of the pool (the area around well TE-131). The eastern area around wells TE-24, TE-17, TE-18 also shows an increase in reservoir sand thickness. The maximum net oil pay is estimated to be 18 meters in well TE-131. Porosity and water saturation were estimated to be 17 and 35 percent respectively.

8.2 Zone 21

Zone 21 has been penetrated by twenty five wells and tested in nine wells. As with zone 18, horizon 21 is divided into 3 separate units. Sub-unit 21a is represented by shales except in the most south-eastern area where well TE-24 was drilled. Sub-units 21b and 21c have been combined for the purposes of this work. They are characterized by the presence of predominantly shale rocks and poor sand development with channel bodies of limited lateral continuity. The better reservoir sands were developed in the eastern part of the field where, in the area surrounding wells TE-24, TE-109, TE-128, TE-111, the net reservoir thickness is very significant (45 meters in well TE-24). Lithology changes in the central part of the pool and zone 21 is separated into two sub-pools with different OWCs. Based on well test results and production data from well TE-58 the OWC in the western sub-pool is estimated to be at 2,034 m ss. The eastern sub-pool OWC is estimated to be at 1,986 m ss. The results of the well test on TE-27 also support the existence of a small gas cap with an estimated GOC at 1,935 m ss. Three wells (TE-58, TE-111, and TE-109) have produced 24 Mbbl of oil from horizon 21 with 90 percent of this from well TE-58. Porosity and water saturation for horizon 21 sands were estimated to be 15 and 40 percent respectively.

8.3 Zone 22

Zone 22 subdivides into two sub-units, 22a and 22b. The sandstone development within unit 22a has a clear distribution. A depositional axis of thick amalgamated sandstones is in a north-south belt through the centre of the field. These sandstones can generally either exhibit coarsening or fining upward log signature suggesting both abandoned fluvial channels and point bar deposits. The sandstone units tend to be about 25 to 30 meters thick. The underlying sub-unit 22b has a consistent log profile with the thicker developed sandstones, about 30 meters, deposited over most of the field area. In the eastern part of the field there is a sudden change in lithology with all wells drilled in the area penetrating a shale package of similar thickness. Only well TE-102 tested oil in both the 22a and 22b intervals. Based on test results of wells TE-102, TE-111 and TE-103 the GOC for sub-unit 22a is estimated to be at 2,030 m ss. Based on the lowest known level of oil in well TE-102 the OWC is estimated at a depth of 2,060 m ss. For sub-unit 22b the GOC and OWC are estimated to be at 2,075 m ss and 2,105 m ss respectively. From 1972 to 1980 gas was produced from this zone which may have caused the oil rim to partly migrate into the gas cap. For both sub-units the porosity is estimated to be 14 percent and the water saturation 35 percent.

8.4 Zone 23

Zone 23 has been penetrated by twenty two wells drilled in the Tenge field and is the deepest productive sand within the field. The sediments within the zone are associated with the upper part the Aalenian stage of the Middle Jurassic. The interval is dominated by grey, fine and medium grained sands with subordinate beds of dark-grey shales. The upper part of the zone contains the best reservoir quality sand which is encountered throughout the field and should give very good reservoir connectivity. The maximum gross oil rim thickness was estimated to be 23 meters. The maximum gross gas cap thickness is more than 40 meters. Based on well test results the GOC and OWC were defined to be at 2,140 and 2,163 m ss respectively. As with zone 22 it is not clear if the earlier gas production has affected these original contacts. Well TE-235, drilled on the southern flank of the structure, saw no evidence of the original oil rim when it was drilled in 2002. Porosity for horizon 23 was estimated to be 14 percent and water saturation 35 percent.

8.5 Net Pay Maps and Original Hydrocarbon-in-Place Estimates

Top structure maps for all the horizons were constructed based on the 3D seismic interpreted surfaces together with the correlation of well logs. McDaniel & Associates reviewed the seismic interpretation, which was provided by Tenge JV, and subsequently used it to generate the maps for the intervals of interest. For each horizon gross oil and gas thickness was calculated based on the interpreted GOC and OWC. Net reservoir thickness was interpreted from the log analysis and applied to the gross oil and gas thickness maps. For all zones (with the exception of zone 23) net oil and gas thickness maps were used as the basis for volumetric estimates of the net rock volume. Whilst these maps can be used for this purpose they cannot, due to the sparseness of the data and the channelized nature of the zones, be relied upon for well planning purposes. For zone 23 gross oil and gross gas thickness maps were used together with an average net-to-gross estimate as there is very limited well data especially in the oil section. The top structure and thickness maps for all the zones are presented in Figures 1 to 23 of the Appendix.

These estimates were then combined with the other rock and fluid parameters to determine the original oil and gas in place estimates. Average porosity values were estimated from the well logs and core analysis data. Water saturation values were estimated from selected well logs. A summary of the rock volume, petrophysical parameters and original oil in place, solution gas in place and gas cap gas in place estimates by zone are presented in Tables 6, 7 and 8 respectively of the Appendix. The reservoir and fluid properties are summarized in Table 9 of the Appendix.

9 RESERVES ESTIMATES

The crude oil and natural gas reserves were primarily based on volumetric estimates considering all available data including test data, production data, structural and net pay interpretations, amount and quality of data and economics of development. A number of reservoir simulation studies have been conducted in the past to evaluate the likely recovery that could be obtained from a Tenge field oil rim development. In 2008 Epic Consulting Services Ltd of Calgary undertook a sector modeling study on behalf of McDaniel & Associates to investigate the sensitivity of oil recovery to well spacing and production rate within the oil rims of zones 18b and 18c. These studies combined with analogue data have been used to estimate the ranges of recovery factors used in this evaluation. The reserves were classified into Proved Developed Producing ("PDP"), Proved Undeveloped ("PUD"), Total Proved ("1P"), Proved plus Probable ("2P") and Proved plus Probable plus Possible ("3P") classes as defined in Section 5 of this report. In this evaluation the PUD is the difference between the 1P and PDP.

Gas reserves have been assigned as part of this evaluation as the field is close to gas export pipelines and the gas market in Western Kazakhstan is to some degree established. Proved gas reserves have not been assigned as there is no gas sales contract in place for the zones being evaluated.

For the analysis of reserves, each zone was categorized according to the type of development that would be applicable given the reservoir and fluid characteristics. Zone 18a only has a 12 meter gross oil column, underlain by water and overlain by gas, which is likely too thin for a viable oil rim development. Well tests all show high GORs and fairly low oil rates so it was assumed that zone 18a will be developed as a gas reservoir using vertical wells and that the oil recovery would be very low.

Zones 18b and 18c both have a 31 meter gross oil column, underlain by water and overlain by gas, and development of the oil rims should be viable if horizontal wells are employed. Due to the geometry of these sands, 500 to 1,000 meter horizontal wells could be oriented in a radial direction allowing them to target both intervals in a single well. At the eastern and western ends of the field the horizontal distances between zones appears to be too large to develop both intervals in the same well thus some additional wells will be required. In total it is estimated that 32 horizontal wells will be required to develop the 18b and 18c oil rims.

Zone 21 is divided into an eastern and western part. The western part does not appear to have a gas cap, but is low relief and thin and the development of only a portion of the area is likely to be viable. The eastern part should give better recovery as it is thicker with a gross oil column of up to 51 meters although it does have a small gas cap.

Zones 22 and 23 both initially had oil rims although it is not clear if the gas production (estimated to be 90 Bcf) that has already occurred from these two intervals has negatively impacted the potential recovery from the oil rims. The limited data available suggests the rim on zone 23 may no longer be intact; well TE-235 did not encounter high oil saturations when drilled in what should have been a rim location and well TE-109 tested water while swabbing in 1997 from what should have been an oil rim location. It may be that there are explanations for the results of these two wells which still allow for an oil rim to be present, however, it was forecast in this evaluation that the future development would focus on the blowdown of the gas caps and that any oil recovery would be very low.

The concept for the reservoirs with a viable oil development (18b, 18c, 21 East and 21 West) was to first develop the oil, re-injecting any produced gas, followed in all cases (except zone 21 West) by a gas cap blowdown. For the reservoirs where it was felt that an oil development was not viable (18a, 22a, 22b and 23) it was assumed that the gas would be developed immediately.

Crude Oil Reserves

A very small quantity of proved producing oil reserves (393 Mbbl) were assigned on the basis of production analysis of the existing four wells, three of which produce from zone 18b and the other which produces from zone 21.

Proved undeveloped oil reserves were only assigned to zones 18b and 18c assuming that roughly half their reservoir area is proved. A development using 16 horizontal wells and 2 new vertical wells was estimated to give a 10 percent recovery for 50 percent of the mapped in place volume.

The 2P oil reserves for zones 18b and 18c assume a development of the full mapped area using 32 horizontal wells and 2 new vertical wells. These producers are assumed to be supported by 10 gas cap injectors (vertical) and 10 water leg injectors (horizontal) giving a recovery factor of 25 percent. The 3P oil reserves are based on the same numbers of wells but with a 25 percent increase in the oil in place and a 30 percent recovery factor.

The 2P oil reserves for zone 21 East are based on a development of the thickest net pay areas, which is assumed to be 50 percent of the oil in place, requiring five producers (horizontal), 2 gas injectors (vertical) and 2 water injectors (vertical) giving a recovery factor of 20 percent. The 3P oil reserves assume the full oil in place can be developed using double the number of wells resulting in a 25 percent recovery factor.

The 2P oil reserves for zone 21 West assume 25 percent of the oil-in-place is developed using 2 new producers (vertical) giving a recovery factor of 15 percent. The 3P oil reserves assume 9 new producers are required to develop the full mapped area with a resulting 20 percent recovery factor.

For the reservoirs where a gas blowdown is assumed to occur immediately a small amount of oil reserves were assigned to the 2P and 3P cases. For interval 18a a 2P and 3P recovery factor of 4 and 10 percent respectively were assumed. For zones 22 and 23 a 2P and 3P recovery factor of 2 and 5 percent respectively were assumed reflecting the fact that the oil rim may not be present in some areas of the field.

Solution Gas Reserves

Solution gas will be recovered during the blowdown phases of each reservoir development. For the oil rim developments the solution gas will be re-injected until the blowdown phase commences. The solution gas recovery factors were estimated to vary between the oil recovery factors and the gas cap gas recovery factors. No proved gas reserves were assigned as there currently are no gas sales contracts in place. A shrinkage factor of 10 percent was applied to convert the raw gas volumes to sales gas volumes.

Gas Cap Gas Reserves

Gas cap gas will be recovered during the blowdown phases of each reservoir development. No proved gas reserves were assigned as there currently are no gas sales contracts in place. The gas cap gas recovery factors are expected to be in line with typical depletion drive gas recovery factors. Reservoirs in the Mangyshlak area do not typically have strong aquifer support and so the recoveries should be relatively high. For calculating 2P reserves a recovery factor of 70 percent was applied to the mapped gas cap gas in place. For calculating 3P reserves a recovery factor of 80 percent was applied to 125 percent of the mapped gas cap gas in place. A shrinkage factor of 10 percent was applied to convert the raw gas volumes to sales gas volumes.

Where possible, wells that were used for gas injection during the oil rim development phase will later be converted to gas producers during the blowdown phase. The 2P case assumes 38 gas producers will be required with 10 coming from the conversion of injectors and 28 new wells. The 3P case assumes 38 gas producers will be required with 12 coming from the conversion of injectors and 26 new wells.

Summaries of the oil, solution gas and gas cap gas reserves by zone are presented in Tables 6, 7 and 8 respectively of the Appendix. These reserves are based on the full life of the field and are prior to the application of the contract expiry cut-off in September 5, 2020. Reservoir and fluid properties are summarized in Table 9 of the Appendix.

Standard industry practice for reserves evaluations in a country that does not have a history of production contract extensions past the contract expiry date (such as Kazakhstan) is to only assign reserves that are forecast to be produced up to the contract expiry date. Those reserves to the end of the contract are presented on a property gross, company gross and company net basis in Table 4.

Table 4 - Reserves to End of Contract, September 5, 2020

	PDP	PUD	1P	Probable	2P	Possible	3P
Crude Oil, Mbbl							
Property Gross	393	8,165	8,558	45,443	54,000	35,916	89,917
Company Gross (2)	393	8,165	8,558	45,443	54,000	35,916	89,917
Company Net (3)	369	7,620	7,989	40,539	48,529	31,267	79,796
Natural Gas, MMcf							
Property Gross	-	-	-	209,267	209,267	126,047	335,313
Company Gross (2)	-	-	-	209,267	209,267	126,047	335,313
Company Net (3)	-	-	-	188,340	188,340	113,442	301,782
Barrels of Oil Equiv. (4)							
Property Gross	393	8,165	8,558	80,320	88,878	56,924	145,802
Company Gross (2)	393	8,165	8,558	80,320	88,878	56,924	145,802
Company Net (3)	369	7,620	7,989	71,929	79,919	50,174	130,093

(1) Reserves at March 31, 2011 are estimated to the end of the current contract (September 5, 2020).
(2) Gross reserves include Tenge JV's 100 percent working interest reserves before deductions of royalty.
(3) Net reserves include gross reserves after deduction of royalty.
(4) Based on a conversion of 6 thousand cubic feet of natural gas equal to 1 barrel of oil equivalent.

Tenge believes that it will be possible to negotiate a contract extension past 2020 to allow all the oil and gas to be recovered. The reserves expected to be produced to the end of the field life are also presented in Table 5 for illustrative purposes.

Table 5 - Reserves to End of Field Life – Presented for Illustrative Purposes Only

	PDP	PUD	1P	Probable	2P	Possible	3P
Crude Oil, Mbbl (1)							
Property Gross	393	8,217	8,610	49,808	58,418	47,781	106,199
Company Gross (2)	393	8,217	8,610	49,808	58,418	47,781	106,199
Company Net (3)	369	7,669	8,038	44,537	52,575	41,985	94,560
Natural Gas, MMcf (1)							
Property Gross	-	-	-	545,501	545,501	292,776	838,277
Company Gross (2)	-	-	-	545,501	545,501	292,776	838,277
Company Net (3)	-	-	-	490,951	490,951	263,498	754,449
Barrels of Oil Equiv.(4)							
Property Gross	393	8,217	8,610	140,725	149,335	96,577	245,912
Company Gross (2)	393	8,217	8,610	140,725	149,335	96,577	245,912
Company Net (3)	369	7,669	8,038	126,363	134,400	85,901	220,302

(1) Reserves at March 31, 2011 are estimated to the end of the field life
(2) Gross reserves include Tenge JV's 100 percent working interest reserves before deductions of royalty.
(3) Net reserves include gross reserves after deduction of royalty.
(4) Based on a conversion of 6 thousand cubic feet of natural gas equal to 1 barrel of oil equivalent.

10 PRICE FORECASTS

The net present value estimates were based on the McDaniel & Associates December 31, 2010 price forecast. The crude oil export price is based on the forecast Brent crude oil price less an estimate of the price differential between the Brent reference price and the field price. This differential includes the cost of crude processing, transporting the crude from the field to the point of sale and all other related commercial costs to market the oil. Based on the oil sales information for 2010 the total price differential has averaged $18.50/bbl during the year and this has been used for forecasting oil price. There are specific clauses within the Tenge sub-soil contract that allow for 100 percent crude oil export. Tenge JV is currently exporting all the oil it produces and 100 percent future export has been assumed.

Natural gas prices are based on the published gas prices paid by Gazprom in the region. These have been indirectly linked to European gas prices which in turn track the Brent crude oil price to allow for future price changes.

A summary of the reference crude oil and natural gas price forecasts are presented in Table 11 of the Appendix.

11 NET PRESENT VALUES

The net present values of the crude oil and natural gas reserves were based on future production and revenue analyses. Estimates are provided both to the current contract expiry date of September 5, 2020 (Table 6) and for illustrative purposes to the end of the field life (Table 7). All of the net present value estimates presented in this report were presented in US dollars and include an allowance for Kazakhstan taxes.

The future production forecasts were based on detailed calculations including allowances for future drilling or recompletions. Tenge JV believes it will be possible to have a maximum of six rigs working in the Tenge field each drilling up to eight vertical or five horizontal wells per year. In 2011 it is planned to drill four vertical wells to appraise the zone 18b, 18c and 21 oil rims. Three of these vertical wells will later be replaced by horizontal wells at which point they will be converted to gas producers on zone 18a. Whilst facilities are being constructed any associated gas produced will be supplied free of charge to the Kazakh Gas Processing Plant (subsidiary of UzenMunaiGaz).

Future crude oil revenue was derived by employing the forecast production and the forecast crude oil price discussed in Section 10. An allowance for customs export duty (re-introduced at the beginning of 2011), mineral extraction and export rent taxes and income taxes were made according to the terms of the contract. Current unit operating costs are very high because of the very low production levels. Future operating costs are based on our experience with analogous oil and gas projects. Drilling costs are based on budget estimates provided by Tenge JV which indicates a vertical well will cost $3.4 million and a horizontal well will cost $5.5 million. Tenge JV provided some preliminary facility cost estimates from two local design institutes for a small scale production facility which were used to benchmark our estimates of the likely facility costs. An allowance was also made for well abandonment costs at the end of each respective forecast.

Table 1 of the Appendix presents a summary of the reserves and net present values to the end of the contract. Tables 2 to 5 of the Appendix present the revenue forecasts to the end of the contract for each reserves category. For illustrative purposes only, the same information to the end of the field life is presented in Tables 13 to 17 of the Appendix. (The small amount of associated gas produced whilst facilities are being built is excluded from the reserves presented in these tables as no revenue is derived).

Table 10 of the Appendix provides a summary of the economic parameters and Table 12 of the Appendix provides a breakdown of the capital costs.

Table 6 - Net Present Values to End of Contract, September 5, 2020

	Net Present Values at December 31, 2010 (1) (US$1000) Discounted At				
	0%	5%	10%	15%	20%
Before Income Taxes (2) (3)					
Proved Producing Reserves	14,384	12,132	10,432	9,119	8,084
Proved Undeveloped Reserves	174,804	125,761	90,510	64,745	45,639
Total Proved Reserves	189,188	137,893	100,943	73,865	53,724
Probable Reserves	2,054,269	1,505,937	1,123,342	850,304	651,505
Total Proved + Probable Reserves	2,243,457	1,643,831	1,224,284	924,169	705,229
Possible Reserves	1,789,182	1,306,476	971,573	733,989	562,051
Total Proved + Probable + Possible Reserves	4,032,639	2,950,306	2,195,857	1,658,158	1,267,280
After Income Taxes (2) (3)					
Proved Producing Reserves	13,844	11,673	10,035	8,769	7,771
Proved Undeveloped Reserves	122,530	83,972	56,596	36,852	22,426
Total Proved Reserves	136,374	95,645	66,630	45,621	30,196
Probable Reserves	1,252,495	899,356	654,424	480,834	355,437
Total Proved + Probable Reserves	1,388,868	995,002	721,054	526,455	385,633
Possible Reserves	1,048,917	760,670	560,400	418,244	315,393
Total Proved + Probable + Possible Reserves	2,437,785	1,755,671	1,281,454	944,699	701,026

(1) Net present values are estimated to the end of the current contract (September 5, 2020).
(2) The net present values may not necessarily represent the fair market value of the reserves.
(3) The value of all wells and facilities are included in the net present value estimates

Table 7 - Net Present Values to End of Field Life – Presented for Illustrative Purposes Only

	Net Present Values at December 31, 2010 (1) (US$1000) Discounted At				
	0%	5%	10%	15%	20%
Before Income Taxes (2) (3)					
Proved Producing Reserves	14,384	12,132	10,432	9,119	8,084
Proved Undeveloped Reserves	175,674	126,309	90,862	64,976	45,793
Total Proved Reserves	190,058	138,441	101,294	74,095	53,878
Probable Reserves	3,958,104	2,414,494	1,586,099	1,099,452	792,141
Total Proved + Probable Reserves	4,148,163	2,552,935	1,687,394	1,173,547	846,018
Possible Reserves	3,084,566	1,980,115	1,339,360	943,199	685,314
Total Proved + Probable + Possible Reserves	7,232,729	4,533,050	3,026,754	2,116,746	1,531,332
After Income Taxes (2) (3)					
Proved Producing Reserves	13,844	11,673	10,035	8,769	7,771
Proved Undeveloped Reserves	123,148	84,361	56,846	37,016	22,535
Total Proved Reserves	136,991	96,034	66,880	45,785	30,306
Probable Reserves	2,098,719	1,318,998	876,054	604,181	427,156
Total Proved + Probable Reserves	2,235,710	1,415,032	942,934	649,966	457,462
Possible Reserves	1,779,980	1,146,909	773,558	540,367	387,677
Total Proved + Probable + Possible Reserves	4,015,690	2,561,941	1,716,492	1,190,333	845,139

(1) Net present values are estimated to the end of the field life.
(2) The net present values may not necessarily represent the fair market value of the reserves.
(3) The value of all wells and facilities are included in the net present value estimates

12 PROFESSIONAL QUALIFICATIONS

McDaniel & Associates Consultants Ltd. has over 50 years of experience in the evaluation of oil and gas properties. McDaniel& Associates Consultants Ltd. is registered with the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA). All of the professionals involved in the preparation of this report have in excess of 5 years of experience in the evaluation of oil and gas properties. Mr. Bryan Emslie, Senior Vice President, Mr. Paul Taylor, Senior Petroleum Engineer and Mr. Anatoli Tchernavskikh, Manager International Geology, all with McDaniel & Associates Consultants Ltd., were responsible for the preparation of this report. Mr. Emslie has over 30 years of experience in the evaluation of oil and gas properties, Mr. Taylor have over 20 years of experience and Mr. Anatoli Tchernavskikh has in excess of 19 years. All of the persons involved in the preparation of this report and McDaniel & Associates Consultants Ltd. are independent of Tenge JV.

In preparing this report, we relied upon factual information including ownership, technical well and seismic data, contracts, and other relevant data supplied by Tenge JV. The extent and character of all factual information supplied were relied upon by us in preparing this report and has been accepted as represented without independent verification. We have relied upon representations made by Tenge JV as to the completeness and accuracy of the data provided and that all data proved to us was lawfully acquired.

This report was prepared by McDaniel & Associates Consultants Ltd. for the exclusive use of Tenge JV. Tenge JV agrees not to use the report in securities transactions without the prior written consent of McDaniel & Associates Consultants Ltd., which McDaniel & Associates Consultants Ltd. shall not unreasonably withhold. We reserve the right to revise any opinions provided herein if any relevant data existing prior to preparation of this report was not made available or if any data provided is found to be erroneous.

Sincerely,

McDANIEL & ASSOCIATES CONSULTANTS LTD.
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Table 1

Tenge JV
Tenge Field - Kazakhstan - Competent Person's Report
Summary of Reserves and Net Present Values to End of Contract
Effective December 31, 2010

Summary of Reserves (1)

Reserve Category	Crude Oil Reserves - bbls Property Gross Mbbl	Crude Oil Reserves - bbls Company Gross Mbbl	Crude Oil Reserves - bbls Company Net Mbbl	Crude Oil Reserves - Tonnes Property Gross MT	Crude Oil Reserves - Tonnes Company Gross MT	Crude Oil Reserves - Tonnes Company Net MT
Proved Developed Producing Reserves	393	393	369	53	53	50
Proved Undeveloped Reserves	8,165	8,165	7,620	1,102	1,102	1,029
Total Proved Reserves	8,558	8,558	7,989	1,155	1,155	1,078
Probable Reserves	45,443	45,443	40,539	6,136	6,136	5,474
Proved Plus Probable Reserves	54,000	54,000	48,529	7,291	7,291	6,552
Possible Reserves	35,916	35,916	31,267	4,853	4,853	4,225
Proved Plus Probable Plus Possible Reserves	89,917	89,917	79,796	12,144	12,144	10,777

Reserve Category	Natural Gas Reserves - scf Property Gross MMcf	Natural Gas Reserves - scf Company Gross MMcf	Natural Gas Reserves - scf Company Net MMcf	Barrels of Oil Equivalent Property Gross Mboe	Barrels of Oil Equivalent Company Gross Mboe	Barrels of Oil Equivalent Company Net Mboe
Proved Developed Producing Reserves	-	-	-	393	393	369
Proved Undeveloped Reserves	-	-	-	8,165	8,165	7,620
Total Proved Reserves	-	-	-	8,558	8,558	7,989
Probable Reserves	209,267	209,267	188,340	80,320	80,320	71,929
Proved Plus Probable Reserves	209,267	209,267	188,340	88,878	88,878	79,919
Possible Reserves	126,047	126,047	113,442	56,924	56,924	50,174
Proved Plus Probable Plus Possible Reserves	335,313	335,313	301,782	145,802	145,802	130,093

Summary of Company Share of Net Present Values Before Income Taxes

Reserve Category	$M US Dollars 0.0%	5.0%	10.0%	15.0%	20.0%
Proved Developed Producing Reserves	14,384	12,132	10,432	9,119	8,084
Proved Undeveloped Reserves	174,804	125,761	90,510	64,745	45,639
Total Proved Reserves	189,188	137,893	100,943	73,865	53,724
Probable Reserves	2,054,269	1,505,937	1,123,342	850,304	651,505
Proved Plus Probable Reserves	2,243,457	1,643,831	1,224,284	924,169	705,229
Possible Reserves	1,789,182	1,306,476	971,573	733,989	562,051
Proved Plus Probable Plus Possible Reserves	4,032,639	2,950,306	2,195,857	1,658,158	1,267,280

Summary of Company Share of Net Present Values After Income Taxes

Reserve Category	$M US Dollars 0.0%	5.0%	10.0%	15.0%	20.0%
Proved Developed Producing Reserves	13,844	11,673	10,035	8,769	7,771
Proved Undeveloped Reserves	122,530	83,972	56,596	36,852	22,426
Total Proved Reserves	136,374	95,645	66,630	45,621	30,196
Probable Reserves	1,252,495	899,356	654,424	480,834	355,437
Proved Plus Probable Reserves	1,388,868	995,002	721,054	526,455	385,633
Possible Reserves	1,048,917	760,670	560,400	418,244	315,393
Proved Plus Probable Plus Possible Reserves	2,437,785	1,755,671	1,281,454	944,699	701,026

(1) Company Gross reserves are based on Company working interest share of the reserves.
Company Net reserves are based on Company working interest share of reserves after royalties.

