The Directors
DWM
Bahnhofstr.9
CH-6341
Baar
Switzerland

21st September 2006

Dear Sirs,

<u>Update of July 2005 Independent Evaluation of certain Kyrgyzstan assets of DWM AG</u>

In July 2005, Scott Pickford delivered an Independent Evaluation on certain assets within Kyrgyzstan for DWM AG ("DWM" or "Company"). In that report we reviewed and gave indicative success case volumes and values for the DWM interests in these assets. The assets are held via a 90% holding in South Petroleum Company which is incorporated in the Republic of Kyrgyzstan.

In mid-September, DWM approached Scott Pickford (now part of RPS Energy) to release an updated report to take account of the uplift in both oil price forecasting and associated costs in the success case valuation. Since the July 2005 report was released, the Company has secured the renewal of the five blocks that were evaluated by Scott Pickford and acquired a new block, Arkyt. The Company has stated that no new exploration work has been carried out (see Company letter in Appendix D) and no data have been provided to RPS Scott Pickford for evaluation of the Arkyt block. Consequently, this update contains the same assumptions and scenarios as the July 2005 report with the exception of the oil pricing and associated costs.

In our statements and calculations the Licence interests quoted are those presented to us by DWM. Proof of title to these interests has been showed to us and further details are included in the executive summary. This report has been undertaken based upon data supplied to us by DWM. These data consisted of paper copies of scanned seismic lines, geological and petrophysical analyses and reports available all in paper format. These data were made available at a series of presentations given by Dr. Alexander Becker of DWM with subsequent email communications.

The guidelines laid out in the 2001 SPE/WPC/AAPG publication have been adopted for our definition of Reserves and Resources. The potential hydrocarbons within the DWM assets belong clearly in the Prospective Resource category. Our calculations of recoverable hydrocarbon volumes have been performed in a probabilistic manner with the Low, Best and High estimates equating to the corresponding P90, P50 and P10 confidence levels. Brief definitions of these terms are to be found in Appendix A.

For the various assets we have evaluated conceptual development scenarios that reflect the availability of a market for the oil. Indicative Net Present Values (NPVs) have been calculated for selected potential accumulations within the assets and these have values have then been risk adjusted to produce Expected Monetary Values (EMVs). Scott Pickford has made its own assessment with regards to the technical risk attached to these assets.

This report relates specifically and solely to the subject assets and is conditional upon various assumptions. This report must, therefore be read in its entirety. This report may be used in its entirety without prior permission from Scott Pickford. However should excerpts from this report be used by DWM (or its affiliates) then express permission must be obtained from Scott Pickford. Any such excerpts should specifically draw the reader's attention to the need to read the entire report. It is an express condition of permission of such use that DWM (or its affiliates) shall grant access to the report if such notice is acted upon. This procedure is to ensure that all use of information and views expressed in the report are represented in a true and fair manner. A glossary of all the technical abbreviations used in this report is included as Appendix A.

Yours faithfully,

Andy Kirchin

Managing Director
Scott Pickford Ltd
(Part of RPS Energy)

A Valuation of the Kyrgyzstan Assets

of

DWM AG

This report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. This report must, therefore, be read in its entirety.

This report was provided for the sole use of DWM AG on a fee basis. Except with permission from Scott Pickford Limited, this report may not be reproduced or redistributed, in whole or in part, to any other person or published, in whole or in part, for any purpose without the express written consent of Scott Pickford Limited.

Our estimates of potential reserves, resources, unrisked and risked values are based on data provided by DWM. We have accepted, without independent verification, the accuracy and completeness of these data.

All interpretations and conclusions presented herein are opinions based on inferences from geological, geophysical, engineering or other data. The report represents Scott Pickford Limited's best professional judgement and should not be considered a guarantee of results. Our liability is limited solely to DWM , its brokers and advisors

September 2006

List of Contents

List of Figures

List of Tables

1. Executive Summary

In July 2005, Scott Pickford delivered an Independent Evaluation on certain assets within Kyrgyzstan for DWM AG ("DWM" or "Company"). In that report we reviewed and gave indicative success case volumes and values for the DWM interests in these assets. The assets are held via a 90% holding in South Petroleum Company which is incorporated in the Republic of Kyrgyzstan.

In mid-September, DWM approached Scott Pickford (now part of RPS Energy) to release an updated report to take account of the uplift in both oil price forecasting and associated costs in the success case valuation. Since the July 2005 report was released, the Company has secured the renewal of the five blocks that were evaluated by Scott Pickford and acquired a new block, Arkyt. The Company has stated that no new exploration work has been carried out (see Company letter in Appendix D) and no data have been provided to RPS Scott Pickford for evaluation of the Arkyt block. Consequently, this update contains the same assumptions and scenarios as the July 2005 report with the exception of the oil pricing and associated costs.

Originally, DWM had a 90% effective interest in five exclusive exploration Licences in the Fergana Basin, Kyrgyzstan held by South Petroleum Company Limited (SPC). Table 1 gives details of these Licences as of July 2005 and Figure 1 shows their location. Table 1a shows the new details of the Licences following DWM's negotiations to renew the licences in 2006. These exploration Licences are located adjacent to established oil and gas producing areas although the currently producing areas are specifically excluded from the exploration licences. The licences were valid initially for a period of two years from the date of award but could be extended for ten years provided that the Company was in compliance with the terms of the relevant licence agreement. During 2006, despite no further exploration activity the Company has been granted an extension to end 2008 for Nanai and Naushkent and four year extensions for Soh, west Soh and Tuzluk. When a commercial discovery is made SPC will be granted exclusive rights to an exploitation licence, initially valid for a period of no longer than 20 years, with subsequent extensions dependent on the degree of depletion.

Licence	Entitlement interest (%)	Area (km^2)	Date of Award
Nanai	90	1272	July 9th 2004
Soh	90	631	November 30th 2004
West Soh	90	160	April 29th 2004
Tuzluk	90	474	April 29th 2004
Naushkent	90	41	April 29th 2004

Table 1 – Summary of DWM Licence Interests as of July 2005

Licence	Entitlement (%)	Area (km^2)	Original Expiry	Renewal Date	New Expiry
Nanai	90	999	09.07.2006	14.06.2006	31.12.2008
Soh	90	631	09.07.2006	29.04.2006	29.04.2010
West Soh	90	160	29.04.2006	29.04.2006	29.04.2010
Tuzluk	90	474	29.04.2006	29.04.2006	29.04.2010
Naushkent	90	41	29.04.2006	14.06.2006	31.12.2008
Arkyt	90	848	n/a	23.08.2005	23.08.2007