Tenge JV

Table 2

Tenge Field - Kazakhstan - Competent Person's Report
Forecast of Production and Revenues to End of Contract
Proved Developed Producing Reserves
Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

		Crude Oil					Natural Gas				Total	Total
Year	Producing Well Count	Daily Rate Bopd	Annual Volume Mbbl	Annual Volume MT	Crude Oil Price US$/bbl	Sales Revenue US$M	Daily Rate Mcfpd	Annual Volume MMcf	Nat Gas Price US$/Mcf	Sales Revenue US$M	Oil&Gas BOE Mbbl	Sales Revenue US$M
2011	4	218	80	11	66.50	5,295	-	-	-	-	80	5,295
2012	4	183	67	9	68.33	4,566	-	-	-	-	67	4,566
2013	4	154	56	8	70.25	3,939	-	-	-	-	56	3,939
2014	4	129	47	6	72.67	3,419	-	-	-	-	47	3,419
2015	4	108	39	5	75.18	2,968	-	-	-	-	39	2,968
2016	4	91	33	4	77.87	2,579	-	-	-	-	33	2,579
2017	4	76	28	4	79.47	2,209	-	-	-	-	28	2,209
2018	4	64	23	3	81.05	1,890	-	-	-	-	23	1,890
2019	3	54	20	3	82.52	1,615	-	-	-	-	20	1,615
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.		-	-	-	-	-	-	-	-	-	-	-
Total			393	53	-	28,479		-	-	-	393	28,479

Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	430	265	5.0	900	1,633	20.51	-	40	2,028	103	-	1,924
2012	361	228	5.0	776	846	12.66	-	41	2,313	88	-	2,225
2013	303	236	6.0	670	316	5.64	-	42	2,372	76	-	2,297
2014	254	239	7.0	650	313	6.66	-	42	1,920	65	-	1,856
2015	213	208	7.0	564	311	7.88	-	43	1,628	56	-	1,573
2016	179	181	7.0	490	310	9.37	-	44	1,375	48	-	1,328
2017	150	155	7.0	464	280	10.08	-	-	1,160	41	-	1,119
2018	126	132	7.0	397	250	10.74	-	-	985	35	-	950
2019	106	113	7.0	339	221	11.28	234	-	602	30	-	572
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,120	1,757	6.2	5,249	4,481	11.41	234	252	14,384	541	-	13,844

Company Working Interest Share of Production and Revenues Before and After tax

Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	80	76	5,295	1,595	1,633	40	2,028	103	-	1,924	1,924	1,835
2012	67	63	4,566	1,365	846	41	2,313	88	-	2,225	4,150	1,929
2013	56	53	3,939	1,209	316	42	2,372	76	-	2,297	6,446	1,810
2014	47	44	3,419	1,143	313	42	1,920	65	-	1,856	8,302	1,329
2015	39	37	2,968	985	311	43	1,628	56	-	1,573	9,875	1,024
2016	33	31	2,579	849	310	44	1,375	48	-	1,328	11,202	786
2017	28	26	2,209	768	280	-	1,160	41	-	1,119	12,321	602
2018	23	22	1,890	655	250	-	985	35	-	950	13,271	465
2019	20	18	1,615	558	221	234	602	30	-	572	13,844	255
2020	-	-	-	-	-	-	-	-	-	-	13,844	-
2021	-	-	-	-	-	-	-	-	-	-	13,844	-
2022	-	-	-	-	-	-	-	-	-	-	13,844	-
2023	-	-	-	-	-	-	-	-	-	-	13,844	-
2024	-	-	-	-	-	-	-	-	-	-	13,844	-
2025	-	-	-	-	-	-	-	-	-	-	13,844	-
Rem.	-	-	-	-	-	-	-	-	-	-	13,844	-
Total	393	369	28,479	9,127	4,481	487	14,384	541	-	13,844		10,035

Tenge JV

Table 3

Tenge Field - Kazakhstan - Competent Person's Report
Forecast of Production and Revenues to End of Contract
Total Proved Reserves
Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

		Crude Oil					Natural Gas				Total	Total
Year	Producing Well Count	Daily Rate Bopd	Annual Volume Mbbl	Annual Volume MT	Crude Oil Price US$/bbl	Sales Revenue US$M	Daily Rate Mcfpd	Annual Volume MMcf	Nat Gas Price US$/Mcf	Sales Revenue US$M	Oil&Gas BOE Mbbl	Sales Revenue US$M
2011	5	328	120	16	66.50	7,965	-	-	-	-	120	7,965
2012	10	1,800	657	89	68.33	44,898	-	-	-	-	657	44,898
2013	16	4,112	1,501	203	70.25	105,432	-	-	-	-	1,501	105,432
2014	20	4,951	1,807	244	72.67	131,312	-	-	-	-	1,807	131,312
2015	20	4,453	1,625	219	75.18	122,188	-	-	-	-	1,625	122,188
2016	20	3,055	1,115	151	77.87	86,835	-	-	-	-	1,115	86,835
2017	20	2,101	767	104	79.47	60,937	-	-	-	-	767	60,937
2018	19	1,449	529	71	81.05	42,874	-	-	-	-	529	42,874
2019	18	910	332	45	82.52	27,409	-	-	-	-	332	27,409
2020	17	287	105	14	84.29	8,830	-	-	-	-	105	8,830
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.		-	-	-	-	-	-	-	-	-	-	-
Total			8,558	1,155	-	638,679		-	-	-	8,558	638,679

Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	647	398	5.0	1,354	2,039	17.03	-	12,602	(9,075)	183	-	(9,259)
2012	3,548	2,245	5.0	7,633	4,836	7.36	-	71,375	(44,738)	691	-	(45,429)
2013	8,103	6,326	6.0	17,923	8,261	5.50	-	66,360	(1,541)	3,868	-	(5,409)
2014	9,756	9,192	7.0	24,949	9,697	5.37	-	23,559	54,159	9,968	5,247	38,944
2015	8,776	8,553	7.0	23,216	9,399	5.78	-	216	72,027	9,524	5,750	56,754
2016	6,020	6,078	7.0	16,499	8,179	7.33	-	221	49,838	6,391	2,611	40,837
2017	4,140	4,266	7.0	12,797	7,362	9.60	-	225	32,148	3,903	476	27,768
2018	2,856	3,001	7.0	9,003	6,196	11.71	-	-	21,817	2,464	-	19,353
2019	1,793	1,919	7.0	5,756	5,128	15.44	-	-	12,813	1,234	-	11,579
2020	566	618	7.0	1,854	2,737	26.13	1,315	-	1,740	505	-	1,235
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	46,205	42,596	6.7	120,984	63,833	7.46	1,315	174,558	189,188	38,730	14,084	136,374
								-				

Company Working Interest Share of Production and Revenues Before and After tax

Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	120	114	7,965	2,399	2,039	12,602	(9,075)	183	-	(9,259)	(9,259)	(8,828)
2012	657	624	44,898	13,425	4,836	71,375	(44,738)	691	-	(45,429)	(54,688)	(39,377)
2013	1,501	1,411	105,432	32,352	8,261	66,360	(1,541)	3,868	-	(5,409)	(60,097)	(4,262)
2014	1,807	1,681	131,312	43,897	9,697	23,559	54,159	9,968	5,247	38,944	(21,153)	27,897
2015	1,625	1,512	122,188	40,544	9,399	216	72,027	9,524	5,750	56,754	35,601	36,960
2016	1,115	1,037	86,835	28,597	8,179	221	49,838	6,391	2,611	40,837	76,438	24,176
2017	767	713	60,937	21,203	7,362	225	32,148	3,903	476	27,768	104,206	14,945
2018	529	492	42,874	14,861	6,196	-	21,817	2,464	-	19,353	123,559	9,469
2019	332	309	27,409	9,468	5,128	-	12,813	1,234	-	11,579	135,138	5,150
2020	105	97	8,830	3,038	2,737	1,315	1,740	505	-	1,235	136,374	500
2021	-	-	-	-	-	-	-	-	-	-	136,374	-
2022	-	-	-	-	-	-	-	-	-	-	136,374	-
2023	-	-	-	-	-	-	-	-	-	-	136,374	-
2024	-	-	-	-	-	-	-	-	-	-	136,374	-
2025	-	-	-	-	-	-	-	-	-	-	136,374	-
Rem.	-	-	-	-	-	-	-	-	-	-	136,374	-
Total	8,558	7,989	638,679	209,785	63,833	175,873	189,188	38,730	14,084	136,374		66,630

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Table 4

Tenge Field - Kazakhstan - Competent Person's Report
Forecast of Production and Revenues to End of Contract
Total Proved + Probable Reserves
Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

		Crude Oil					Natural Gas				Total	Total
Year	Producing Well Count	Daily Rate Bopd	Annual Volume Mbbl	Annual Volume MT	Crude Oil Price US$/bbl	Sales Revenue US$M	Daily Rate Mcfpd	Annual Volume MMcf	Nat Gas Price US$/Mcf	Sales Revenue US$M	Oil&Gas BOE Mbbl	Sales Revenue US$M
2011	6	416	152	20	66.50	10,089	-	-	-	-	152	10,089
2012	13	5,075	1,852	250	68.33	126,578	-	-	-	-	1,852	126,578
2013	38	17,074	6,232	841	70.25	437,825	40,000	14,600	3.32	48,446	8,665	486,272
2014	61	27,606	10,076	1,360	72.67	732,209	80,000	29,200	3.74	109,186	14,943	841,395
2015	72	28,868	10,537	1,423	75.18	792,094	80,000	29,200	4.14	120,838	15,403	912,932
2016	73	22,925	8,368	1,130	77.87	651,633	80,000	29,200	4.54	132,493	13,234	784,126
2017	71	17,467	6,375	861	79.47	506,628	80,000	29,200	4.81	140,407	11,242	647,035
2018	74	13,329	4,865	657	81.05	394,304	80,000	29,200	5.06	147,840	9,732	542,144
2019	77	10,058	3,671	496	82.52	302,950	80,000	29,200	5.30	154,834	8,538	457,784
2020	75	5,129	1,872	253	84.29	157,804	53,333	19,467	5.53	107,608	5,117	265,413
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.		-	-	-	-	-	-	-	-	-	-	-
Total			54,000	7,291	-	4,112,115		209,267	-	961,651	88,878	5,073,766

Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	819	504	5.0	1,715	5,031	33.16	-	48,475	(46,456)	412	-	(46,868)
2012	9,999	6,329	5.0	21,518	18,647	10.07	-	225,611	(155,526)	2,098	-	(157,624)
2013	33,654	44,249	9.1	74,430	43,342	5.00	-	282,958	7,639	37,782	16,318	(46,462)
2014	54,417	91,462	10.9	139,120	61,340	4.10	-	145,980	349,077	67,077	64,428	217,572
2015	56,903	99,214	10.9	150,498	65,421	4.25	-	12,383	528,514	75,610	85,719	367,185
2016	45,191	84,929	10.8	123,810	62,112	4.69	-	497	467,587	65,575	80,290	321,721
2017	34,433	64,703	10.0	106,392	58,472	5.20	-	23,638	359,397	53,112	62,984	243,300
2018	26,277	54,214	10.0	82,804	56,684	5.82	-	24,660	297,504	44,340	53,665	199,499
2019	19,830	42,749	9.3	63,620	55,563	6.51	-	1,038	274,985	38,133	51,583	185,269
2020	10,114	24,963	9.4	33,139	36,168	7.07	-	292	160,737	22,300	33,162	105,275
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	291,636	513,317	10.1	797,046	462,779	5.21	-	765,533	2,243,457	406,439	448,149	1,388,868
								-				

Company Working Interest Share of Production and Revenues Before and After tax

Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	152	144	10,089	3,038	5,031	48,475	(46,456)	412	-	(46,868)	(46,868)	(44,687)
2012	1,852	1,760	126,578	37,846	18,647	225,611	(155,526)	2,098	-	(157,624)	(204,492)	(136,626)
2013	8,665	7,861	486,272	152,333	43,342	282,958	7,639	37,782	16,318	(46,462)	(250,953)	(36,611)
2014	14,943	13,348	841,395	284,998	61,340	145,980	349,077	67,077	64,428	217,572	(33,382)	155,858
2015	15,403	13,758	912,932	306,615	65,421	12,383	528,514	75,610	85,719	367,185	333,803	239,121
2016	13,234	11,827	784,126	253,930	62,112	497	467,587	65,575	80,290	321,721	655,525	190,467
2017	11,242	10,118	647,035	205,528	58,472	23,638	359,397	53,112	62,984	243,300	898,825	130,945
2018	9,732	8,758	542,144	163,296	56,684	24,660	297,504	44,340	53,665	199,499	1,098,324	97,610
2019	8,538	7,721	457,784	126,198	55,563	1,038	274,985	38,133	51,583	185,269	1,283,593	82,407
2020	5,117	4,624	265,413	68,216	36,168	292	160,737	22,300	33,162	105,275	1,388,868	42,569
2021	-	-	-	-	-	-	-	-	-	-	1,388,868	-
2022	-	-	-	-	-	-	-	-	-	-	1,388,868	-
2023	-	-	-	-	-	-	-	-	-	-	1,388,868	-
2024	-	-	-	-	-	-	-	-	-	-	1,388,868	-
2025	-	-	-	-	-	-	-	-	-	-	1,388,868	-
Rem.	-	-	-	-	-	-	-	-	-	-	1,388,868	-
Total	88,878	79,919	5,073,766	1,601,998	462,779	765,533	2,243,457	406,439	448,149	1,388,868		721,054

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Table 5

Tenge Field - Kazakhstan - Competent Person's Report
Forecast of Production and Revenues to End of Contract
Total Proved + Probable + Possible Reserves
Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

		Crude Oil					Natural Gas				Total	Total
Year	Producing Well Count	Daily Rate Bopd	Annual Volume Mbbl	Annual Volume MT	Crude Oil Price US$/bbl	Sales Revenue US$M	Daily Rate Mcfpd	Annual Volume MMcf	Nat Gas Price US$/Mcf	Sales Revenue US$M	Oil&Gas BOE Mbbl	Sales Revenue US$M
2011	6	416	152	20	66.50	10,089	-	-	-	-	152	10,089
2012	13	5,075	1,852	250	68.33	126,578	-	-	-	-	1,852	126,578
2013	38	21,375	7,802	1,054	70.25	548,105	52,000	18,980	3.32	62,980	10,965	611,085
2014	64	40,742	14,871	2,009	72.67	1,080,638	130,000	47,450	3.74	177,427	22,779	1,258,065
2015	80	45,815	16,722	2,259	75.18	1,257,102	130,000	47,450	4.14	196,362	24,631	1,453,463
2016	80	41,735	15,233	2,058	77.87	1,186,286	130,000	47,450	4.54	215,300	23,142	1,401,586
2017	77	33,111	12,086	1,632	79.47	960,389	130,000	47,450	4.81	228,161	19,994	1,188,550
2018	74	26,281	9,593	1,296	81.05	777,482	130,000	47,450	5.06	240,240	17,501	1,017,722
2019	78	20,790	7,588	1,025	82.52	626,219	130,000	47,450	5.30	251,605	15,497	877,824
2020	82	11,007	4,017	543	84.29	338,633	86,667	31,633	5.53	174,863	9,290	513,497
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.		-	-	-	-	-	-	-	-	-	-	-
Total			89,917	12,145	-	6,911,520		335,313	-	1,546,938	145,802	8,458,458

Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	819	504	5.0	1,715	6,031	39.75	-	66,563	(65,544)	527	-	(66,071)
2012	9,996	6,329	5.0	21,518	22,727	12.27	-	294,092	(228,085)	2,747	-	(230,832)
2013	42,144	61,109	10.0	93,178	55,346	5.05	-	341,607	17,701	43,822	14,828	(40,949)
2014	80,355	147,419	11.7	205,321	84,238	3.70	-	171,290	569,441	102,314	111,316	355,812
2015	90,346	170,488	11.7	238,849	93,171	3.78	-	54,159	806,449	121,618	151,353	533,478
2016	82,311	163,884	11.7	225,394	92,157	3.98	-	591	837,249	119,607	163,967	553,675
2017	65,299	128,459	10.8	201,682	87,146	4.36	-	572	705,392	100,729	139,833	464,830
2018	51,828	109,547	10.8	163,271	83,248	4.76	-	555	609,274	87,077	128,708	393,488
2019	40,997	94,045	10.7	131,506	81,710	5.27	-	38,173	491,394	75,049	114,662	301,683
2020	21,704	51,350	10.0	71,113	54,023	5.82	-	25,939	289,368	44,505	72,192	172,670
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	485,799	933,134	11.0	1,353,548	659,798	4.53	-	993,541	4,032,639	697,996	896,858	2,437,785
								-				

Company Working Interest Share of Production and Revenues Before and After tax

Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	152	144	10,089	3,038	6,031	66,563	(65,544)	527	-	(66,071)	(66,071)	(62,996)
2012	1,852	1,760	126,578	37,843	22,727	294,092	(228,085)	2,747	-	(230,832)	(296,903)	(200,082)
2013	10,965	9,869	611,085	196,431	55,346	341,607	17,701	43,822	14,828	(40,949)	(337,852)	(32,267)
2014	22,779	20,204	1,258,065	433,096	84,238	171,290	569,441	102,314	111,316	355,812	17,960	254,886
2015	24,631	21,833	1,453,463	499,684	93,171	54,159	806,449	121,618	151,353	533,478	551,438	347,416
2016	23,142	20,523	1,401,586	471,589	92,157	591	837,249	119,607	163,967	553,675	1,105,113	327,790
2017	19,994	17,874	1,188,550	395,440	87,146	572	705,392	100,729	139,833	464,830	1,569,943	250,174
2018	17,501	15,655	1,017,722	324,646	83,248	555	609,274	87,077	128,708	393,488	1,963,432	192,525
2019	15,497	13,871	877,824	266,547	81,710	38,173	491,394	75,049	114,662	301,683	2,265,115	134,188
2020	9,290	8,361	513,497	144,166	54,023	25,939	289,368	44,505	72,192	172,670	2,437,785	69,821
2021	-	-	-	-	-	-	-	-	-	-	2,437,785	-
2022	-	-	-	-	-	-	-	-	-	-	2,437,785	-
2023	-	-	-	-	-	-	-	-	-	-	2,437,785	-
2024	-	-	-	-	-	-	-	-	-	-	2,437,785	-
2025	-	-	-	-	-	-	-	-	-	-	2,437,785	-
Rem.	-	-	-	-	-	-	-	-	-	-	2,437,785	-
Total	145,802	130,093	8,458,458	2,772,480	659,798	993,541	4,032,639	697,996	896,858	2,437,785		1,281,454

Tenge JV | **Table 6**

Tenge Field - Kazakhstan - Competent Person's Report

Crude Oil Reserves Summary*

Effective December 31, 2010

Age Zone Area	Jurassic 18 A Sand	Jurassic 18 B Sand	Jurassic 18 C Sand	Jurassic 21 East	Jurassic 21 West	Jurassic 22 A Sand	Jurassic 22 B Sand	Jurassic 23 Total	Total Crude Oil Reserves
Porosity, %	17.0	17.5	17.5	15.0	15.0	14.0	14.0	14.0	
Water Saturation, %	35.0	35.0	35.0	40.0	40.0	35.0	35.0	35.0	
Oil Shrinkage, frac	0.78	0.78	0.78	0.81	0.81	0.82	0.82	0.82	
Original Oil-In Place, bbl/ac-ft	665	685	685	562	562	579	579	579	
Area, Acres	9,590	6,949	5,046	1,546	684	4,016	3,784	6,315	
Gross Rock Volume, Acre-ft	292,720	335,710	277,005	319,409	150,815	220,314	149,715	360,547	
Net Rock Volume, Acre-ft	96,102	185,288	89,496	75,700	17,947	79,313	109,292	250,941	
Average Net to Gross, %	33	55	32	24	12	36	73	70	
Average Net Pay, ft.	10.0	26.7	17.7	49.0	26.2	19.7	28.9	39.7	
Original Oil in Place, Mbbl	63,913	126,851	61,271	42,557	10,089	45,896	63,244	145,212	559,034
Proved Producing Reserves									
Proved Producing Area, Acres		396			80			40	
Average PDP Net Pay, ft.		50			22			53	
Original Oil in Place, Mbbl		13,500			1,003			1,216	
Recovery Factor, %		8.8			6.2			2	
Original Recoverable, Mbbl	-	1,189	-	2	62	-	-	30	1,283
Cumulative Recovery, Mbbl	-	828	-	2	30	-	-	30	890
Remaining Recoverable, Mbbl	-	361	-	-	32	-	-	-	393
1P Reserves									
Percentage of Mapped In Place Volume, %		50	50						
Original Oil in Place, Mbbl		63,426	30,635		1,003			1,216	96,280
Recovery Factor, %		10.0	10.0		6.2			2	9.9
Original Recoverable, Mbbl	-	6,343	3,064	2	62	-	-	30	9,500
Cumulative Recovery, Mbbl	-	828	-	2	30	-	-	30	890
Remaining Recoverable, Mbbl	-	5,515	3,064	-	32	-	-	-	8,610
2P Reserves									
Percentage of Mapped In Place Volume, %	100	100	100	50	25	100	100	100	
Original Oil in Place, Mbbl	63,913	126,851	61,271	21,278	2,522	45,896	63,244	145,212	530,188
Recovery Factor, %	4.0	25.0	25.0	20.0	15.0	2.0	2.0	2.0	11.2
Original Recoverable, Mbbl	2,557	31,713	15,318	4,256	378	918	1,265	2,904	59,308
Cumulative Recovery, Mbbl	-	828	-	2	30	-	-	30	890
Remaining Recoverable, Mbbl	2,557	30,885	15,318	4,254	348	918	1,265	2,874	58,418
3P Reserves									
Percentage of Mapped In Place Volume, %	125	125	125	100	100	125	125	125	
Original Oil in Place, Mbbl	79,892	158,564	76,588	42,557	10,089	57,370	79,055	181,515	685,631
Recovery Factor, %	10.0	30.0	30.0	25.0	20.0	5.0	5.0	5.0	15.6
Original Recoverable, Mbbl	7,989	47,569	22,976	10,639	2,018	2,869	3,953	9,076	107,089
Cumulative Recovery, Mbbl	-	828	-	2	30	-	-	30	890
Remaining Recoverable, Mbbl	7,989	46,742	22,976	10,637	1,988	2,869	3,953	9,046	106,199

*Reserves quoted are for the full life of the field and include recovery beyond the contract expiry (Sept. 5, 2020)

Tenge JV

Table 7

Tenge Field - Kazakhstan - Competent Person's Report

Solution Gas Reserves Summary*

Effective December 31, 2010

Age Zone Area	Jurassic 18 A Sand	Jurassic 18 B Sand	Jurassic 18 C Sand	Jurassic 21 East	Jurassic 21 West	Jurassic 22 A Sand	Jurassic 22 B Sand	Jurassic 23 Total	Total Sol'n Gas Reserves
Original Oil in Place, Mbbl	63,913	126,851	61,271	42,557	10,089	45,896	63,244	145,212	559,034
Raw Solution Gas GOR, scf/bbl	555	555	555	555	555	495	495	498	
Original Solution Gas in Place, MMcf	35,496	70,450	34,028	23,632	5,603	22,725	31,315	72,323	295,570
1P Reserves									
Percentage of Mapped In Place Volume, %	-	-	-	-	-	-	-	-	
Original Solution Gas in Place, MMcf	-	-	-	-	-	-	-	-	-
Recovery Factor, %	-	-	-	-	-	-	-	-	-
Original Raw Recoverable, MMcf	-	-	-	-	-	-	-	-	-
Cumulative Raw Recovery, MMcf	-	460	-	1	17	-	-	15	492
Remaining Raw Recoverable, MMcf	-	-	-	-	-	-	-	-	-
Gas Shrinkage, %	-	-	-	-	-	-	-	-	-
Sales Gas Remaining Recoverable, MMcf	-	-	-	-	-	-	-	-	-
2P Reserves									
Percentage of Mapped In Place Volume, %	100	100	100	25	25	100	100	100	
Original Solution Gas in Place, MMcf	35,496	70,450	34,028	5,908	1,401	22,725	31,315	72,323	273,644
Recovery Factor, %	10.0	40.0	40.0	40.0	20.0	35.0	35.0	35.0	33.7
Original Raw Recoverable, MMcf	3,550	28,180	13,611	2,363	280	7,954	10,960	25,313	92,211
Cumulative Raw Recovery, MMcf	-	460	-	1	17	-	-	15	492
Remaining Raw Recoverable, MMcf	3,550	27,720	13,611	2,362	263	7,954	10,960	25,298	91,718
Gas Shrinkage, %	10	10	10	10	10	10	10	10	10
Sales Gas Remaining Recoverable, MMcf	3,195	24,948	12,250	2,126	237	7,158	9,864	22,768	82,546
3P Reserves									
Percentage of Mapped In Place Volume, %	125	125	125	50	50	125	125	125	
Original Solution Gas in Place, MMcf	44,370	88,062	42,535	11,816	2,801	28,406	39,143	90,403	347,537
Recovery Factor, %	20.0	50.0	50.0	50.0	30.0	45.0	45.0	45.0	43.7
Original Raw Recoverable, MMcf	8,874	44,031	21,267	5,908	840	12,783	17,615	40,681	152,000
Cumulative Raw Recovery, MMcf	-	460	-	1	17	-	-	15	492
Remaining Raw Recoverable, MMcf	8,874	43,571	21,267	5,907	824	12,783	17,615	40,666	151,507
Gas Shrinkage, %	10	10	10	10	10	10	10	10	10
Sales Gas Remaining Recoverable, MMcf	7,987	39,214	19,141	5,316	741	11,505	15,853	36,600	136,356

*Reserves quoted are for the full life of the field and include recovery beyond the contract expiry (Sept. 5, 2020)

Tenge JV
Tenge Field - Kazakhstan - Competent Person's Report
Gas Cap Reserves Summary*
Effective December 31, 2010

Table 8

Age **Zone** **Area**	**Jurassic** **18** **A Sand**	**Jurassic** **18** **B Sand**	**Jurassic** **18** **C Sand**	**Jurassic** **21** **East**	**Jurassic** **21** **West**	**Jurassic** **22** **A Sand**	**Jurassic** **22** **B Sand**	**Jurassic** **23** **Total**	**Total** **Gas Cap** **Reserves**
Porosity, %	17.0	17.5	17.5	15.0		14.0	14.0	14.0	
Water Saturation, %	30.0	30.0	30.0	30.0		30.0	30.0	30.0	
Pressure, psia	2,902	2,902	2,902	3,106		3,252	3,252	3,413	
Temperature, deg F	198	198	198	211		214	214	221	
Z-Factor, frac.	0.91	0.91	0.91	0.92		0.93	0.93	0.94	
Original Gas In Place, mcf/ac-ft	892	918	918	817		786	786	808	
Area, Acres	11,867	5,400	2,624	1,072		2,614	2,678	3,523	
Gross Rock Volume, Acre-ft	1,095,473	399,139	175,392	49,448		299,494	145,853	251,902	
Net Rock Volume, Acre-ft	393,049	197,625	37,289	7,959		107,818	106,473	175,324	
Average Net to Gross, %	36	50	21	16		36	73	70	
Average Net Pay, ft.	33.1	36.6	14.2	7.4		41.2	39.8	49.8	
Original Gas in Place, MMcf	350,699	181,518	34,250	6,502		84,781	83,723	141,612	883,085
1P Reserves									
Percentage of Mapped Gas-in Place, %	-	-	-	-		-	-	-	
Original Gas in Place, MMcf	-	-	-	-		-	-	-	-
Recovery Factor, %	-	-	-	-		-	-	-	-
Original Raw Recoverable, MMcf	-	-	-	-		-	-	-	-
Cumulative Raw Recovery, MMcf	-	-	-	-		-	-	-	-
Remaining Raw Recoverable, MMcf	-	-	-	-		-	-	-	-
Gas Shrinkage, %	-	-	-	-		-	-	-	-
Sales Gas Remaining Recoverable, MMcf	-	-	-	-		-	-	-	-
2P Reserves									
Percentage of Mapped Gas-in Place, %	100	100	100	100		100	100	100	
Original Gas in Place, MMcf	350,699	181,518	34,250	6,502		84,781	83,723	141,612	883,085
Recovery Factor, %	70.0	70.0	70.0	70.0		70.0	70.0	70.0	-
Original Raw Recoverable, MMcf	245,489	127,062	23,975	4,552		59,347	58,606	99,128	618,160
Cumulative Raw Recovery, MMcf	-	-	9,866	-		24,812	24,503	41,444	100,626
Remaining Raw Recoverable, MMcf	245,489	127,062	14,109	4,552		34,534	34,104	57,684	517,534
Gas Shrinkage, %	10	10	10	10		10	10	10	-
Sales Gas Remaining Recoverable, MMcf	220,940	114,356	12,698	4,097		31,081	30,693	51,915	465,781
3P Reserves									
Percentage of Mapped Gas-in Place, %	125	125	125	125		125	125	125	
Original Gas in Place, MMcf	438,374	226,897	42,812	8,128		105,976	104,654	177,015	1,103,856
Recovery Factor, %	80.0	80.0	80.0	80.0		80.0	80.0	80.0	-
Original Raw Recoverable, MMcf	350,699	181,518	34,250	6,502		84,781	83,723	141,612	883,085
Cumulative Raw Recovery, MMcf	-	-	9,866	-		24,812	24,503	41,444	100,626
Remaining Raw Recoverable, MMcf	350,699	181,518	24,384	6,502		59,969	59,221	100,167	782,459
Gas Shrinkage, %	10	10	10	10		10	10	10	-
Sales Gas Remaining Recoverable, MMcf	315,629	163,366	21,945	5,852		53,972	53,299	90,150	704,214

*Reserves quoted are for the full life of the field and include recovery beyond the contract expiry (Sept. 5, 2020)

Tenge JV

Table 9

Tenge Field - Kazakhstan - Competent Person's Report
Reservoir and Fluid Properties

Effective December 31, 2010

	Jurassic 18	Jurassic 21	Jurassic 22	Jurassic 23
Imperial Units				
Lithology	SS	SS	SS	SS
Average Net Oil Pay Thickness, ft	39	11	47	40
Oil Pool Area, acres	9,590	8,324	4,016	6,315
Average Net Gas Pay Thickness, ft	73	7	40	50
Gas Pool Area, acres	11,867	1,072	2,678	3,523
Average Oil Column Depth, ft SS	5,906	6,430	6,857	7,054
Average Oil Permeability From Core, md	1 to 50	1 to 50	1 to 50	1 to 50
Initial Reservoir Pressure, atm	197	211	221	232
Initial Reservoir Pressure, psia	2,902	3,106	3,252	3,413
Bubble Point Pressure, atm	197	211	221	232
Bubble Point Pressure, psia	2,902	3,106	3,252	3,413
Reservoir Temperature, F	198	210	214	221
Stock Tank Oil Density, g/cc	0.849	0.846	0.852	0.857
Stock Tank Oil Gravity, degrees API	35	36	35	34
Oil Formation Volume Factor, Bo	1.289	1.242	1.220	1.220
Oil Viscosity* (insitu), cp	0.9	1.1	1.1	1.1
Solution GOR, scf/bbl	555	555	495	498
Oil Sulphur Content, %	0.15	n/a	n/a	n/a
Oil Paraffin Content, %	24	22	22	25
Ashphaltenes, %	10	10	8	8
Gas Compressibility, Z Factor	0.91	0.92	0.93	0.94
Gas Cap Gas Composition, CO2 (mol%)	0.8	n/a	1.3	1.4
Gas Cap Gas Composition, N2 (mol%)	1.6	n/a	0.6	0.1
Gas Cap Gas Composition, H2S (mol%)	-	-	-	-

	Jurassic 18	Jurassic 21	Jurassic 22	Jurassic 23
Metric Units				
Lithology	SS	SS	SS	SS
Average Net Oil Pay Thickness, m	12	3	14	12
Oil Pool Area, ha	3,836	3,330	1,606	2,526
Average Net Gas Pay Thickness, m	22	2	12	15
Gas Pool Area, ha	4,747	429	1,071	1,409
Average Oil Column Depth, m SS	1,800	1,960	2,090	2,150
Average Oil Permeability From Core, md	1 to 50	1 to 50	1 to 50	1 to 50
Initial Reservoir Pressure, kPa	19,900	21,300	22,300	23,400
Bubble Point Pressure, kPa	19,900	21,300	22,300	23,400
Reservoir Temperature, C	92	99	101	105
Stock Tank Oil Density, g/cc	0.849	0.846	0.852	0.857
Oil Formation Volume Factor, Bo	1.289	1.242	1.220	1.220
Oil Viscosity, mPa.s	0.9	1.1	1.1	1.1
Solution GOR, m3/T	116.5	116.9	103.5	103.5
Solution GOR, m3/m3	99	99	88	89
Oil Sulphur Content, %	0.15	n/a	n/a	n/a
Oil Paraffin Content, %	24	22	22	25
Ashphaltenes, %	10	10	8	8
Gas Compressibility, Z Factor	0.91	0.92	0.93	0.94
Gas Cap Gas Composition, CO2 (mol%)	0.8	n/a	1.3	1.4
Gas Cap Gas Composition, N2 (mol%)	1.6	n/a	0.6	0.1
Gas Cap Gas Composition, H2S (mol%)	-	-	-	-

n/a = not available

Tenge JV
Tenge Field - Kazakhstan - Competent Person's Report
Summary of Economic Parameters
Effective December 31, 2010

Price Schedule

McDaniel & Associates December 31, 2010 Forecast Price Case

Pricing Adjustments (2011$ - US)

Product	Price Adjustment
Crude Oil Export Price	Brent less $18.50/bbl

It is assumed that 100 percent of the crude oil can be exported.

Natural Gas Price	See Table 11

Operating Costs (2011$ - US)

Current Operating Costs	
Variable Production Costs ($ / Boe)	3.00
Variable Operating Costs ($ / well/month)	3,000
Fixed Operating Costs ($ / Year)	1,250,000

Operating Costs for 2014+	PDP	1P	2P	3P
Variable Production Costs ($ / Boe)	1.00	2.50	2.00	1.75
Variable Operating Costs ($ / well/month)	1,000	8,000	13,000	18,000
Fixed Operating Costs ($ / Year)	200,000	2,700,000	18,400,000	25,800,000

* Operating Costs transition during 2011 from the 'current operating costs' to the 'operating costs for 2014+'
* Fixed field costs were reduced by 10 percent per year in each of the last three years of the forecast
* Operating Costs include general and administrative costs but exclude pipeline and marketing fees (netted out of price)

Capital Costs (2011$ - US)

See Table 12

Abandonment Costs (2011$ - US)

Total amount based on $50,000 per well

Tenge JV
Tenge Field - Kazakhstan - Competent Person's Report
Summary of Economic Parameters
Effective December 31, 2010

Interests and Fiscal Terms

Tenge JV Working Interest	100 Percent
Crude Oil Customs Export Duty, $/T	40

Mineral Extraction Tax (Incremental Tiers)

	Export Sales			Domestic Sales		
	2011 to 2012	**2013**	**2014+**	**2011 to 2012**	**2013**	**2014+**
Volumes less than 250 MT	5.0%	6.0%	7.0%	2.5%	3.0%	3.5%
From 250 to 500 MT	7.0%	8.0%	9.0%	3.5%	4.0%	4.5%
From 500 to 1,000 MT	8.0%	9.0%	10.0%	4.0%	4.5%	5.0%
From 1,000 to 2,000 MT	9.0%	10.0%	11.0%	4.5%	5.0%	5.5%
From 2,000 to 3,000 MT	10.0%	11.0%	12.0%	5.0%	5.5%	6.0%
From 3,000 to 4,000 MT	11.0%	12.0%	13.0%	5.5%	6.0%	6.5%
From 4,000 to 5,000 MT	12.0%	13.0%	14.0%	6.0%	6.5%	7.0%
From 5,000 to 7,000 MT	13.0%	14.0%	15.0%	6.5%	7.0%	7.5%
From 7,000 to 10,000 MT	15.0%	16.0%	17.0%	7.5%	8.0%	8.5%
Volumes exceeding 10,000 MT	18.0%	19.0%	20.0%	9.0%	9.5%	10.0%

Rent Tax on Exported Crude Oil - Based on World Price which was assumed to be Brent

World Price, $/bbl	Tax Rate
20	0%
30	0%
40	0%
50	7%
60	11%
70	14%
80	16%
90	17%
100	19%
110	21%
120	22%
130	23%
140	25%
150	26%
160	27%
170	29%
180	30%
200	32%

Capital Depreciation Rate – Development Costs	15 Percent Declining Balance
Development Capital Cost Balance at December 31, 2010	$7.424 million
Tax Loss Carryforward Balance at December 31, 2010	$41.675 million
Profit Tax	20.0 percent in 2011 to 2012
	17.5 percent in 2013
	15.0 percent in 2014+

Excess Profits Tax (Incremental Tiers) - Based on Ratio of Accumulated Income to Accumulated Expenses:

Up to 1.25	0 percent
From 1.25 to 1.3	10 percent
From 1.3 to 1.4	20 percent
From 1.4 to 1.5	30 percent
From 1.5 to 1.6	40 percent
From 1.6 to 1.7	50 percent
Above 1.7	60 percent
Property Tax	1.5 Percent
VAT	Not Included

Tenge JV

Table 11

Summary of Price Forecasts

Effective December 31, 2010

Year	Brent Crude Oil Price $US/bbl	Export Price Differential $US/bbl	Export Price $US/bbl	Tenge Gas Price $US/Mcf	Tenge Gas Price $US/E^{3}m^3	Inflation Forecast %
2011	85.00	18.50	**66.50**	**2.49**	88.37	2.00
2012	87.20	18.87	**68.33**	**2.75**	97.60	2.00
2013	89.50	19.25	**70.25**	**3.32**	117.80	2.00
2014	92.30	19.63	**72.67**	**3.74**	132.74	2.00
2015	95.20	20.02	**75.18**	**4.14**	146.91	2.00
2016	98.30	20.43	**77.87**	**4.54**	161.08	2.00
2017	100.30	20.83	**79.47**	**4.81**	170.70	2.00
2018	102.30	21.25	**81.05**	**5.06**	179.74	2.00
2019	104.20	21.68	**82.52**	**5.30**	188.24	2.00
2020	106.40	22.11	**84.29**	**5.53**	196.24	2.00
2021	108.50	22.55	**85.95**	**5.65**	200.69	2.00
2022	110.70	23.00	**87.70**	**5.79**	205.43	2.00
2023	112.80	23.46	**89.34**	**5.92**	210.12	2.00
2024	115.10	23.93	**91.17**	**6.06**	215.09	2.00
2025	117.50	24.41	**93.09**	**6.21**	220.36	2.00
2026	119.85	24.90	**94.95**	**6.35**	225.48	2.00
2027	122.25	25.40	**96.85**	**6.50**	230.70	2.00
2028	124.69	25.90	**98.79**	**6.65**	236.02	2.00
2029	127.19	26.42	**100.76**	**6.80**	241.45	2.00
2030	129.73	26.95	**102.78**	**6.96**	246.99	2.00
Thereafter	+2.0%	+2.0%	+2.0%			2.00

Pricing Assumptions :

Brent and inflation forecasts based on the McDaniel & Associates December 31, 2010 price forecast.

The export price differential accounts for the differential at the point of sale as well as the cost of transportation and marketing fees to get the oil from the wellhead to the point of sale.

All production is exported and sold at the export price

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Proved Producing Reserves

Year	Horizontal Oil Prodn #	Horizontal Water Inj. #	Horizontal 2011 US$M	Vertical Oil Prodn #	Vertical Gas Prodn #	Vertical Gas Inj. #	Vertical 2011 US$M	Well Conversions #	Well Conversions 2011 US$M	Pipeline & Facilities 2011 US$M	Capitalized Maint. 2011 US$M	Total Area 2011 US$M	Total Area Future US$M
2011	-	-	-	-	-	-	-	-	-	-	40	40	40
2012	-	-	-	-	-	-	-	-	-	-	40	40	41
2013	-	-	-	-	-	-	-	-	-	-	40	40	42
2014	-	-	-	-	-	-	-	-	-	-	40	40	42
2015	-	-	-	-	-	-	-	-	-	-	40	40	43
2016	-	-	-	-	-	-	-	-	-	-	40	40	44
2017	-	-	-	-	-	-	-	-	-	-	-	-	-
2018	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	-	-	-	-	-	240	240	252
Average Well Cost			5,500				3,400		100				

Total Proved Reserves

Year	Horizontal Oil Prodn #	Horizontal Water Inj. #	Horizontal 2011 US$M	Vertical Oil Prodn #	Vertical Gas Prodn #	Vertical Gas Inj. #	Vertical 2011 US$M	Well Conversions #	Well Conversions 2011 US$M	Pipeline & Facilities 2011 US$M	Capitalized Maint. 2011 US$M	Total Area 2011 US$M	Total Area Future US$M
2011	-	-	-	2	-	-	6,800	-	-	5,752	50	12,602	12,602
2012	7	-	38,500	-	-	5	17,000	-	-	14,380	95	69,975	71,375
2013	5	5	55,000	-	-	-	-	-	-	8,628	155	63,783	66,360
2014	4	-	22,000	-	-	-	-	-	-	-	200	22,200	23,559
2015	-	-	-	-	-	-	-	-	-	-	200	200	216
2016	-	-	-	-	-	-	-	-	-	-	200	200	221
2017	-	-	-	-	-	-	-	-	-	-	200	200	225
2018	-	-	-	-	-	-	-	-	-	-	-	-	-
2019	-	-	-	-	-	-	-	-	-	-	-	-	-
2020	-	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	16	5	115,500	2	-	5	23,800	-	-	28,761	1,100	169,161	174,558
Average Well Cost			5,500				3,400		100				

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Total Proved + Probable Reserves

	Horizontal			Vertical						Pipeline &	Capitalized	Total	Total
Year	Oil Prodn #	Water Inj. #	2011 US$M	Oil Prodn #	Gas Prodn #	Gas Inj. #	2011 US$M	Well Conversions #	2011 US$M	Facilities 2011 US$M	Maint. 2011 US$M	Area 2011 US$M	Area Future US$M
2011	-	-	-	1	3	-	13,600	-	-	34,815	60	48,475	48,475
2012	7	-	38,500	2	8	6	54,400	-	-	128,163	125	221,188	225,611
2013	14	6	110,000	1	11	4	54,400	3	300	107,056	215	271,971	282,958
2014	14	6	110,000	-	6	2	27,200	-	-	-	360	137,560	145,980
2015	2	-	11,000	-	-	-	-	-	-	-	440	11,440	12,383
2016	-	-	-	-	-	-	-	-	-	-	450	450	497
2017	-	-	-	-	-	-	-	-	-	20,562	428	20,990	23,638
2018	-	-	-	-	-	-	-	5	500	20,562	406	21,468	24,660
2019	-	-	-	-	-	-	-	5	500	-	386	886	1,038
2020	-	-	-	-	-	-	-	-	-	-	367	367	438
2021	-	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	37	12	269,500	4	28	12	149,600	13	1,300	311,158	3,236	734,794	765,679
Average Well Cost			5,500				3,400		100				

Total Proved + Probable + Possible Reserves

	Horizontal			Vertical						Pipeline &	Capitalized	Total	Total
Year	Oil Prodn #	Water Inj. #	2011 US$M	Oil Prodn #	Gas Prodn #	Gas Inj. #	2011 US$M	Well Conversions #	2011 US$M	Facilities 2011 US$M	Maint. 2011 US$M	Area 2011 US$M	Area Future US$M
2011	-	-	-	1	3	-	13,600	-	-	52,903	60	66,563	66,563
2012	7	-	38,500	2	8	6	54,400	-	-	195,301	125	288,326	294,092
2013	14	6	110,000	4	8	4	54,400	3	300	163,412	230	328,342	341,607
2014	14	6	110,000	4	7	4	51,000	-	-	-	410	161,410	171,290
2015	7	2	49,500	-	-	-	-	-	-	-	535	50,035	54,159
2016	-	-	-	-	-	-	-	-	-	-	535	535	591
2017	-	-	-	-	-	-	-	-	-	-	508	508	572
2018	-	-	-	-	-	-	-	-	-	-	483	483	555
2019	-	-	-	-	-	-	-	6	600	31,521	459	32,580	38,173
2020	-	-	-	-	-	-	-	6	600	31,521	436	32,557	38,909
2021	-	-	-	-	-	-	-	-	-	-	414	414	505
2022	-	-	-	-	-	-	-	-	-	-	393	393	489
2023	-	-	-	-	-	-	-	-	-	-	374	374	474
2024	-	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	-	-	-	-
2029	-	-	-	-	-	-	-	-	-	-	-	-	-
2030	-	-	-	-	-	-	-	-	-	-	-	-	-
2031	-	-	-	-	-	-	-	-	-	-	-	-	-
2032	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	42	14	308,000	11	26	14	173,400	15	1,500	474,658	4,961	962,520	1,007,978
Average Well Cost			5,500				3,400		100				
	42	14	308,000	37		14							

* In both the 2P and 3P cases the 3 vertical gas producers drilled in 2011 will intially produce from the 18b and 21 oil rims before being converted to 18a gas producers in 2013

Table 13

Tenge JV
Tenge Field - Kazakhstan - Competent Person's Report
Summary of Reserves and Net Present Values to End of Field Life
Effective December 31, 2010

Summary of Reserves (1)

Reserve Category	Crude Oil Reserves - bbls Property Gross Mbbl	Company Gross Mbbl	Company Net Mbbl	Crude Oil Reserves - Tonnes Property Gross MT	Company Gross MT	Company Net MT
Proved Developed Producing Reserves	393	393	369	53	53	50
Proved Undeveloped Reserves	8,217	8,217	7,669	1,109	1,109	1,035
Total Proved Reserves	8,610	8,610	8,038	1,162	1,162	1,085
Probable Reserves	49,808	49,808	44,537	6,726	6,726	6,014
Proved Plus Probable Reserves	58,418	58,418	52,575	7,888	7,888	7,099
Possible Reserves	47,781	47,781	41,985	6,456	6,456	5,673
Proved Plus Probable Plus Possible Reserves	106,199	106,199	94,560	14,344	14,344	12,772

Reserve Category	Natural Gas Reserves - scf Property Gross MMcf	Company Gross MMcf	Company Net MMcf	Barrels of Oil Equivalent Property Gross Mboe	Company Gross Mboe	Company Net Mboe
Proved Developed Producing Reserves	-	-	-	393	393	369
Proved Undeveloped Reserves	-	-	-	8,217	8,217	7,669
Total Proved Reserves	-	-	-	8,610	8,610	8,038
Probable Reserves	545,501	545,501	490,951	140,725	140,725	126,363
Proved Plus Probable Reserves	545,501	545,501	490,951	149,335	149,335	134,400
Possible Reserves	292,776	292,776	263,498	96,577	96,577	85,901
Proved Plus Probable Plus Possible Reserves	838,277	838,277	754,449	245,912	245,912	220,302

Summary of Company Share of Net Present Values Before Income Taxes

	$M US Dollars				
Reserve Category	0.0%	5.0%	10.0%	15.0%	20.0%
Proved Developed Producing Reserves	14,384	12,132	10,432	9,119	8,084
Proved Undeveloped Reserves	175,674	126,309	90,862	64,976	45,793
Total Proved Reserves	190,058	138,441	101,294	74,095	53,878
Probable Reserves	3,958,104	2,414,494	1,586,099	1,099,452	792,141
Proved Plus Probable Reserves	4,148,163	2,552,935	1,687,394	1,173,547	846,018
Possible Reserves	3,084,566	1,980,115	1,339,360	943,199	685,314
Proved Plus Probable Plus Possible Reserves	7,232,729	4,533,050	3,026,754	2,116,746	1,531,332

Summary of Company Share of Net Present Values After Income Taxes

	$M US Dollars				
Reserve Category	0.0%	5.0%	10.0%	15.0%	20.0%
Proved Developed Producing Reserves	13,844	11,673	10,035	8,769	7,771
Proved Undeveloped Reserves	123,148	84,361	56,846	37,016	22,535
Total Proved Reserves	136,991	96,034	66,880	45,785	30,306
Probable Reserves	2,098,719	1,318,998	876,054	604,181	427,156
Proved Plus Probable Reserves	2,235,710	1,415,032	942,934	649,966	457,462
Possible Reserves	1,779,980	1,146,909	773,558	540,367	387,677
Proved Plus Probable Plus Possible Reserves	4,015,690	2,561,941	1,716,492	1,190,333	845,139

(1) Company Gross reserves are based on Company working interest share of the reserves.
Company Net reserves are based on Company working interest share of reserves after royalties.