Table 1a – Summary of DWM Licence Interests as of September 2006

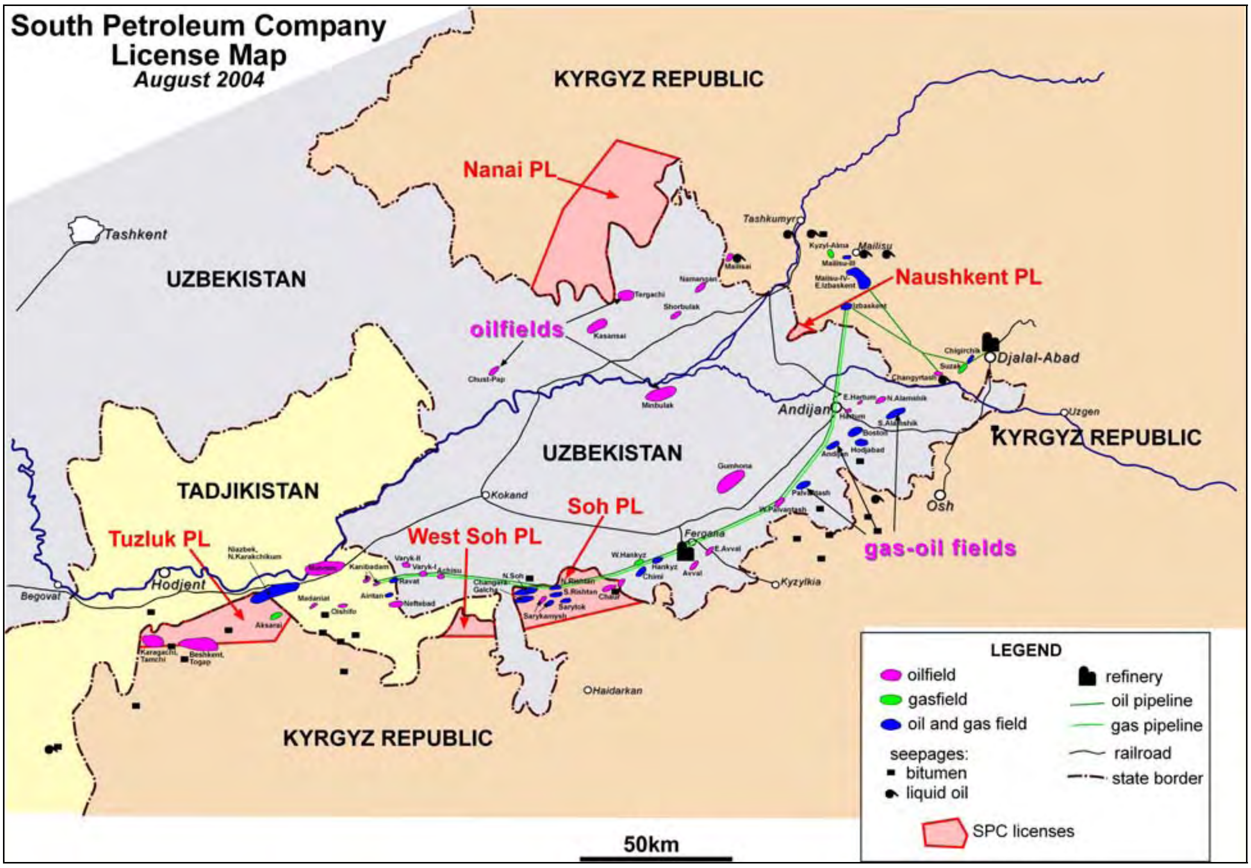


Figure 1 – Location Map of the DWM (Southern Petroleum Company) Licences

The DWM Licences lie in the Fergana Basin which is an intermontane basin the greater part of which lies mainly in the eastern part of Uzbekistan (see Figure 1). There is a long history of petroleum production from this basin stretching back to the start of the last century and a large number of fields have been developed. The currently producing fields are operated by KNG (Kyrgz NefteGaz) and are all well off plateau and as a result there is ample ullage available in the pipelines connecting them to the production facilities. Production is of both oil and gas with the gas occurring sometimes as free gas and at others as associated gas (i.e produced along with the oil). The presence of gas and/or gas-condensate reservoirs located below oil charged reservoirs indicates a complex fill history and the wide variations in fluid properties will contribute to some uncertainty with regards to the exact nature of the hydrocarbons expected within each prospect. The Nanai and Naushkent prospecting licences were both recently acquired and lie in the northern border zone of the basin adjacent to the national border with Uzbekistan. Both licences, although relatively close to existing production (in Uzbekistan), are poorly explored with little drilling or seismic activity. The Soh, West Soh and Tuzluk prospecting licences lie in the more mature southern border zone adjacent to the national borders with Uzbekistan and Tajikistan respectively. These Licences contain a large amount of existing production with the exception of the small West Soh Licence that is relatively unexplored.