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Table 14

Tenge Field - Kazakhstan - Competent Person's Report

Forecast of Prod. and Revenues to End of Field Life - For Illustrative Purposes Only

Proved Developed Producing Reserves

Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

		Crude Oil					Natural Gas				Total	Total
Year	Producing Well Count	Daily Rate Bopd	Annual Volume Mbbl	Annual Volume MT	Crude Oil Price US$/bbl	Sales Revenue US$M	Daily Rate Mcfpd	Annual Volume MMcf	Nat Gas Price US$/Mcf	Sales Revenue US$M	Oil&Gas BOE Mbbl	Sales Revenue US$M
2011	4	218	80	11	66.50	5,295	-	-	-	-	80	5,295
2012	4	183	67	9	68.33	4,566	-	-	-	-	67	4,566
2013	4	154	56	8	70.25	3,939	-	-	-	-	56	3,939
2014	4	129	47	6	72.67	3,419	-	-	-	-	47	3,419
2015	4	108	39	5	75.18	2,968	-	-	-	-	39	2,968
2016	4	91	33	4	77.87	2,579	-	-	-	-	33	2,579
2017	4	76	28	4	79.47	2,209	-	-	-	-	28	2,209
2018	4	64	23	3	81.05	1,890	-	-	-	-	23	1,890
2019	3	54	20	3	82.52	1,615	-	-	-	-	20	1,615
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.		-	-	-	-	-	-	-	-	-	-	-
Total			393	53	72.50	28,479		-	-	-	393	28,479

Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	430	265	5.0	900	1,633	20.51	-	40	2,028	103	-	1,924
2012	361	228	5.0	776	846	12.66	-	41	2,313	88	-	2,225
2013	303	236	6.0	670	316	5.64	-	42	2,372	76	-	2,297
2014	254	239	7.0	650	313	6.66	-	42	1,920	65	-	1,856
2015	213	208	7.0	564	311	7.88	-	43	1,628	56	-	1,573
2016	179	181	7.0	490	310	9.37	-	44	1,375	48	-	1,328
2017	150	155	7.0	464	280	10.08	-	-	1,160	41	-	1,119
2018	126	132	7.0	397	250	10.74	-	-	985	35	-	950
2019	106	113	7.0	339	221	11.28	234	-	602	30	-	572
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	2,120	1,757	6.2	5,249	4,481	11.41	234	252	14,384	541	-	13,844

Company Working Interest Share of Production and Revenues Before and After tax

Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	80	76	5,295	1,595	1,633	40	2,028	103	-	1,924	1,924	1,835
2012	67	63	4,566	1,365	846	41	2,313	88	-	2,225	4,150	1,929
2013	56	53	3,939	1,209	316	42	2,372	76	-	2,297	6,446	1,810
2014	47	44	3,419	1,143	313	42	1,920	65	-	1,856	8,302	1,329
2015	39	37	2,968	985	311	43	1,628	56	-	1,573	9,875	1,024
2016	33	31	2,579	849	310	44	1,375	48	-	1,328	11,202	786
2017	28	26	2,209	768	280	-	1,160	41	-	1,119	12,321	602
2018	23	22	1,890	655	250	-	985	35	-	950	13,271	465
2019	20	18	1,615	558	221	234	602	30	-	572	13,844	255
2020	-	-	-	-	-	-	-	-	-	-	13,844	-
2021	-	-	-	-	-	-	-	-	-	-	13,844	-
2022	-	-	-	-	-	-	-	-	-	-	13,844	-
2023	-	-	-	-	-	-	-	-	-	-	13,844	-
2024	-	-	-	-	-	-	-	-	-	-	13,844	-
2025	-	-	-	-	-	-	-	-	-	-	13,844	-
Rem.	-	-	-	-	-	-	-	-	-	-	13,844	-
Total	393	369	28,479	9,127	4,481	487	14,384	541	-	13,844		10,035

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Table 15

Tenge Field - Kazakhstan - Competent Person's Report

Forecast of Prod. and Revenues to End of Field Life - For Illustrative Purposes Only

Total Proved Reserves

Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

		Crude Oil					Natural Gas				Total	Total
Year	Producing Well Count	Daily Rate Bopd	Annual Volume Mbbl	Annual Volume MT	Crude Oil Price US$/bbl	Sales Revenue US$M	Daily Rate Mcfpd	Annual Volume MMcf	Nat Gas Price US$/Mcf	Sales Revenue US$M	Oil&Gas BOE Mbbl	Sales Revenue US$M
2011	5	328	120	16	66.50	7,965	-	-	-	-	120	7,965
2012	10	1,800	657	89	68.33	44,898	-	-	-	-	657	44,898
2013	16	4,112	1,501	203	70.25	105,432	-	-	-	-	1,501	105,432
2014	20	4,951	1,807	244	72.67	131,312	-	-	-	-	1,807	131,312
2015	20	4,453	1,625	219	75.18	122,188	-	-	-	-	1,625	122,188
2016	20	3,055	1,115	151	77.87	86,835	-	-	-	-	1,115	86,835
2017	20	2,101	767	104	79.47	60,937	-	-	-	-	767	60,937
2018	19	1,449	529	71	81.05	42,874	-	-	-	-	529	42,874
2019	18	910	332	45	82.52	27,409	-	-	-	-	332	27,409
2020	17	430	157	21	84.29	13,244	-	-	-	-	157	13,244
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.		-	-	-	-	-	-	-	-	-	-	-
Total			8,610	1,162	74.69	643,094		-	-	-	8,610	643,094

Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	647	398	5.0	1,354	2,039	17.03	-	12,602	(9,075)	183	-	(9,259)
2012	3,548	2,245	5.0	7,633	4,836	7.36	-	71,375	(44,738)	691	-	(45,429)
2013	8,103	6,326	6.0	17,923	8,261	5.50	-	66,360	(1,541)	3,868	-	(5,409)
2014	9,756	9,192	7.0	24,949	9,697	5.37	-	23,559	54,159	9,968	5,247	38,944
2015	8,776	8,553	7.0	23,216	9,399	5.78	-	216	72,027	9,524	5,750	56,754
2016	6,020	6,078	7.0	16,499	8,179	7.33	-	221	49,838	6,391	2,611	40,837
2017	4,140	4,266	7.0	12,797	7,362	9.60	-	225	32,148	3,903	476	27,768
2018	2,856	3,001	7.0	9,003	6,196	11.71	-	-	21,817	2,464	-	19,353
2019	1,793	1,919	7.0	5,756	5,128	15.44	-	-	12,813	1,234	-	11,579
2020	848	927	7.0	2,781	4,105	26.13	1,972	-	2,610	758	-	1,853
2021	-	-	-	-	-	-	-	-	-	-	-	-
2022	-	-	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-	-	-
Rem.	-	-	-	-	-	-	-	-	-	-	-	-
Total	46,487	42,905	6.7	121,911	65,202	7.57	1,972	174,558	190,058	38,983	14,084	136,991

Company Working Interest Share of Production and Revenues Before and After tax

Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	120	114	7,965	2,399	2,039	12,602	(9,075)	183	-	(9,259)	(9,259)	(8,828)
2012	657	624	44,898	13,425	4,836	71,375	(44,738)	691	-	(45,429)	(54,688)	(39,377)
2013	1,501	1,411	105,432	32,352	8,261	66,360	(1,541)	3,868	-	(5,409)	(60,097)	(4,262)
2014	1,807	1,681	131,312	43,897	9,697	23,559	54,159	9,968	5,247	38,944	(21,153)	27,897
2015	1,625	1,512	122,188	40,544	9,399	216	72,027	9,524	5,750	56,754	35,601	36,960
2016	1,115	1,037	86,835	28,597	8,179	221	49,838	6,391	2,611	40,837	76,438	24,176
2017	767	713	60,937	21,203	7,362	225	32,148	3,903	476	27,768	104,206	14,945
2018	529	492	42,874	14,861	6,196	-	21,817	2,464	-	19,353	123,559	9,469
2019	332	309	27,409	9,468	5,128	-	12,813	1,234	-	11,579	135,138	5,150
2020	157	146	13,244	4,557	4,105	1,972	2,610	758	-	1,853	136,991	749
2021	-	-	-	-	-	-	-	-	-	-	136,991	-
2022	-	-	-	-	-	-	-	-	-	-	136,991	-
2023	-	-	-	-	-	-	-	-	-	-	136,991	-
2024	-	-	-	-	-	-	-	-	-	-	136,991	-
2025	-	-	-	-	-	-	-	-	-	-	136,991	-
Rem.	-	-	-	-	-	-	-	-	-	-	136,991	-
Total	8,610	8,038	643,094	211,304	65,202	176,530	190,058	38,983	14,084	136,991		66,880

Tenge JV

Table 16

Tenge Field - Kazakhstan - Competent Person's Report
Forecast of Prod. and Revenues to End of Field Life - For Illustrative Purposes Only
Total Proved + Probable Reserves
Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

		Crude Oil					Natural Gas				Total	Total
Year	Producing Well Count	Daily Rate Bopd	Annual Volume Mbbl	Annual Volume MT	Crude Oil Price US$/bbl	Sales Revenue US$M	Daily Rate Mcfpd	Annual Volume MMcf	Nat Gas Price US$/Mcf	Sales Revenue US$M	Oil&Gas BOE Mbbl	Sales Revenue US$M
2011	6	416	152	20	66.50	10,089	-	-	-	-	152	10,089
2012	13	5,075	1,852	250	68.33	126,578	-	-	-	-	1,852	126,578
2013	38	17,074	6,232	841	70.25	437,825	40,000	14,600	3.32	48,446	8,665	486,272
2014	61	27,606	10,076	1,360	72.67	732,209	80,000	29,200	3.74	109,186	14,943	841,395
2015	72	28,868	10,537	1,423	75.18	792,094	80,000	29,200	4.14	120,838	15,403	912,932
2016	73	22,925	8,368	1,130	77.87	651,633	80,000	29,200	4.54	132,493	13,234	784,126
2017	71	17,467	6,375	861	79.47	506,628	80,000	29,200	4.81	140,407	11,242	647,035
2018	74	13,329	4,865	657	81.05	394,304	80,000	29,200	5.06	147,840	9,732	542,144
2019	77	10,058	3,671	496	82.52	302,950	80,000	29,200	5.30	154,834	8,538	457,784
2020	75	7,694	2,808	379	84.29	236,707	80,000	29,200	5.53	161,412	7,675	398,119
2021	73	5,896	2,152	291	85.95	184,972	80,000	29,200	5.65	165,072	7,019	350,045
2022	71	2,637	962	130	87.70	84,400	80,000	29,200	5.79	168,975	5,829	253,375
2023	69	1,006	367	50	89.34	32,803	80,000	29,200	5.92	172,828	5,234	205,631
2024	38	-	-	-	-	-	80,000	29,200	6.06	176,921	4,867	176,921
2025	38	-	-	-	-	-	80,000	29,200	6.21	181,253	4,867	181,253
Rem.		-	-	-	-	-	38,040	180,501	6.80	1,226,909	30,084	1,226,909
Total			58,418	7,888	76.91	4,493,192		545,501	5.70	3,107,413	149,335	7,600,606

Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	819	504	5.0	1,715	5,031	33.16	-	48,475	(46,456)	412	-	(46,868)
2012	9,999	6,329	5.0	21,518	18,647	10.07	-	225,611	(155,526)	2,098	-	(157,624)
2013	33,654	44,249	9.1	74,430	43,342	5.00	-	282,958	7,639	37,782	16,318	(46,462)
2014	54,417	91,462	10.9	139,120	61,340	4.10	-	145,980	349,077	67,077	64,428	217,572
2015	56,903	99,214	10.9	150,498	65,421	4.25	-	12,383	528,514	75,610	85,719	367,185
2016	45,191	84,929	10.8	123,810	62,112	4.69	-	497	467,587	65,575	80,290	321,721
2017	34,433	64,703	10.0	106,392	58,472	5.20	-	23,638	359,397	53,112	62,984	243,300
2018	26,277	54,214	10.0	82,804	56,684	5.82	-	24,660	297,504	44,340	53,665	199,499
2019	19,830	42,749	9.3	63,620	55,563	6.51	-	1,038	274,985	38,133	51,583	185,269
2020	15,170	37,445	9.4	49,708	54,252	7.07	-	438	241,105	33,449	49,743	157,913
2021	11,627	33,155	9.5	38,844	49,761	7.09	-	-	216,657	30,136	49,805	136,716
2022	5,204	22,806	9.0	18,568	43,827	7.52	-	-	162,970	22,437	42,237	98,296
2023	1,990	19,579	9.5	7,217	39,225	7.49	-	-	137,620	18,936	40,548	78,136
2024	-	17,692	10.0	-	12,591	2.59	-	-	146,637	23,723	68,883	54,031
2025	-	18,125	10.0	-	12,843	2.64	-	-	150,285	24,270	70,624	55,390
Rem.	-	122,691	10.0	-	86,026	2.86	8,025	-	1,010,167	170,531	468,002	371,635
Total	315,513	759,846	10.0	878,244	725,136	4.86	8,025	765,679	4,148,163	707,624	1,204,829	2,235,710

Company Working Interest Share of Production and Revenues Before and After tax

Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	152	144	10,089	3,038	5,031	48,475	(46,456)	412	-	(46,868)	(46,868)	(44,687)
2012	1,852	1,760	126,578	37,846	18,647	225,611	(155,526)	2,098	-	(157,624)	(204,492)	(136,626)
2013	8,665	7,861	486,272	152,333	43,342	282,958	7,639	37,782	16,318	(46,462)	(250,953)	(36,611)
2014	14,943	13,348	841,395	284,998	61,340	145,980	349,077	67,077	64,428	217,572	(33,382)	155,858
2015	15,403	13,758	912,932	306,615	65,421	12,383	528,514	75,610	85,719	367,185	333,803	239,121
2016	13,234	11,827	784,126	253,930	62,112	497	467,587	65,575	80,290	321,721	655,525	190,467
2017	11,242	10,118	647,035	205,528	58,472	23,638	359,397	53,112	62,984	243,300	898,825	130,945
2018	9,732	8,758	542,144	163,296	56,684	24,660	297,504	44,340	53,665	199,499	1,098,324	97,610
2019	8,538	7,721	457,784	126,198	55,563	1,038	274,985	38,133	51,583	185,269	1,283,593	82,407
2020	7,675	6,935	398,119	102,324	54,252	438	241,105	33,449	49,743	157,913	1,441,506	63,854
2021	7,019	6,338	350,045	83,626	49,761	-	216,657	30,136	49,805	136,716	1,578,222	50,257
2022	5,829	5,275	253,375	46,577	43,827	-	162,970	22,437	42,237	98,296	1,676,518	32,849
2023	5,234	4,721	205,631	28,785	39,225	-	137,620	18,936	40,548	78,136	1,754,655	23,738
2024	4,867	4,380	176,921	17,692	12,591	-	146,637	23,723	68,883	54,031	1,808,685	14,922
2025	4,867	4,380	181,253	18,125	12,843	-	150,285	24,270	70,624	55,390	1,864,076	13,907
Rem.	30,084	27,075	1,226,909	122,691	86,026	8,025	1,010,167	170,531	468,002	371,635	2,235,710	64,922
Total	149,335	134,400	7,600,606	1,953,603	725,136	773,704	4,148,163	707,624	1,204,829	2,235,710		942,934

Tenge JV

Table 17

Tenge Field - Kazakhstan - Competent Person's Report
Forecast of Prod. and Revenues to End of Field Life - For Illustrative Purposes Only
Total Proved + Probable + Possible Reserves
Effective December 31, 2010

Property Gross Share of Production and Gross Revenues

Year	Producing Well Count	Crude Oil Daily Rate Bopd	Crude Oil Annual Volume Mbbl	Crude Oil Annual Volume MT	Crude Oil Price US$/bbl	Crude Oil Sales Revenue US$M	Natural Gas Daily Rate Mcfpd	Natural Gas Annual Volume MMcf	Nat Gas Price US$/Mcf	Natural Gas Sales Revenue US$M	Total Oil&Gas BOE Mbbl	Total Sales Revenue US$M
2011	6	416	152	20	66.50	10,089	-	-	-	-	152	10,089
2012	13	5,075	1,852	250	68.33	126,578	-	-	-	-	1,852	126,578
2013	38	21,375	7,802	1,054	70.25	548,105	52,000	18,980	3.32	62,980	10,965	611,085
2014	64	40,742	14,871	2,009	72.67	1,080,638	130,000	47,450	3.74	177,427	22,779	1,258,065
2015	80	45,815	16,722	2,259	75.18	1,257,102	130,000	47,450	4.14	196,362	24,631	1,453,463
2016	80	41,735	15,233	2,058	77.87	1,186,286	130,000	47,450	4.54	215,300	23,142	1,401,586
2017	77	33,111	12,086	1,632	79.47	960,389	130,000	47,450	4.81	228,161	19,994	1,188,550
2018	74	26,281	9,593	1,296	81.05	777,482	130,000	47,450	5.06	240,240	17,501	1,017,722
2019	78	20,790	7,588	1,025	82.52	626,219	130,000	47,450	5.30	251,605	15,497	877,824
2020	82	16,510	6,026	814	84.29	507,950	130,000	47,450	5.53	262,295	13,934	770,245
2021	79	13,117	4,788	647	85.95	411,483	130,000	47,450	5.65	268,243	12,696	679,726
2022	77	10,425	3,805	514	87.70	333,691	130,000	47,450	5.79	274,585	11,713	608,276
2023	75	8,255	3,013	407	89.34	269,179	130,000	47,450	5.92	280,845	10,921	550,024
2024	73	4,519	1,649	223	91.17	150,371	130,000	47,450	6.06	287,496	9,558	437,867
2025	72	2,261	825	111	93.09	76,839	130,000	47,450	6.21	294,536	8,734	371,375
Rem.		177	193	26	94.95	18,352	48,903	249,897	6.75	1,687,984	41,843	1,706,335
Total			106,199	14,344	78.54	8,340,751		838,277	5.64	4,728,058	245,912	13,068,810

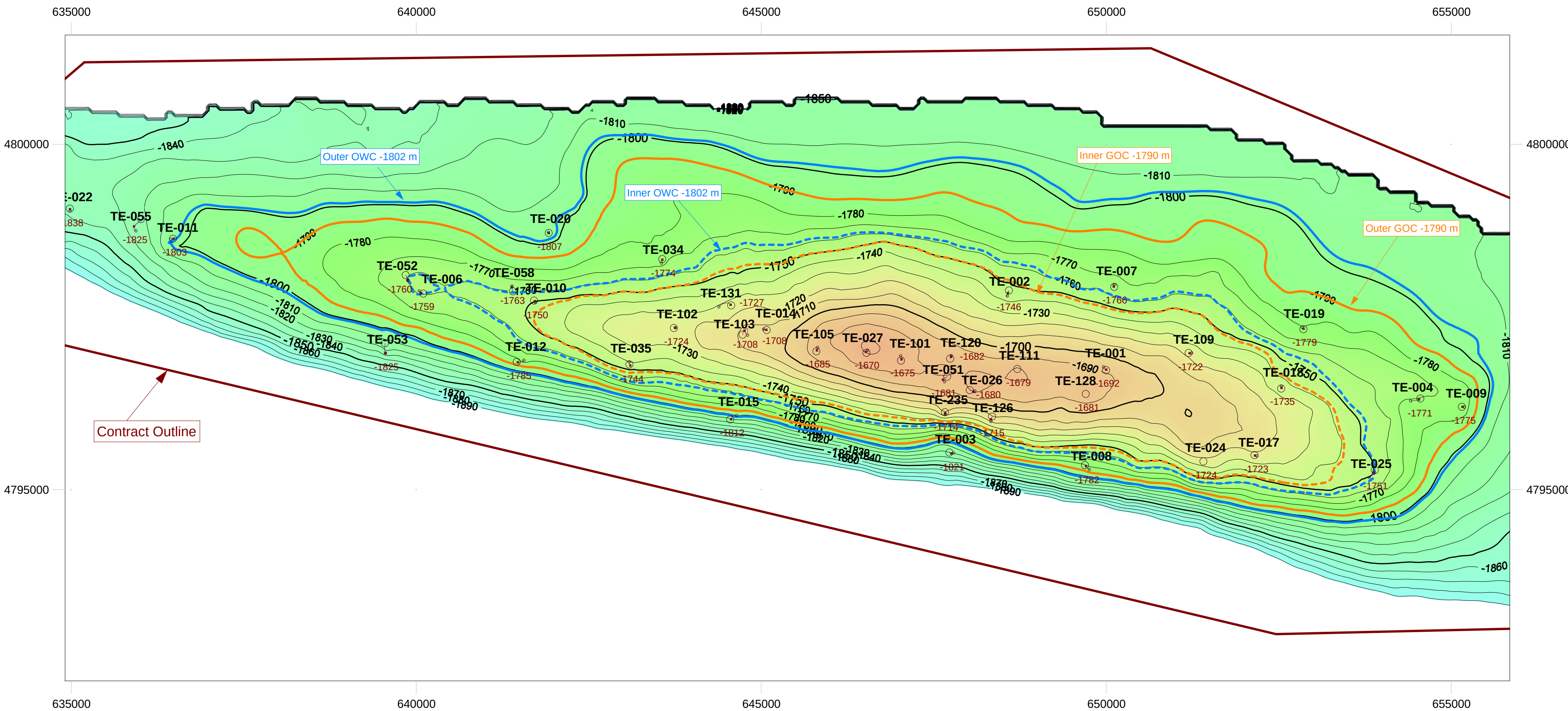
Property Gross Share of Royalties, Expenses and Net Revenues Before and After Tax

Year	Customs Duty US$M	M.E.T. US$M	M.E.T. %	Export Rent Tax US$M	Operating Costs US$M	Operating Costs US$/boe	Aband. Costs US$M	Capital Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M
2011	819	504	5.0	1,715	6,031	39.75	-	66,563	(65,544)	527	-	(66,071)
2012	9,996	6,329	5.0	21,518	22,727	12.27	-	294,092	(228,085)	2,747	-	(230,832)
2013	42,144	61,109	10.0	93,178	55,346	5.05	-	341,607	17,701	43,822	14,828	(40,949)
2014	80,355	147,419	11.7	205,321	84,238	3.70	-	171,290	569,441	102,314	111,316	355,812
2015	90,346	170,488	11.7	238,849	93,171	3.78	-	54,159	806,449	121,618	151,353	533,478
2016	82,311	163,884	11.7	225,394	92,157	3.98	-	591	837,249	119,607	163,967	553,675
2017	65,299	128,459	10.8	201,682	87,146	4.36	-	572	705,392	100,729	139,833	464,830
2018	51,828	109,547	10.8	163,271	83,248	4.76	-	555	609,274	87,077	128,708	393,488
2019	40,997	94,045	10.7	131,506	81,710	5.27	-	38,173	491,394	75,049	114,662	301,683
2020	32,556	77,024	10.0	106,669	81,034	5.82	-	38,909	434,052	66,758	108,288	259,006
2021	25,863	67,973	10.0	86,411	79,439	6.26	-	505	419,535	59,650	102,985	256,900
2022	20,554	60,828	10.0	73,412	78,334	6.69	-	489	374,659	53,414	97,054	224,191
2023	16,276	52,311	9.5	59,219	77,604	7.11	-	474	344,140	49,257	97,289	197,594
2024	8,901	39,276	9.0	33,082	70,156	7.34	-	-	286,453	40,901	91,237	154,315
2025	4,454	34,832	9.4	16,905	63,753	7.30	-	-	251,431	35,958	87,975	127,498
Rem.	1,043	170,083	10.0	4,037	142,642	3.41	9,343	-	1,379,187	222,015	626,102	531,071
Total	573,741	1,384,110	10.6	1,662,171	1,198,738	4.87	9,343	1,007,978	7,232,729	1,181,443	2,035,596	4,015,690

Company Working Interest Share of Production and Revenues Before and After tax

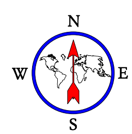
Year	Gross Annual BOE Production Mboe	Net Annual BOE Production Mboe	Total Sales Revenue US$M	M.E.T. & Export Duty & Rent Tax US$M	Operating Costs US$M	Capital & Aband. Costs US$M	Net Cash Flow B. Tax US$M	Property & Corp. Tax US$M	Excess Profit Tax US$M	Net Cash Flow A. Tax US$M	Cum Cash Flow A.T. US$M	NPV A.T. at 10.0% US$M
2011	152	144	10,089	3,038	6,031	66,563	(65,544)	527	-	(66,071)	(66,071)	(62,996)
2012	1,852	1,760	126,578	37,843	22,727	294,092	(228,085)	2,747	-	(230,832)	(296,903)	(200,082)
2013	10,965	9,869	611,085	196,431	55,346	341,607	17,701	43,822	14,828	(40,949)	(337,852)	(32,267)
2014	22,779	20,204	1,258,065	433,096	84,238	171,290	569,441	102,314	111,316	355,812	17,960	254,886
2015	24,631	21,833	1,453,463	499,684	93,171	54,159	806,449	121,618	151,353	533,478	551,438	347,416
2016	23,142	20,523	1,401,586	471,589	92,157	591	837,249	119,607	163,967	553,675	1,105,113	327,790
2017	19,994	17,874	1,188,550	395,440	87,146	572	705,392	100,729	139,833	464,830	1,569,943	250,174
2018	17,501	15,655	1,017,722	324,646	83,248	555	609,274	87,077	128,708	393,488	1,963,432	192,525
2019	15,497	13,871	877,824	266,547	81,710	38,173	491,394	75,049	114,662	301,683	2,265,115	134,188
2020	13,934	12,541	770,245	216,250	81,034	38,909	434,052	66,758	108,288	259,006	2,524,121	104,732
2021	12,696	11,426	679,726	180,247	79,439	505	419,535	59,650	102,985	256,900	2,781,021	94,437
2022	11,713	10,542	608,276	154,794	78,334	489	374,659	53,414	97,054	224,191	3,005,212	74,921
2023	10,921	9,859	550,024	127,806	77,604	474	344,140	49,257	97,289	197,594	3,202,806	60,030
2024	9,558	8,651	437,867	81,258	70,156	-	286,453	40,901	91,237	154,315	3,357,122	42,619
2025	8,734	7,885	371,375	56,191	63,753	-	251,431	35,958	87,975	127,498	3,484,620	32,012
Rem.	41,843	37,664	1,706,335	175,163	142,642	9,343	1,379,187	222,015	626,102	531,071	4,015,690	96,109
Total	245,912	220,302	13,068,810	3,620,023	1,198,738	1,017,321	7,232,729	1,181,443	2,035,596	4,015,690		1,716,492

Figure 1



Legend

OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
○ - Drilled well



2 0 2 4 km

McDaniel
& Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
18a Sand

<mba>	Units – meters	4 May, 2011

Figure 2

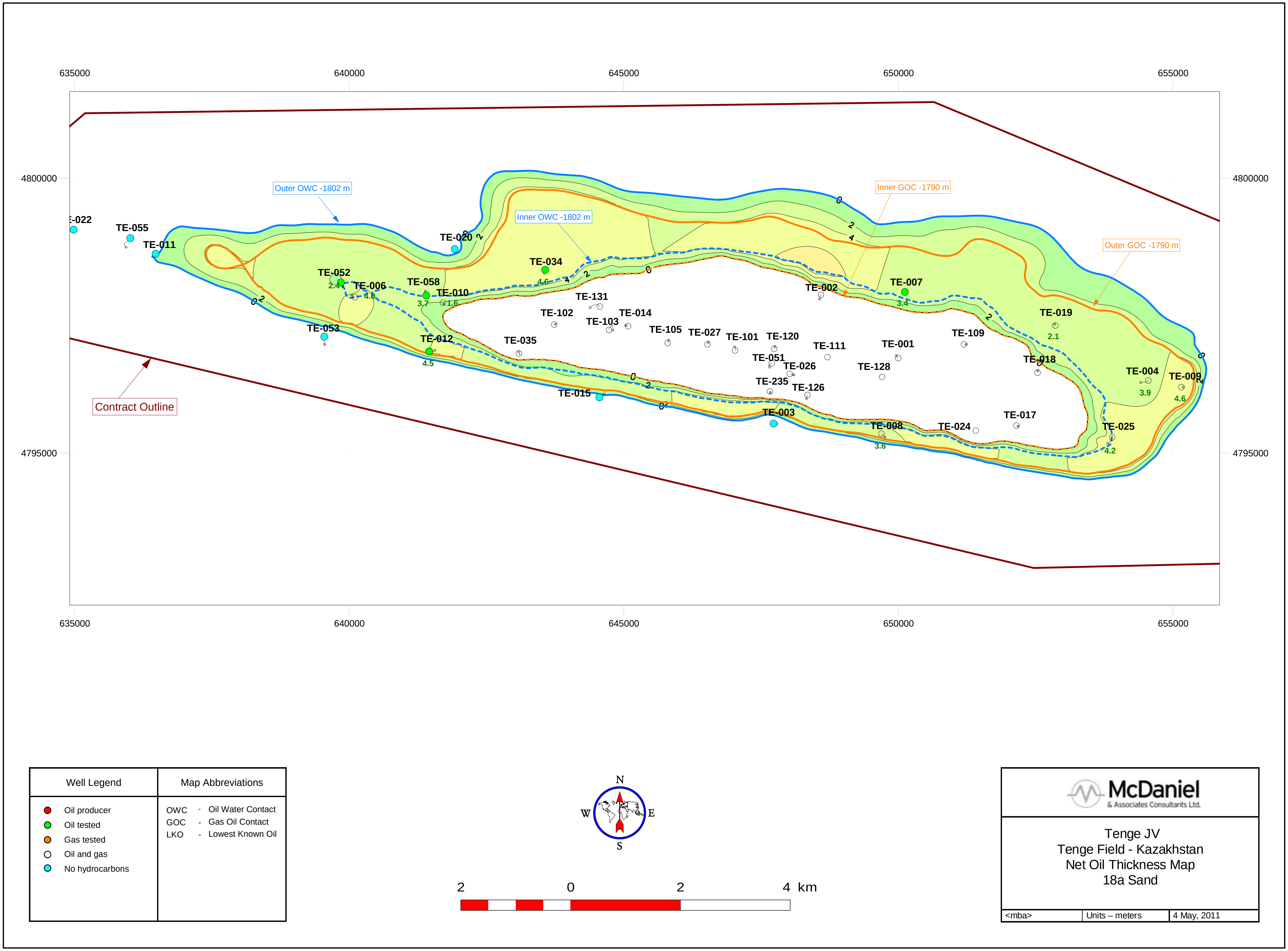
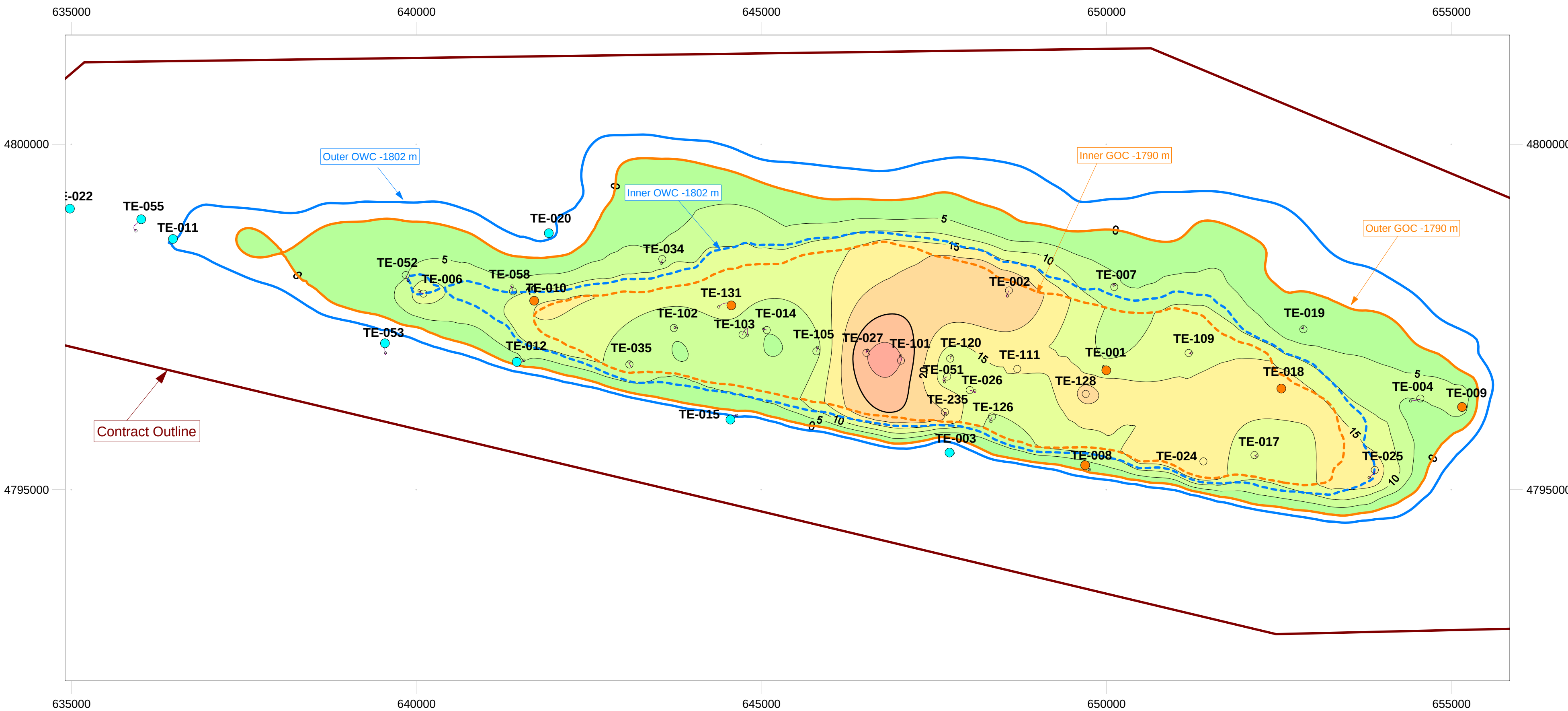
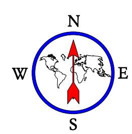
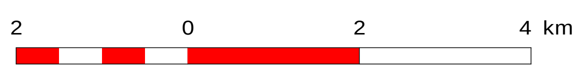

635000
640000
645000
650000
655000
4800000
4795000
Outer OWC -1802 m
Inner OWC -1802 m
Inner GOC -1790 m
Outer GOC -1790 m
Contract Outline
TE-022
TE-055
TE-011
TE-020
TE-052
TE-006
TE-058
TE-010
TE-034
TE-131
TE-102
TE-103
TE-014
TE-053
TE-012
TE-035
TE-105
TE-027
TE-101
TE-120
TE-111
TE-001
TE-109
TE-002
TE-007
TE-019
TE-051
TE-026
TE-128
TE-235
TE-126
TE-018
TE-004
TE-009
TE-015
TE-003
TE-008
TE-024
TE-017
TE-025
2.4
4.0
3.7
1.6
4.6
4.5
3.4
2.1
3.9
4.6
3.6
4.2
Well Legend
Oil producer
Oil tested
Gas tested
Oil and gas
No hydrocarbons
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
N
W
E
S
2 0 2 4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Net Oil Thickness Map
18a Sand
<mba>
Units – meters
4 May, 2011

Figure 3



Well Legend	Map Abbreviations
Oil producer Oil tested Gas tested Oil and gas No hydrocarbons	OWC - Oil Water Contact GOC - Gas Oil Contact LKO - Lowest Known Oil



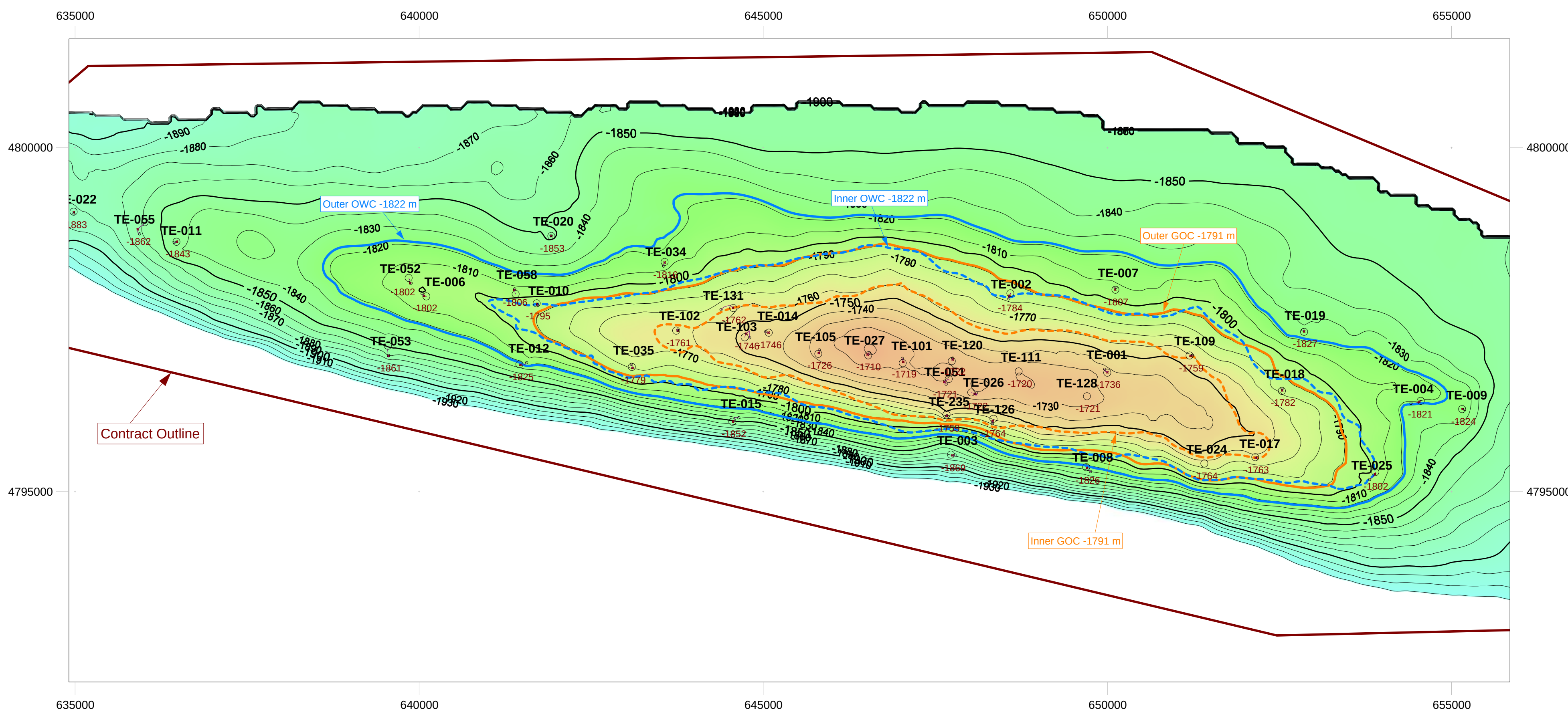


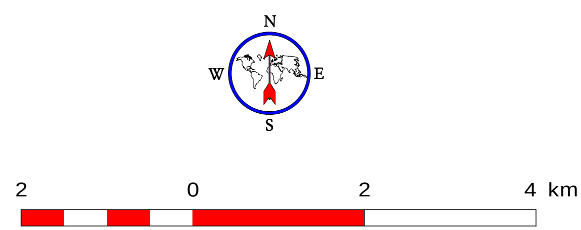
McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Gas Thickness Map
18a Sand

<mba>	Units – meters	4 May, 2011

Figure 4





Legend

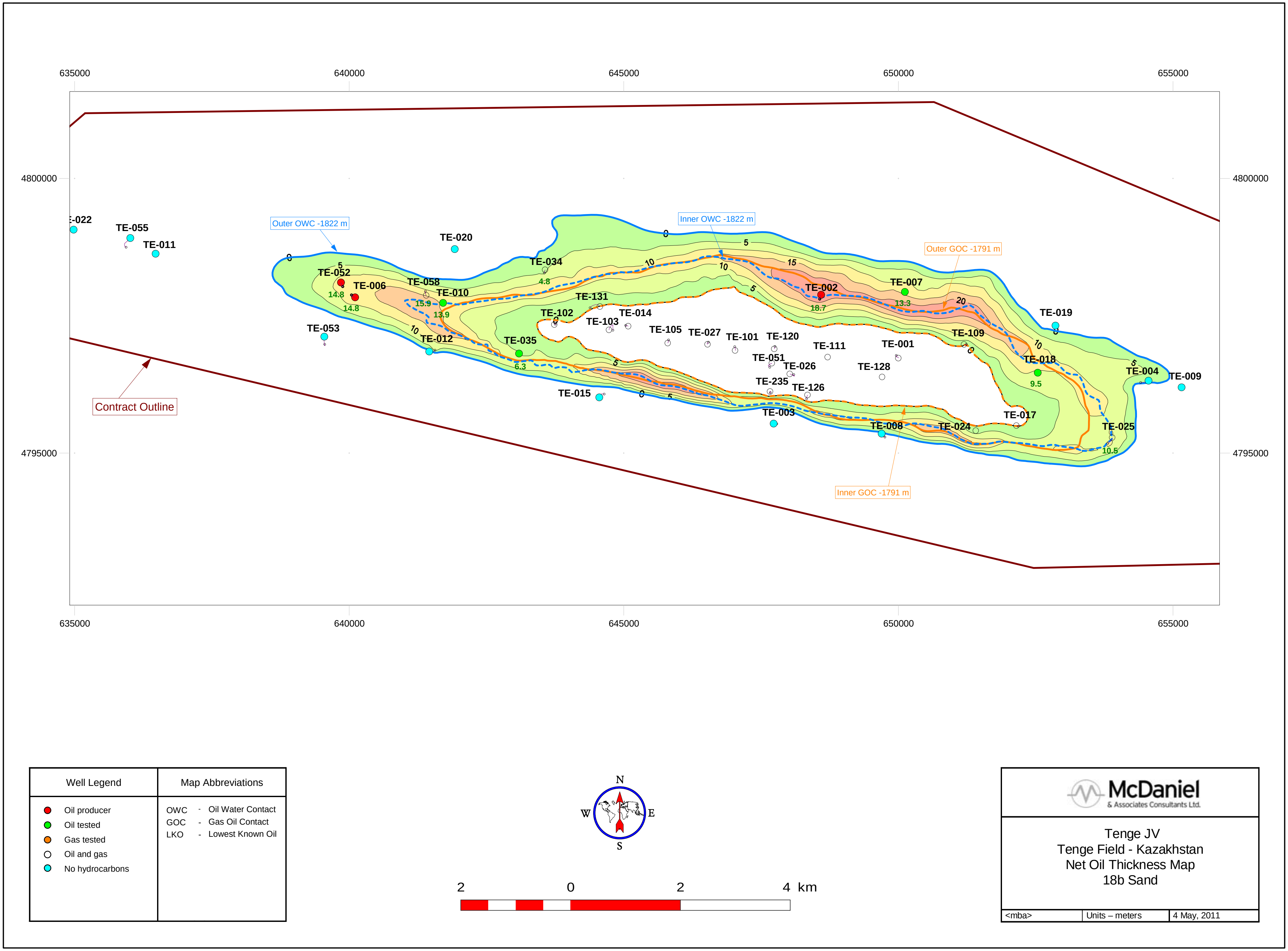
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
O - Drilled well

McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
18b Sand

<mba>	Units – meters	4 May, 2011

Figure 5



635000
640000
645000
650000
655000
4800000
4795000
Outer OWC -1822 m
Inner OWC -1822 m
Outer GOC -1791 m
Inner GOC -1791 m
Contract Outline
TE-055
TE-011
TE-020
TE-034
TE-052
TE-006
TE-058
TE-010
TE-131
TE-102
TE-103
TE-014
TE-053
TE-012
TE-035
TE-105
TE-027
TE-101
TE-120
TE-002
TE-007
TE-019
TE-109
TE-111
TE-001
TE-051
TE-026
TE-128
TE-018
TE-004
TE-009
TE-235
TE-126
TE-015
TE-003
TE-008
TE-024
TE-017
TE-025
14.8
15.9
13.9
4.8
6.3
18.7
13.3
9.5
10.5
Well Legend
Oil producer
Oil tested
Gas tested
Oil and gas
No hydrocarbons
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
N
W
E
S
2 0 2 4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Net Oil Thickness Map
18b Sand
<mba>
Units – meters
4 May, 2011

Figure 6

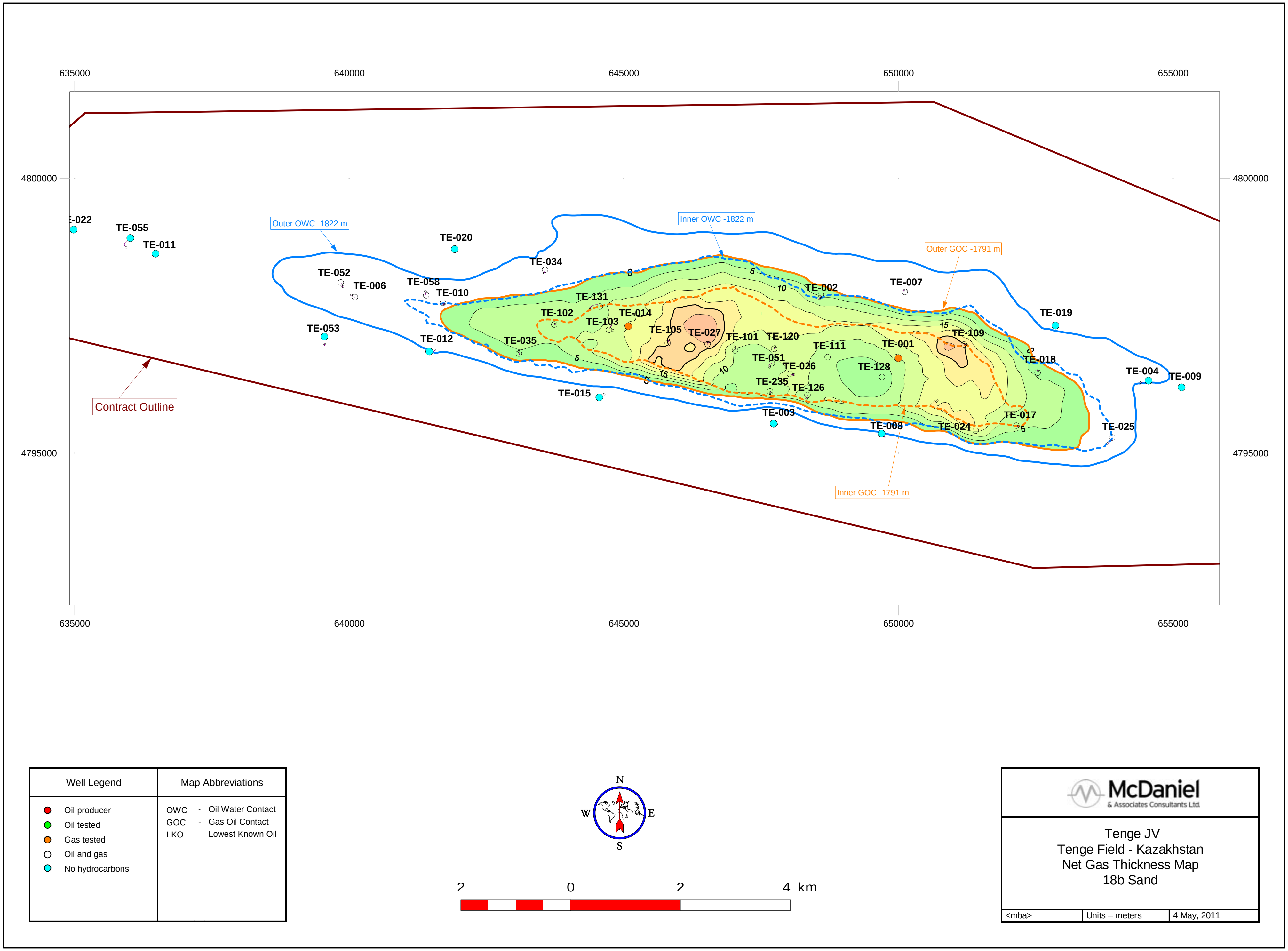
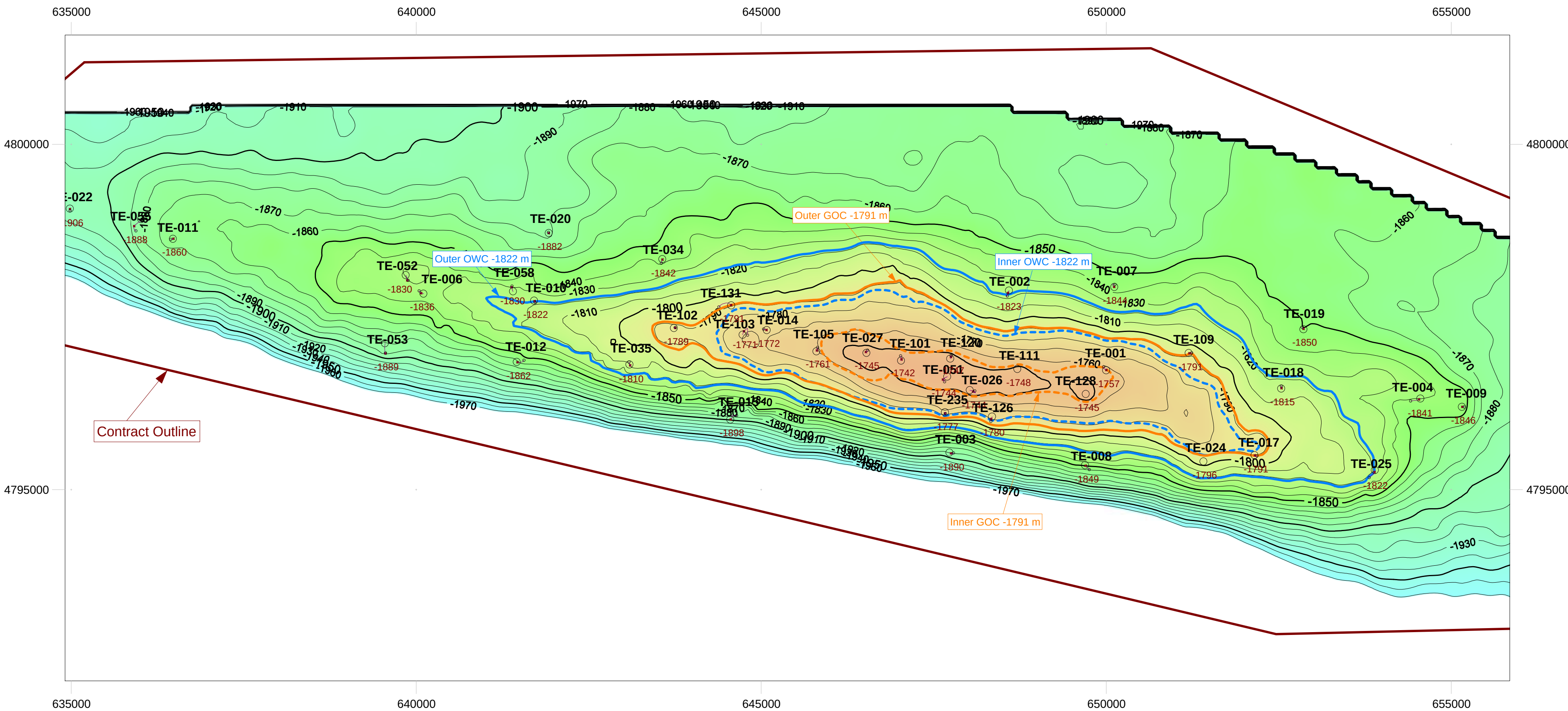
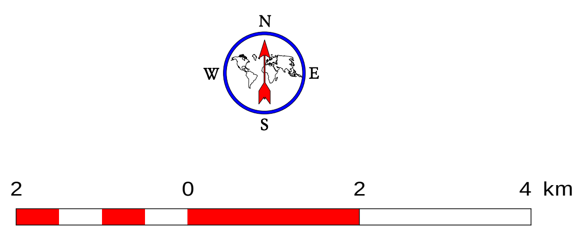

635000
640000
645000
650000
655000
4800000
4795000
Outer OWC -1822 m
Inner OWC -1822 m
Outer GOC -1791 m
Inner GOC -1791 m
Contract Outline
TE-055
TE-011
TE-020
TE-034
TE-052
TE-006
TE-058
TE-010
TE-053
TE-012
TE-131
TE-102
TE-103
TE-014
TE-035
TE-105
TE-027
TE-101
TE-120
TE-002
TE-007
TE-019
TE-109
TE-111
TE-001
TE-051
TE-026
TE-128
TE-018
TE-004
TE-009
TE-235
TE-126
TE-015
TE-003
TE-008
TE-024
TE-017
TE-025
0
5
10
15
Well Legend
Oil producer
Oil tested
Gas tested
Oil and gas
No hydrocarbons
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
N
W
E
S
2
0
2
4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Net Gas Thickness Map
18b Sand
<mba>
Units – meters
4 May, 2011

Figure 7



Legend		
OWC	-	Oil Water Contact
GOC	-	Gas Oil Contact
LKO	-	Lowest Known Oil
O	-	Drilled well

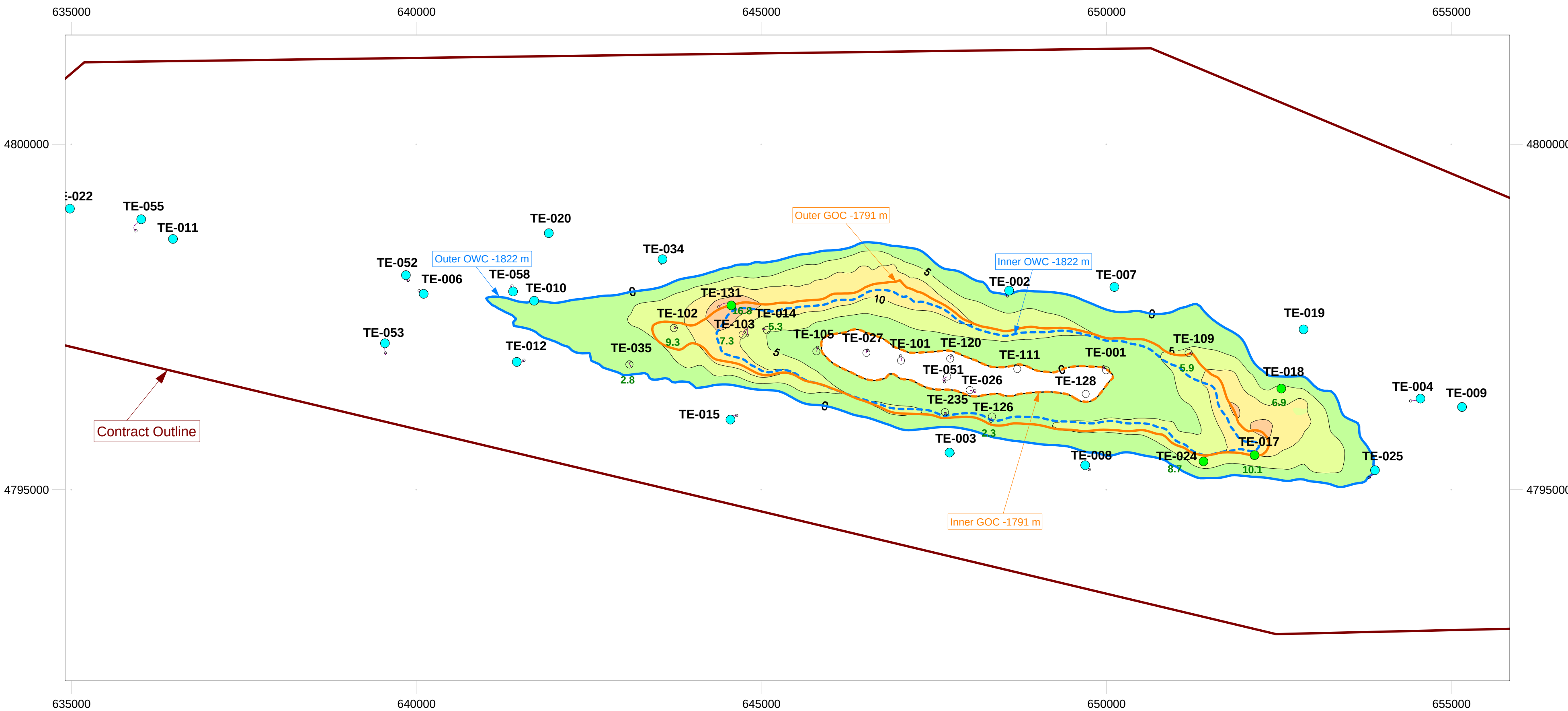


McDaniel & Associates Consultants Ltd.

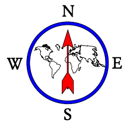
Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
18c Sand

<mba>	Units – meters	4 May, 2011

Figure 8



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil tested	GOC - Gas Oil Contact
Gas tested	LKO - Lowest Known Oil
Oil and gas	
No hydrocarbons	



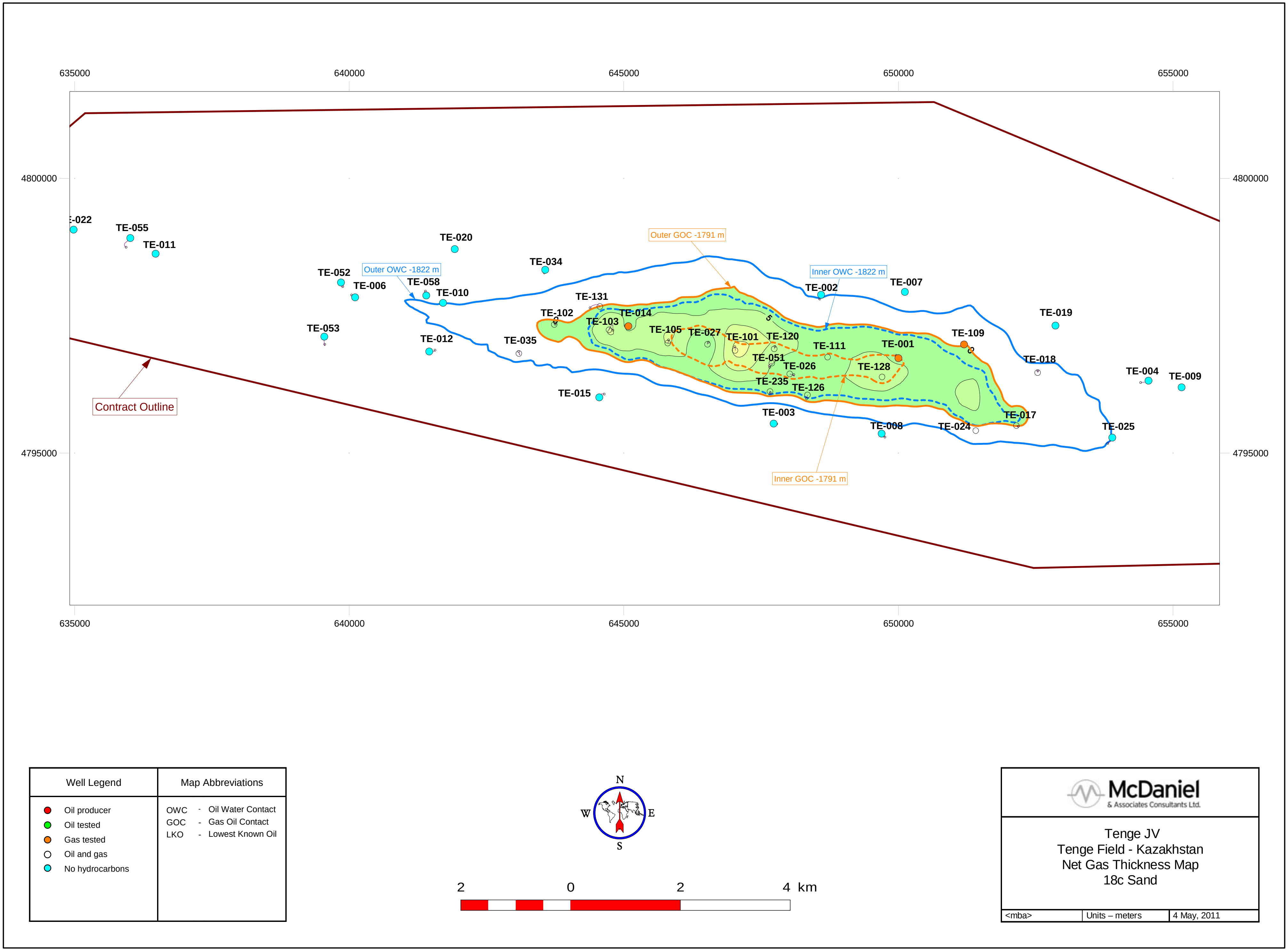
2 0 2 4 km

McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Oil Thickness Map
18c Sand

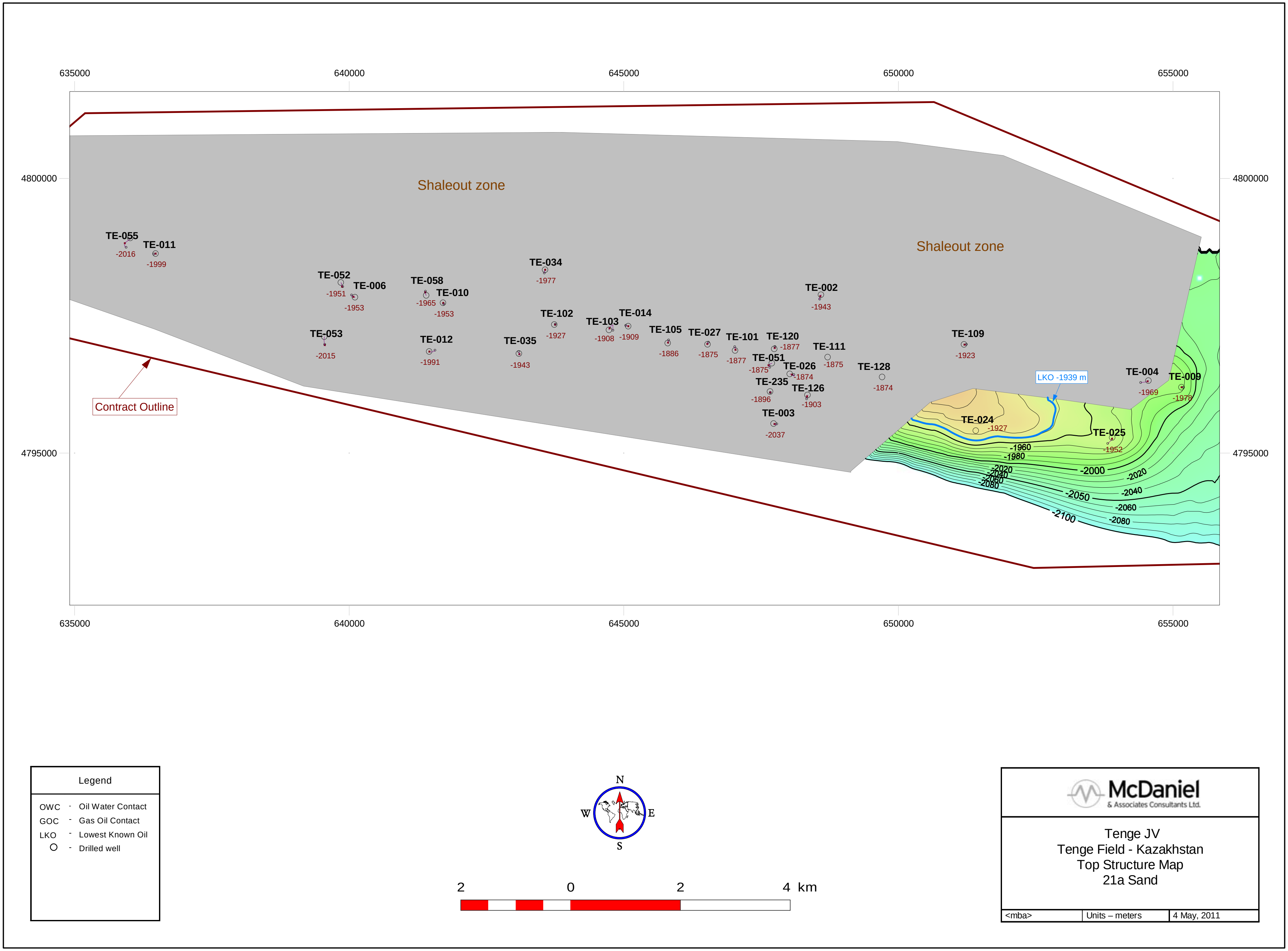
<mba>	Units – meters	4 May, 2011

Figure 9



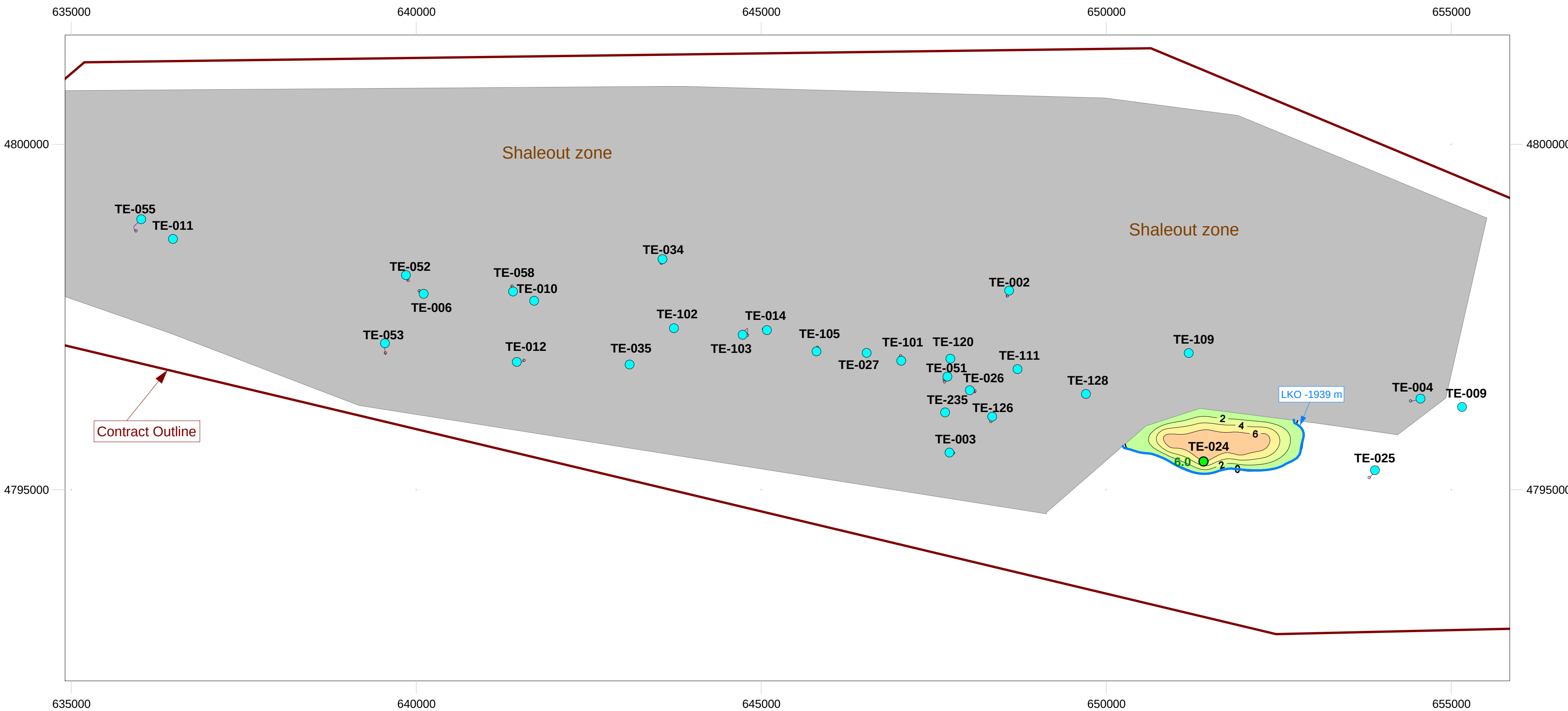
635000
640000
645000
650000
655000
4800000
4795000
Contract Outline
Outer OWC -1822 m
Inner OWC -1822 m
Outer GOC -1791 m
Inner GOC -1791 m
TE-055
TE-011
TE-020
TE-034
TE-052
TE-006
TE-058
TE-010
TE-053
TE-012
TE-035
TE-131
TE-102
TE-103
TE-014
TE-105
TE-027
TE-101
TE-120
TE-051
TE-026
TE-235
TE-126
TE-111
TE-001
TE-128
TE-002
TE-007
TE-109
TE-019
TE-018
TE-004
TE-009
TE-017
TE-024
TE-025
TE-008
TE-003
TE-015
Well Legend
Oil producer
Oil tested
Gas tested
Oil and gas
No hydrocarbons
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
N
W
E
S
2 0 2 4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Net Gas Thickness Map
18c Sand
<mba>
Units – meters
4 May, 2011

Figure 10

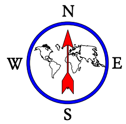


635000
640000
645000
650000
655000
4800000
4795000
Shaleout zone
Shaleout zone
Contract Outline
TE-055
-2016
TE-011
-1999
TE-052
-1951
TE-006
-1953
TE-058
-1965
TE-010
-1953
TE-034
-1977
TE-053
-2015
TE-012
-1991
TE-035
-1943
TE-102
-1927
TE-103
-1908
TE-014
-1909
TE-105
-1886
TE-027
-1875
TE-101
-1877
TE-120
-1877
TE-002
-1943
TE-051
-1875
TE-111
-1875
TE-026
-1874
TE-235
-1896
TE-126
-1903
TE-003
-2037
TE-128
-1874
TE-109
-1923
LKO -1939 m
TE-004
-1969
TE-009
-1978
TE-024
-1927
TE-025
-1952
-1960
-1980
-2000
-2020
-2040
-2050
-2060
-2080
-2100
Legend
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
Drilled well
N
W
E
S
2
0
2
4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
21a Sand
<mba>
Units – meters
4 May, 2011

Figure 11



Well Legend	Map Abbreviations
Oil producer Oil tested Gas tested Oil and gas No hydrocarbons	OWC - Oil Water Contact GOC - Gas Oil Contact LKO - Lowest Known Oil

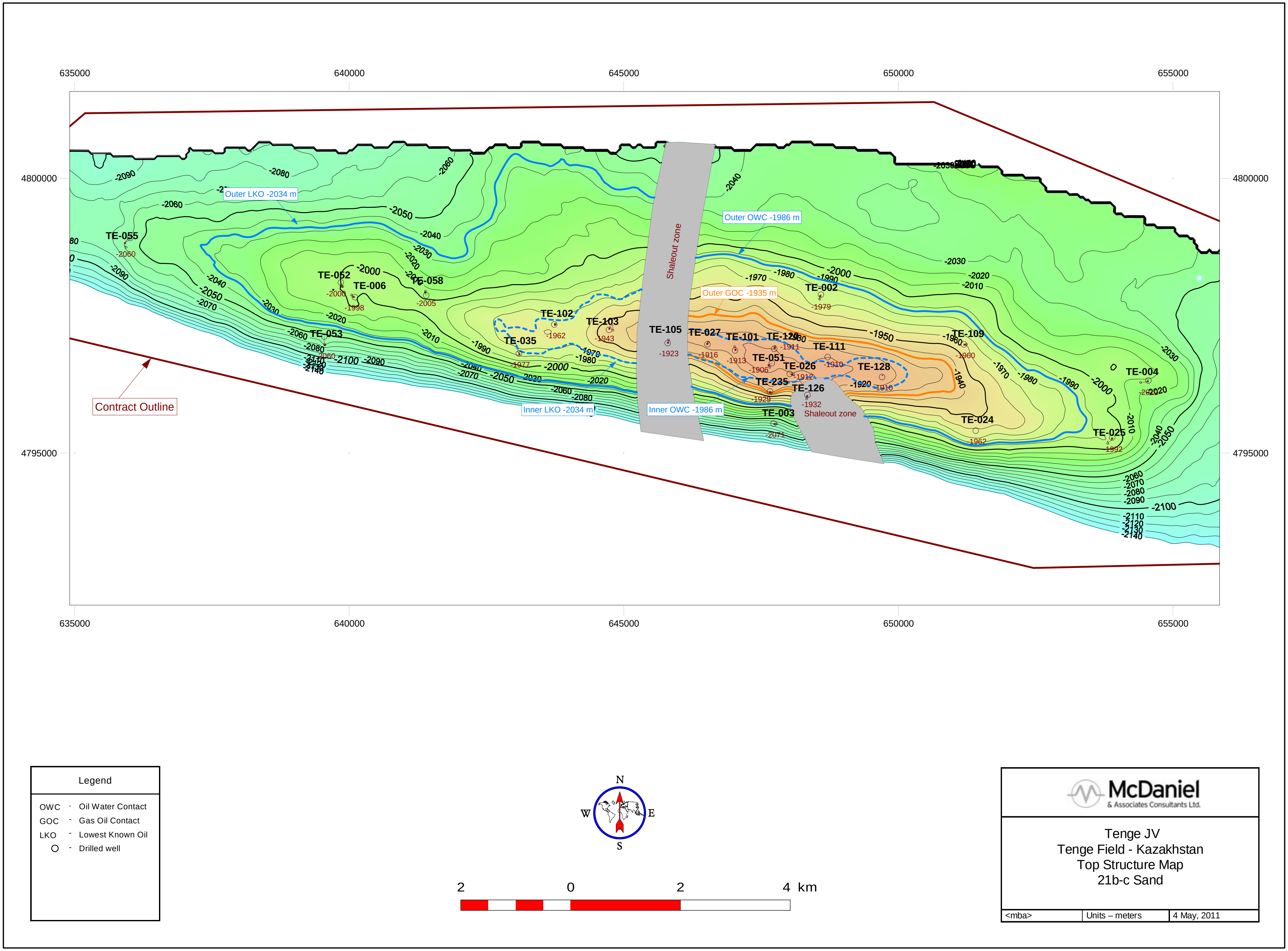


McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Oil Thickness Map
21a Sand

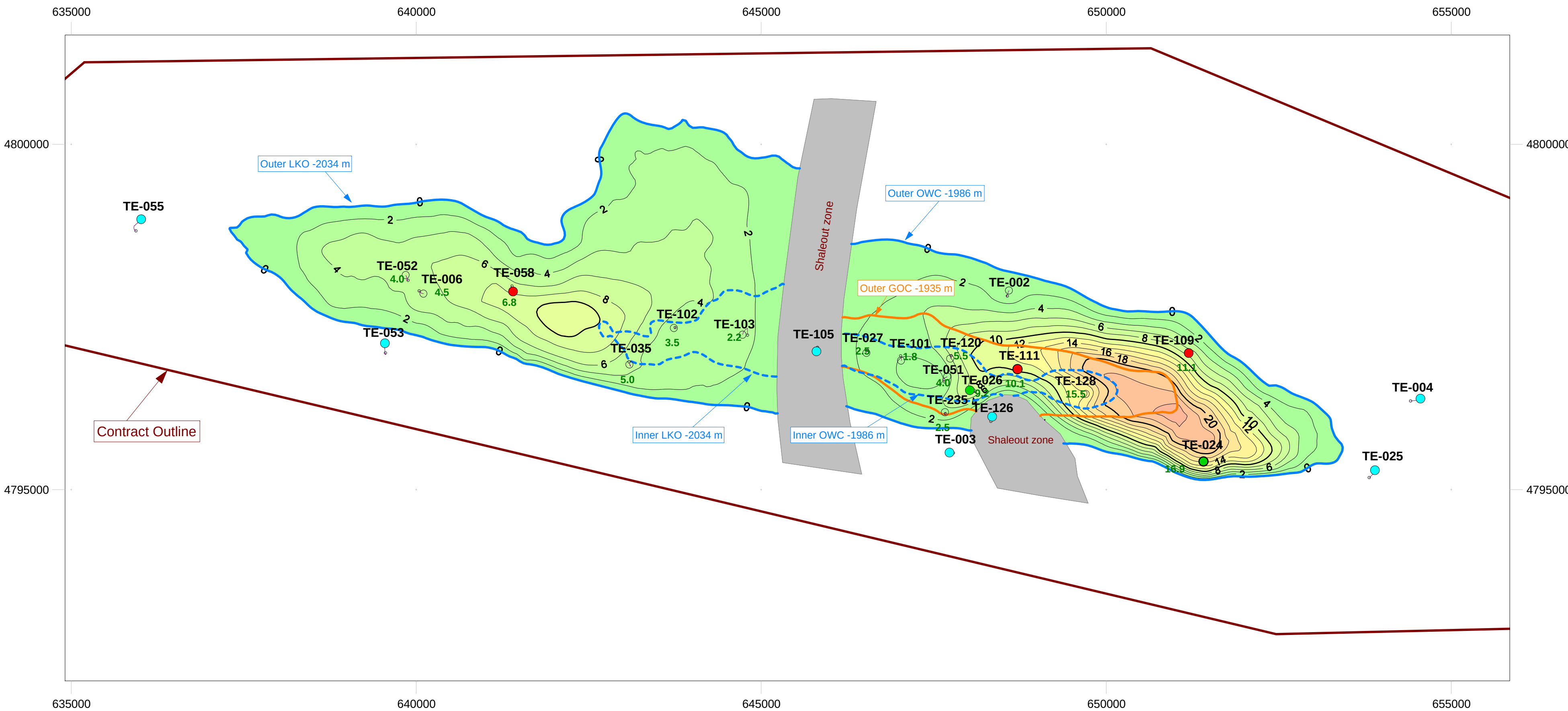
<mba>	Units – meters	4 May, 2011

Figure 12

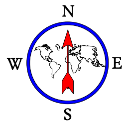


635000
640000
645000
650000
655000
4800000
4795000
Outer LKO -2034 m
Outer OWC -1986 m
Outer GOC -1935 m
Inner LKO -2034 m
Inner OWC -1986 m
Shaleout zone
Shaleout zone
Contract Outline
TE-055
TE-052
TE-006
TE-058
TE-053
TE-035
TE-102
TE-103
TE-105
TE-027
TE-101
TE-051
TE-026
TE-235
TE-126
TE-003
TE-111
TE-128
TE-002
TE-109
TE-024
TE-004
TE-025
Legend
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
Drilled well
N
W
E
S
2
0
2
4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
21b-c Sand
<mba>
Units – meters
4 May, 2011

Figure 13



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil tested	GOC - Gas Oil Contact
Gas tested	LKO - Lowest Known Oil
Oil and gas	
No hydrocarbons	

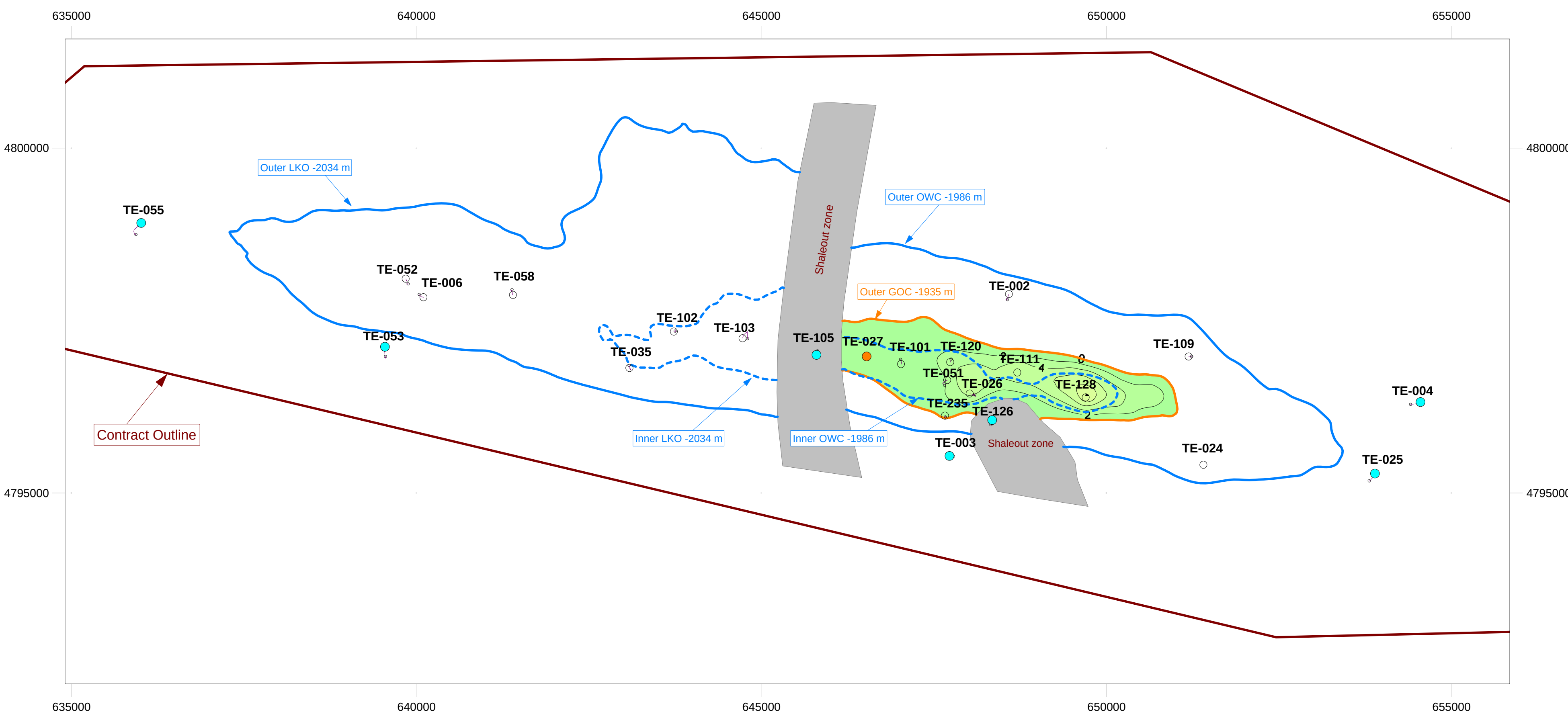


2 0 2 4 km

McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Oil Thickness Map
21b-c Sand

<mba>	Units – meters	4 May, 2011



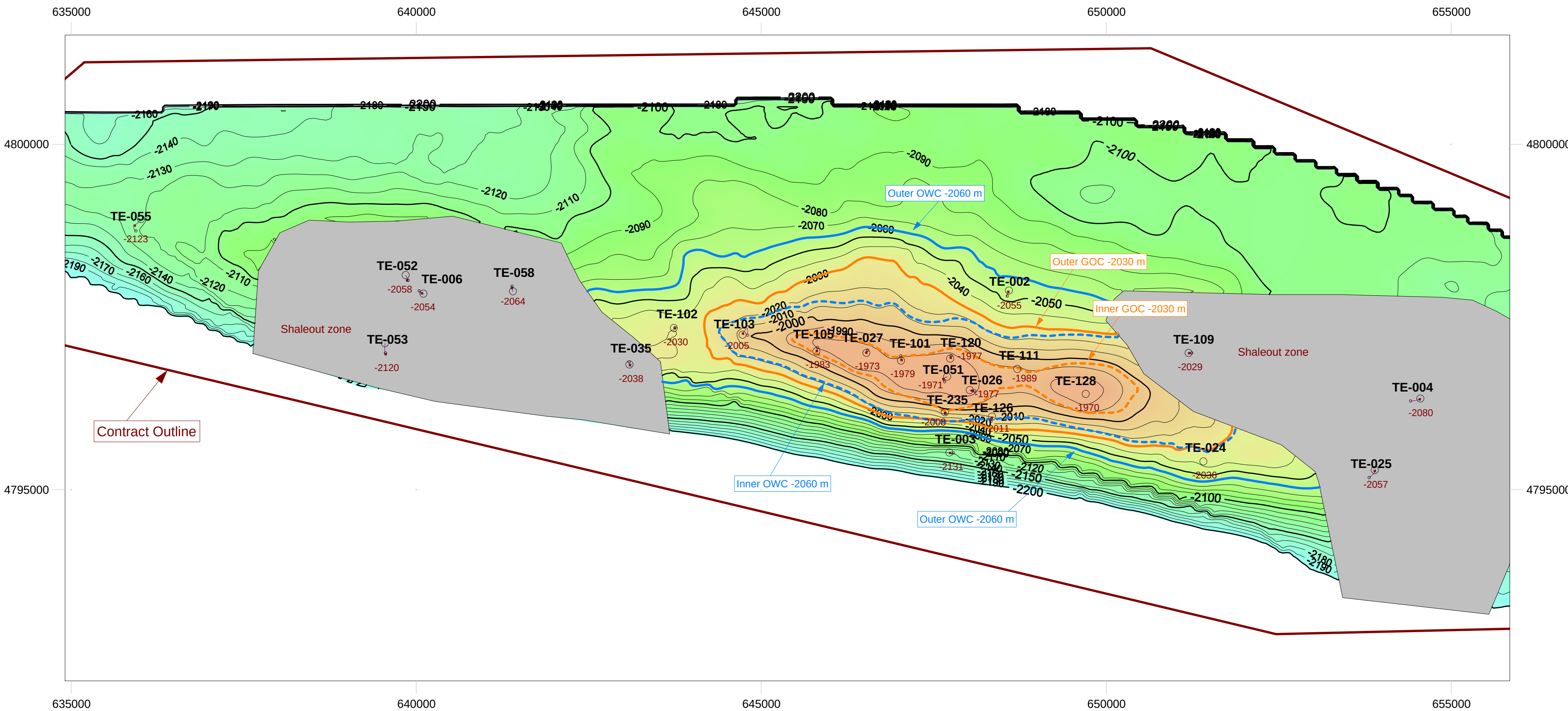
Well Legend	Map Abbreviations
Oil producer Oil tested Gas tested Oil and gas No hydrocarbons	OWC - Oil Water Contact GOC - Gas Oil Contact LKO - Lowest Known Oil

McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Gas Thickness Map
21b-c Sand

<mba>	Units – meters	4 May, 2011

Figure 15



Legend

OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
O - Drilled well

N
W
E
S

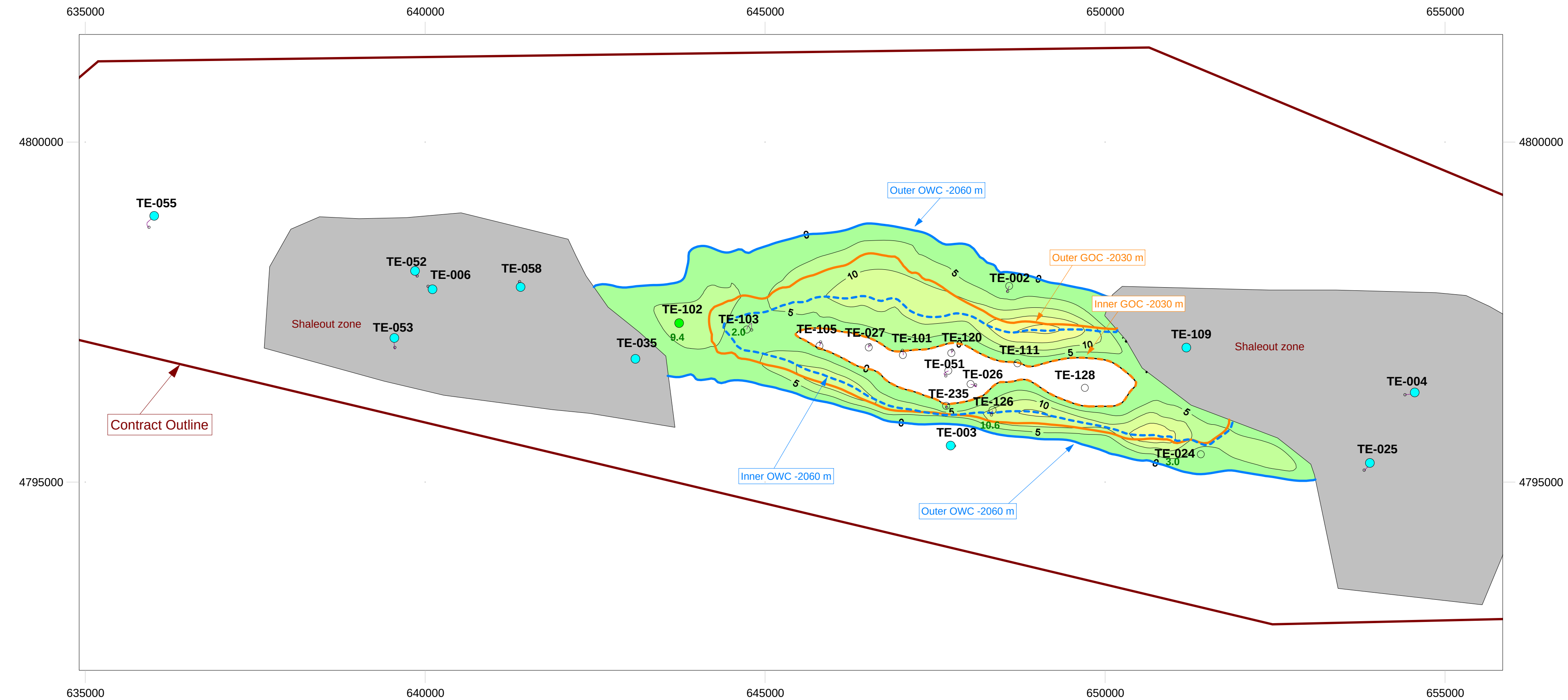
2 0 2 4 km

McDaniel
& Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
22a Sand

<mba>	Units – meters	4 May, 2011

Figure 16



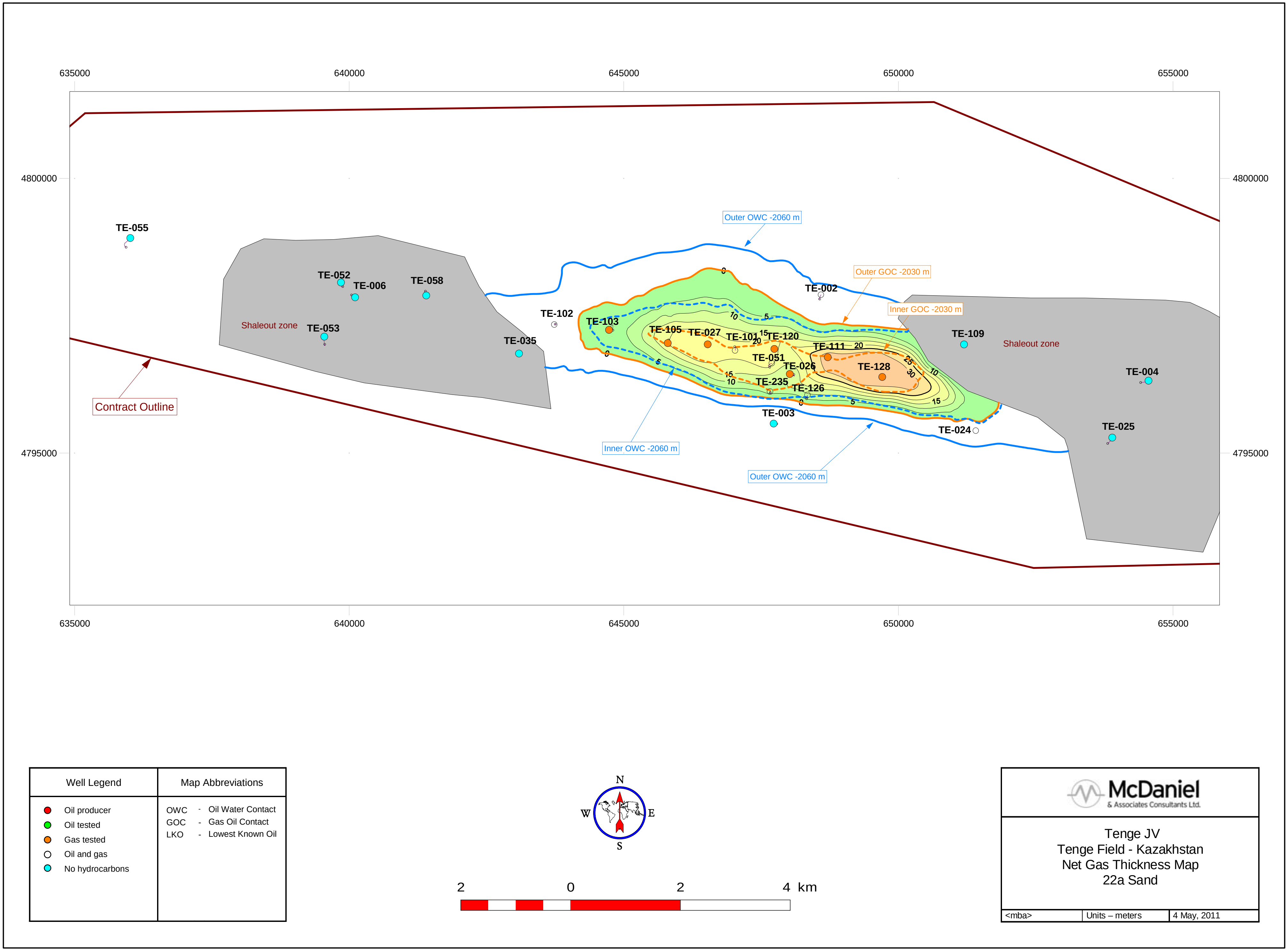
Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil tested	GOC - Gas Oil Contact
Gas tested	LKO - Lowest Known Oil
Oil and gas	
No hydrocarbons	

McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Oil Thickness Map
22a Sand

<mba>	Units – meters	4 May, 2011

Figure 17

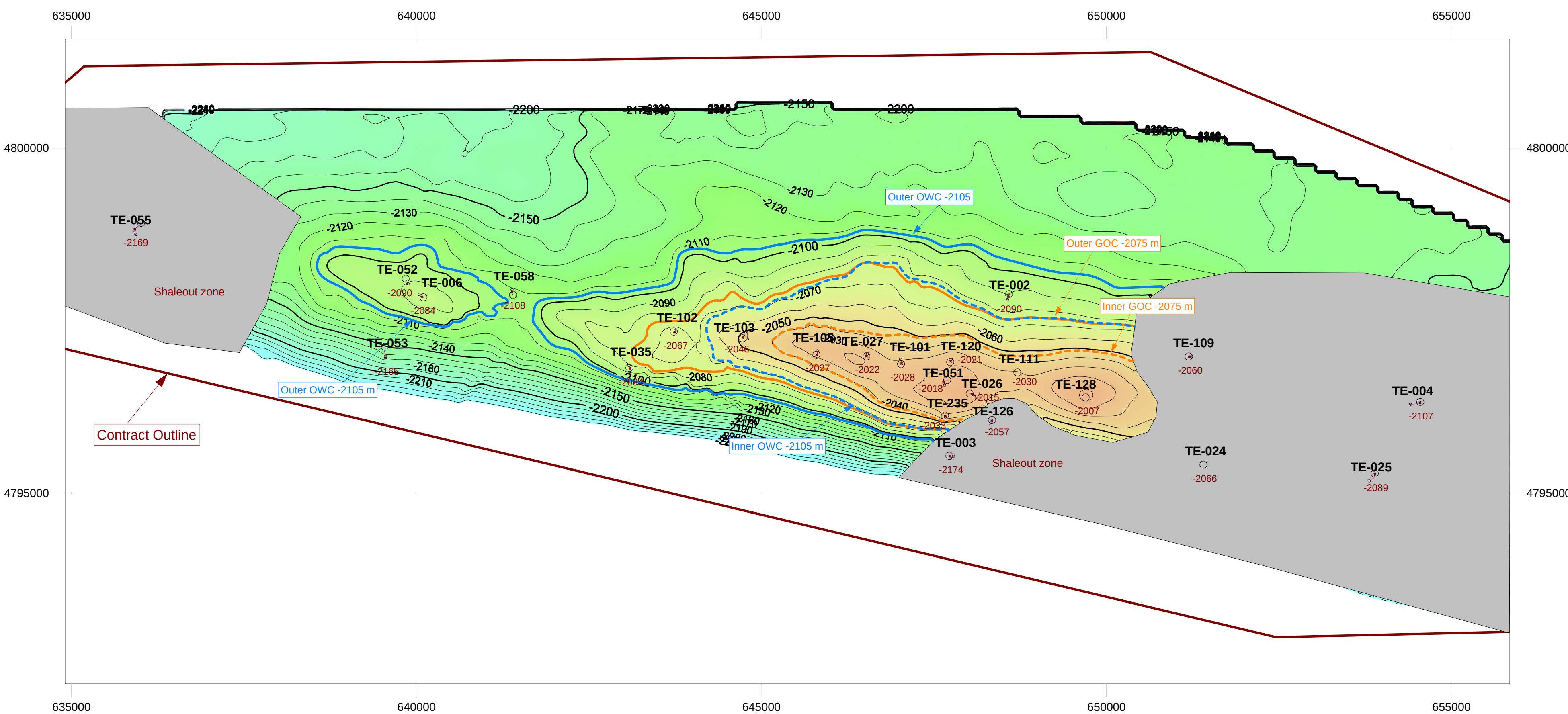


McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Gas Thickness Map
22a Sand

<mba>	Units – meters	4 May, 2011

Figure 18



Legend

OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
O - Drilled well

N
W E
S

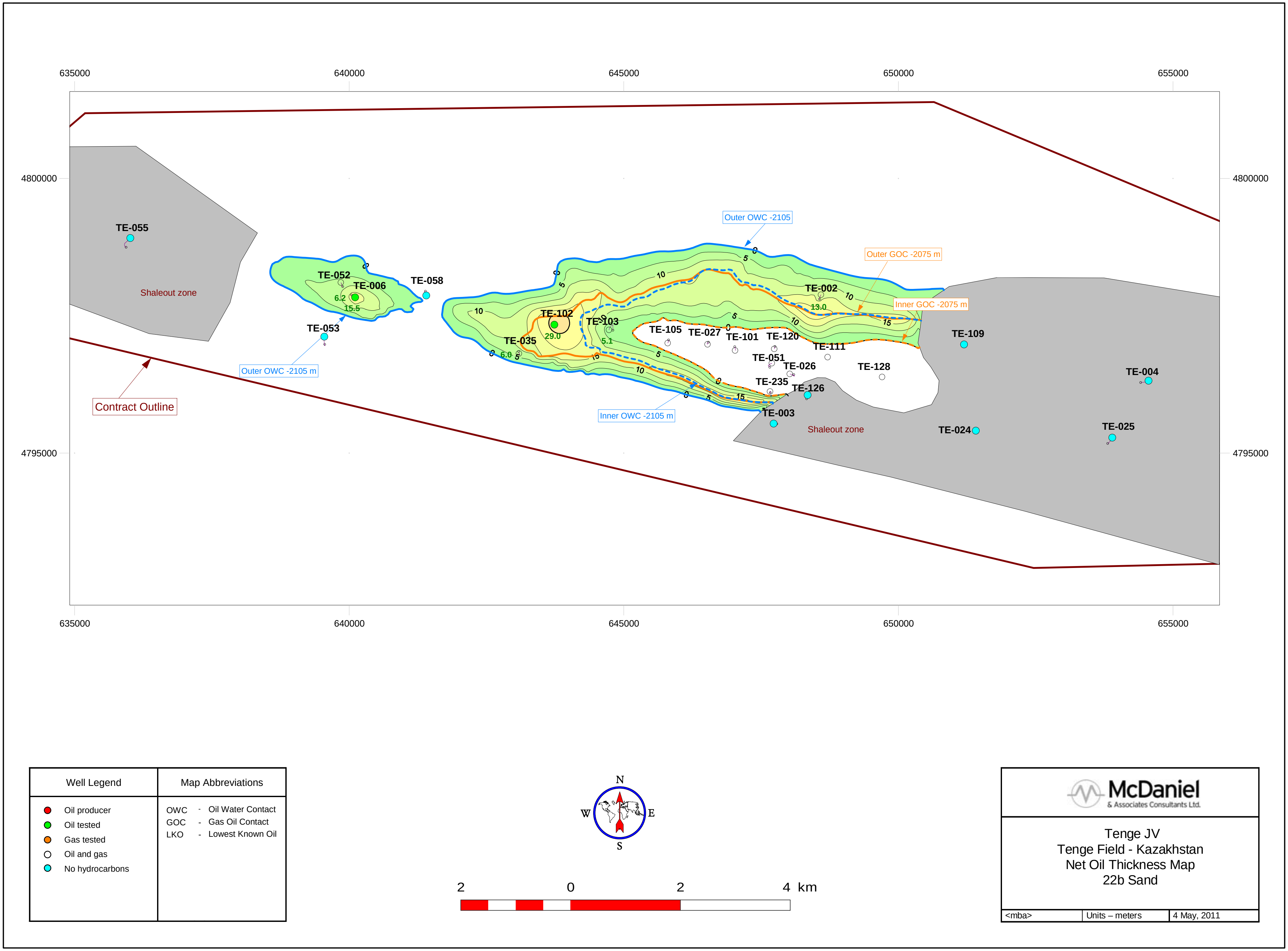
2 0 2 4 km

McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
22b Sand

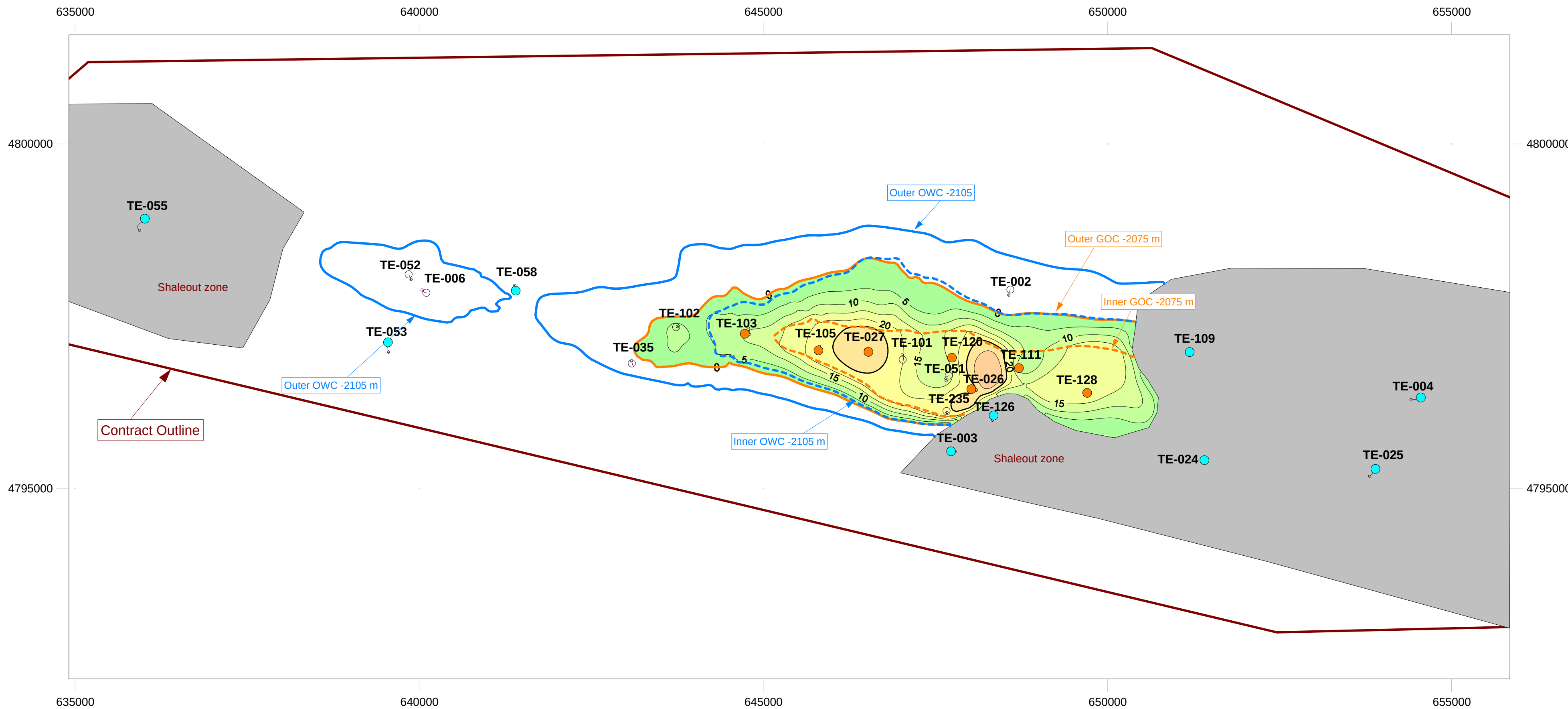
<mba>	Units – meters	4 May, 2011

Figure 19

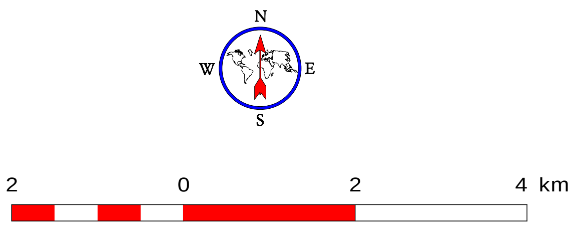


635000
640000
645000
650000
655000
4800000
4795000
TE-055
Shaleout zone
TE-052
TE-006
6.2
15.5
TE-058
TE-053
Outer OWC -2105 m
Contract Outline
TE-102
29.0
TE-103
5.1
TE-035
6.0
Outer OWC -2105
Outer GOC -2075 m
Inner GOC -2075 m
TE-002
13.0
TE-105
TE-027
TE-101
TE-120
TE-111
TE-051
TE-026
TE-128
TE-235
TE-126
TE-003
Inner OWC -2105 m
TE-109
TE-004
TE-024
TE-025
Shaleout zone
Well Legend
Oil producer
Oil tested
Gas tested
Oil and gas
No hydrocarbons
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
N
W
E
S
2 0 2 4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Net Oil Thickness Map
22b Sand
<mba>
Units – meters
4 May, 2011

Figure 20



Well Legend	Map Abbreviations
Oil producer Oil tested Gas tested Oil and gas No hydrocarbons	OWC - Oil Water Contact GOC - Gas Oil Contact LKO - Lowest Known Oil

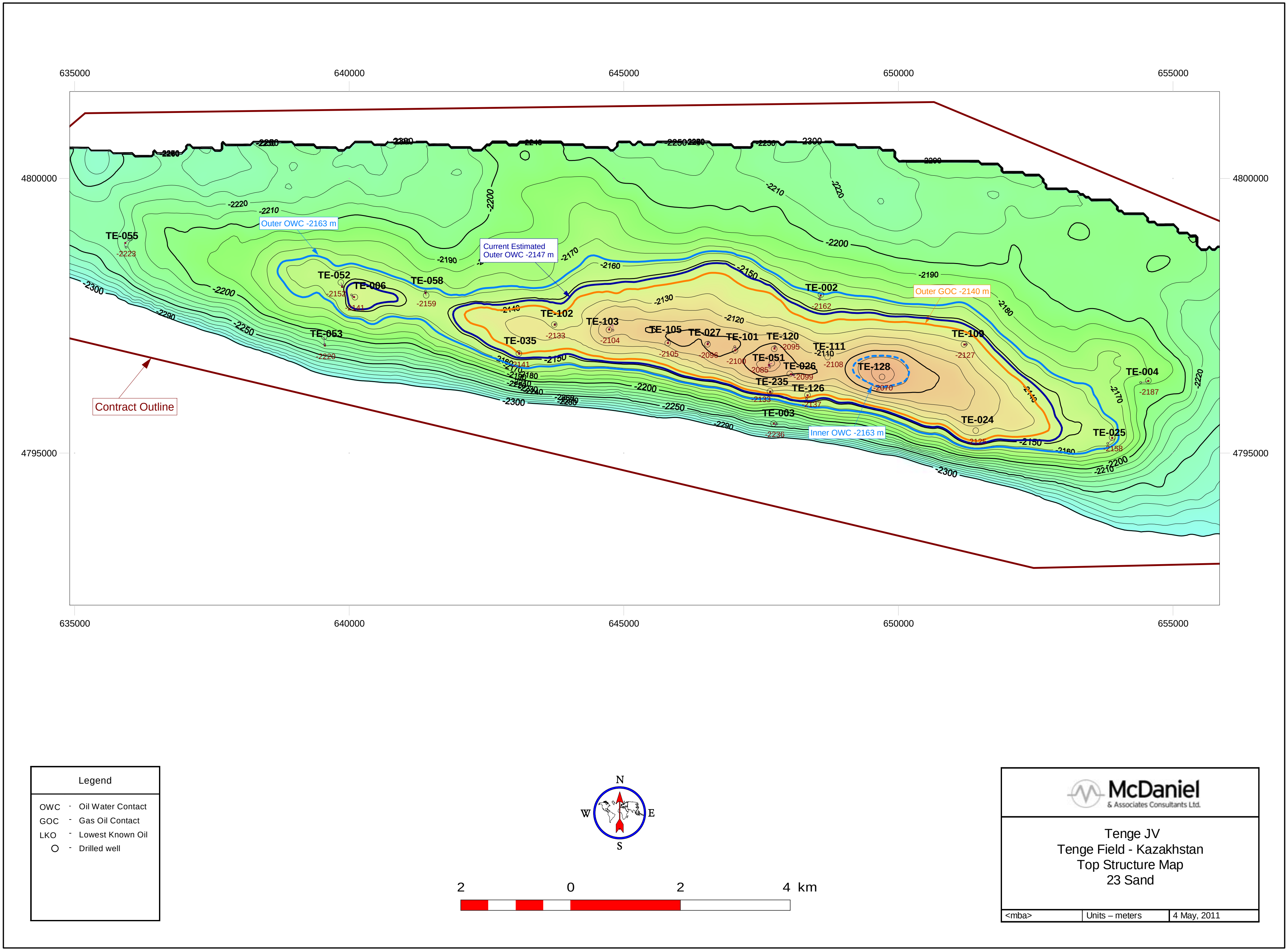


McDaniel & Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Net Gas Thickness Map
22b Sand

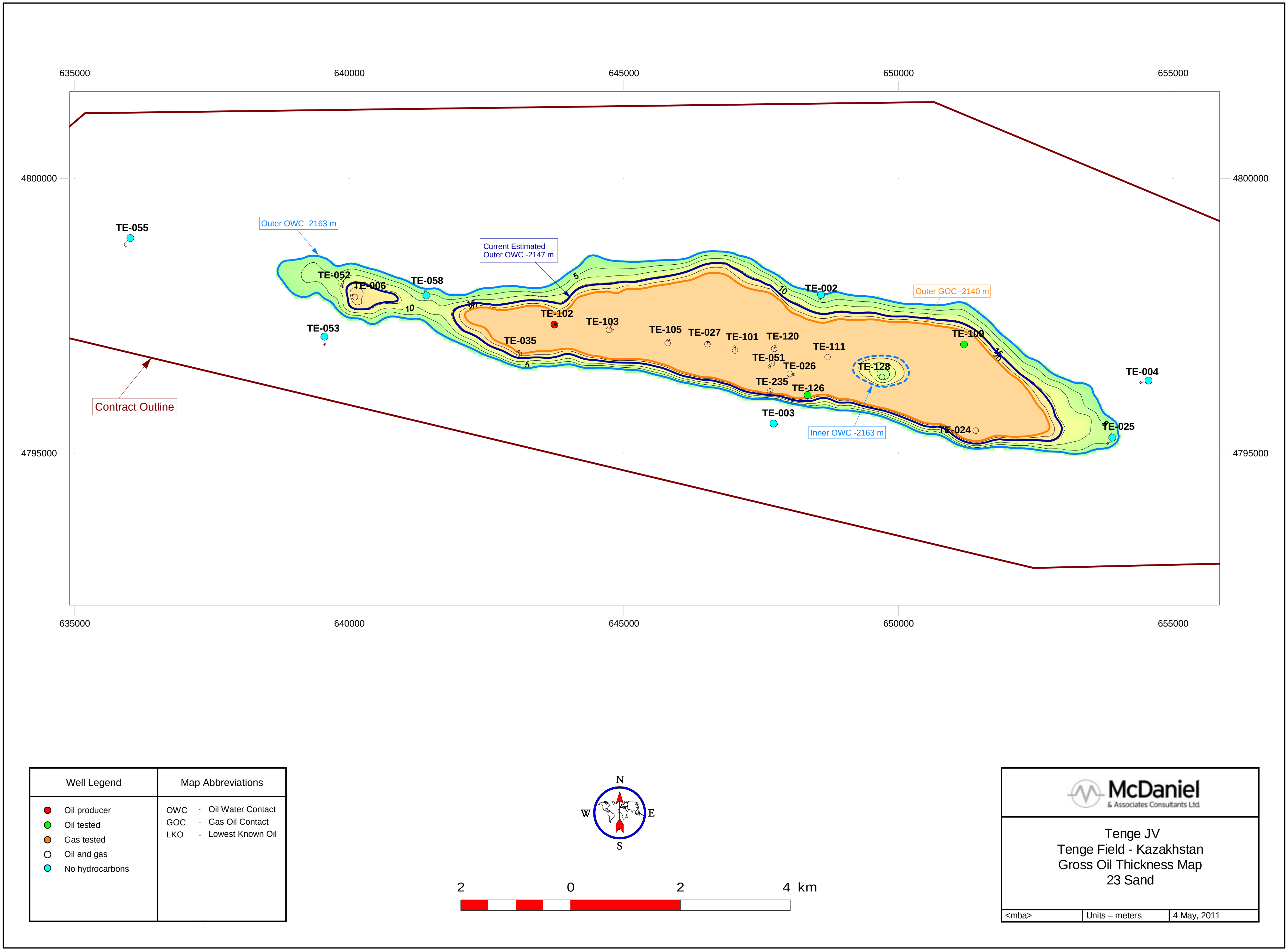
<mba>	Units – meters	4 May, 2011

Figure 21



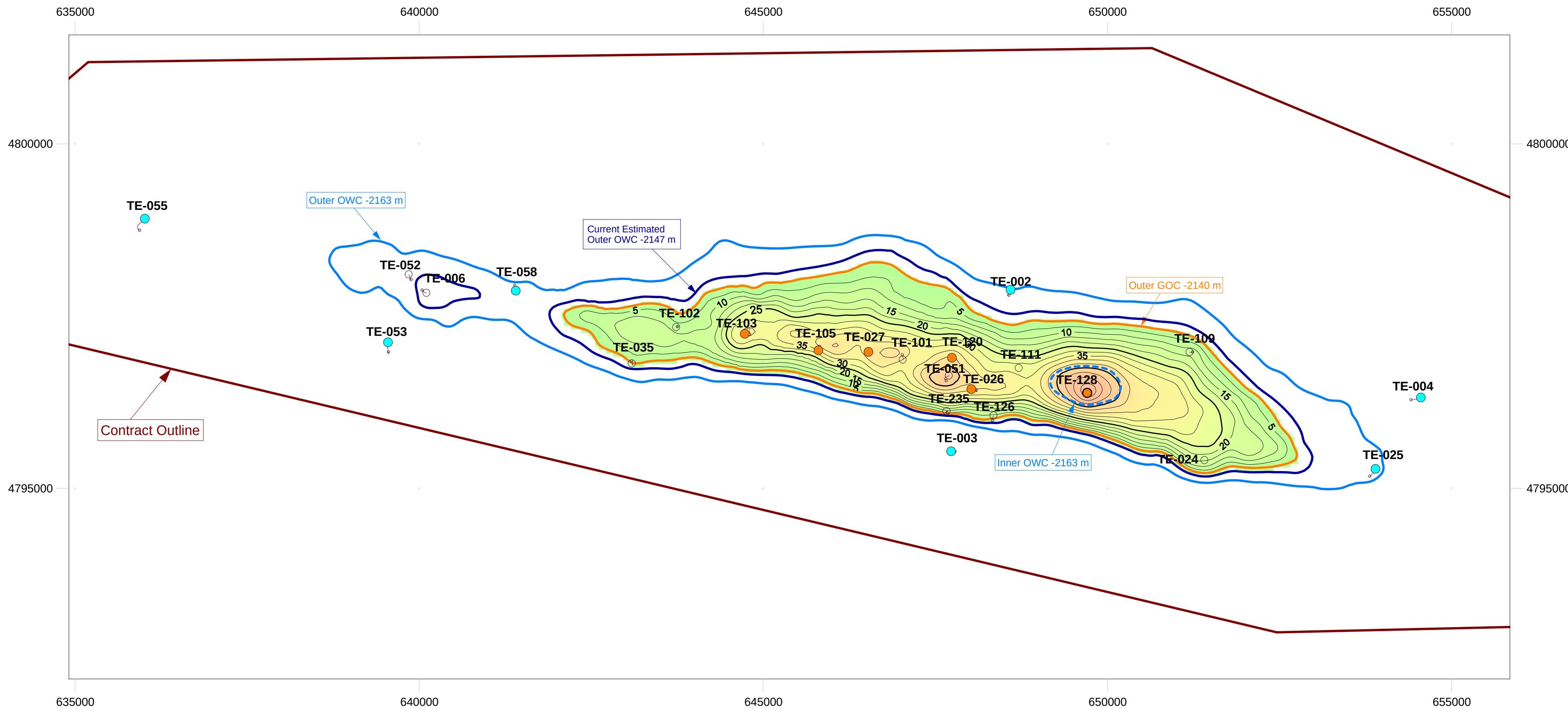
635000
640000
645000
650000
655000
4800000
4795000
TE-055
-2223
TE-052
TE-006
TE-058
-2159
TE-053
-2220
TE-102
-2133
TE-103
-2104
TE-035
TE-105
-2105
TE-027
TE-101
TE-120
-2095
TE-111
-2108
TE-051
TE-026
-2099
TE-235
-2133
TE-126
-2137
TE-003
-2236
TE-128
-2070
TE-002
-2162
TE-109
-2127
TE-024
TE-004
-2187
TE-025
-2158
Outer OWC -2163 m
Current Estimated
Outer OWC -2147 m
Outer GOC -2140 m
Inner OWC -2163 m
Contract Outline
-2300
-2200
-2220
-2210
-2190
-2170
-2160
-2150
-2140
-2130
-2120
-2250
-2290
Legend
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
Drilled well
N
W
E
S
2
0
2
4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Top Structure Map
23 Sand
<mba>
Units – meters
4 May, 2011

Figure 22

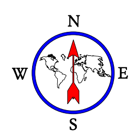


635000
640000
645000
650000
655000
4800000
4795000
TE-055
Outer OWC -2163 m
Current Estimated
Outer OWC -2147 m
TE-052
TE-006
TE-058
TE-053
TE-102
TE-103
TE-035
TE-105
TE-027
TE-101
TE-120
TE-002
Outer GOC -2140 m
TE-109
TE-111
TE-051
TE-026
TE-128
TE-235
TE-126
TE-003
Inner OWC -2163 m
TE-024
TE-004
TE-025
5
10
15
Contract Outline
Well Legend
Oil producer
Oil tested
Gas tested
Oil and gas
No hydrocarbons
Map Abbreviations
OWC - Oil Water Contact
GOC - Gas Oil Contact
LKO - Lowest Known Oil
N
S
E
W
2
0
2
4 km
McDaniel
& Associates Consultants Ltd.
Tenge JV
Tenge Field - Kazakhstan
Gross Oil Thickness Map
23 Sand
<mba>
Units – meters
4 May, 2011

Figure 23



Well Legend	Map Abbreviations
Oil producer	OWC - Oil Water Contact
Oil tested	GOC - Gas Oil Contact
Gas tested	LKO - Lowest Known Oil
Oil and gas	
No hydrocarbons	

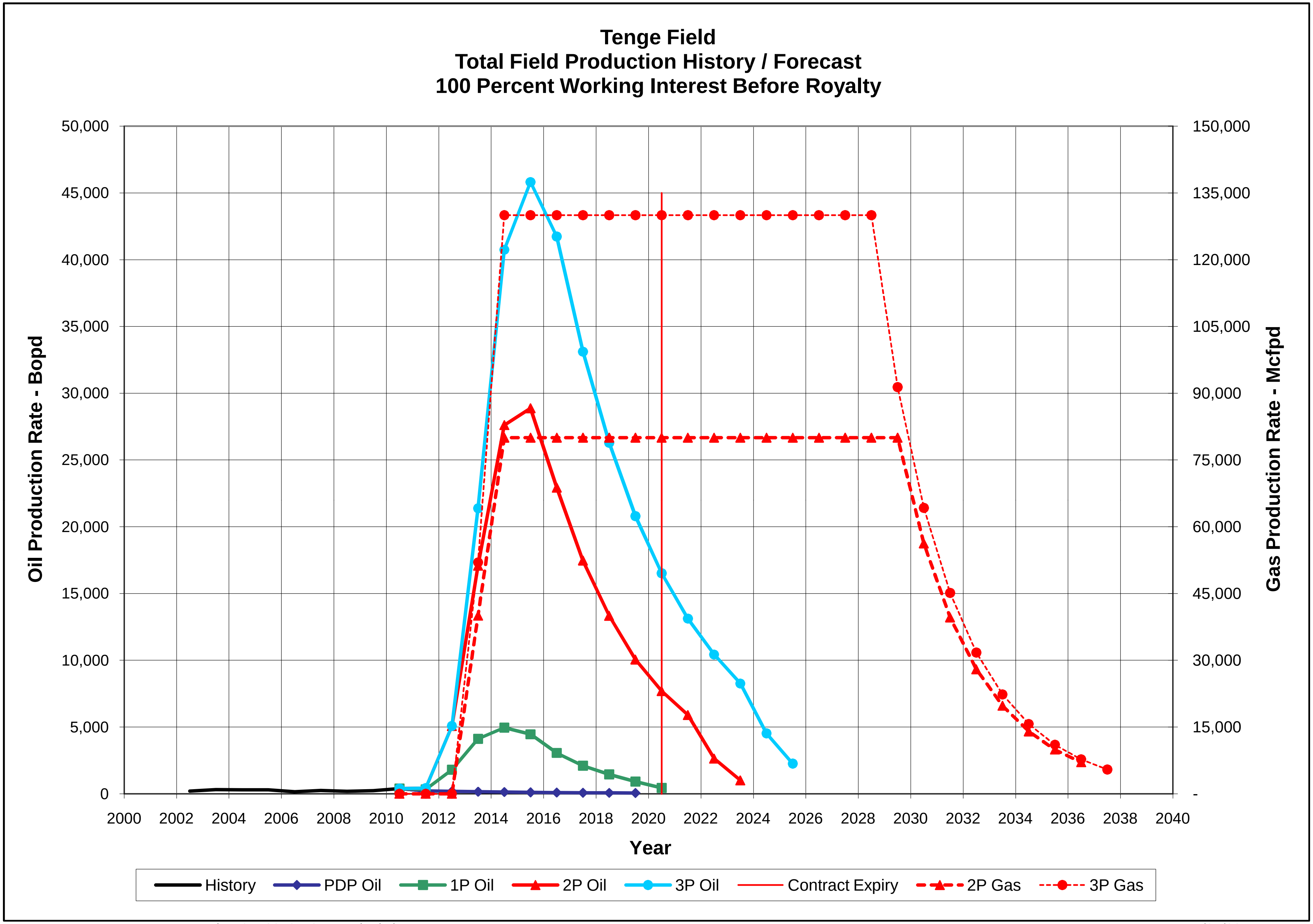


McDaniel
& Associates Consultants Ltd.

Tenge JV
Tenge Field - Kazakhstan
Gross Gas Thickness Map
23 Sand

<mba>	Units – meters	4 May, 2011

Figure 24



Tenge Field
Total Field Production History / Forecast
100 Percent Working Interest Before Royalty
Oil Production Rate - Bopd
Gas Production Rate - Mcfpd
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
150,000
135,000
120,000
105,000
90,000
75,000
60,000
45,000
30,000
15,000
-
2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020 2022 2024 2026 2028 2030 2032 2034 2036 2038 2040
Year
History
PDP Oil
1P Oil
2P Oil
3P Oil
Contract Expiry
2P Gas
3P Gas