Stage	Formation	Index	Paybed	Column	Thickness m	Lithology	Porosity, % min-max	Netpay, m min-max	Production in neighbouring fields
Pliocene	Baktry	N_2bk			2100-3500	Gray conglomerate, gritstone and sandstone with lenses of sandy clay with lenses of sandy clay			
			bk		18	Sandstone, gravelite, conglomerate	15	12	non-comercial oil in well Alabuka-1
					400	Gray conglomerate, gritstone and sandstone with lenses of sandy clay with lenses of sandy clay			
Miocene	Massaget	P_3-N_1ms			1400-2000	Pink clay, sandstone, gritstone with beds and lenses of conglomerate			
Oligocene			kkp		25-40	Sandstone, conglomerate, gritstone	11-22	6-38	oil from various stratigraphic levels of P_3-N_1ms
Eocene	Sumsar	P_2sm			15	Dark red clay and siltstone			
			III		14	Red to light red sandstone, gritstone	20	13	oil - Minbulak
					20	Dark red clay			
	Hanabad	P_2hb			15	Green clay			
	Isfara	$P_2$is			15	Brown and light green clay, siltstone, flintclay			
	Rishtan	P_2rš			8	Green sandy clay			
			IV		20	Green sandstone with interbeds of gritstone at the bottom			
	Turkestan	P_2tr			14	Light green clay			
			Va		7	White limestone, calcarenite, detrital limestone			
					4	Green sandy clay			
			Vb		11	White limestone, calcarenite	11	3.1	oil
					10	Light green and gray siltstone,marl, sandstone, clay			
	Alay	P_2al	VIIa		12	Coquina, detrital limestone	11	2.4	oil
					7	Green sandy clay			
			VIIb		14	White limestone, calcarenite, sandy limestone	15	12	oil - Minbulak
	Suzak	P_2sz			27	Greenish-gray sandstone, siltstone and clay			
			IX		20	White limestone, calcarenite	15	12	gas and condensate Minbulak
					10	Green, red and brown clay, sandstone			
Paleocene	Buhara	P_1bh			20	Red clay, sandstone, siltstone with beds of sandstone			
Cretaceous	Cretaceous	K			220	Red, white conglomerate, clay, with lenses of gritstone and limestone			
						Basalt, limestone			

Figure 2 – A Representative Stratigraphic Column for the Ferghana Basin

The structural interpretation of this area from the soviet era is typified by the cross section through the Beshkent Field close to the Tuzluk Licence shown in Figure 3.

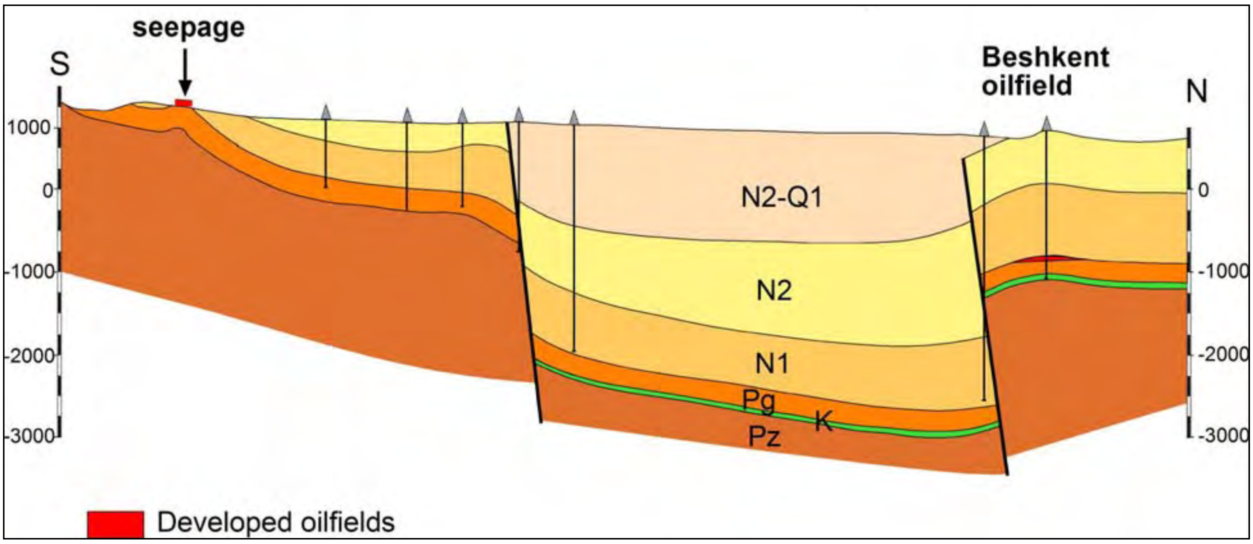


Figure 3 – Old Soviet style interpretation of the Beshkent Oilfield

These old interpretations were characterised by vertical (or near vertical) faults. More recently these areas have been re-interpreted incorporating low angle thrust faulting giving rise to the radically different interpretation shown in Figure 4 below.

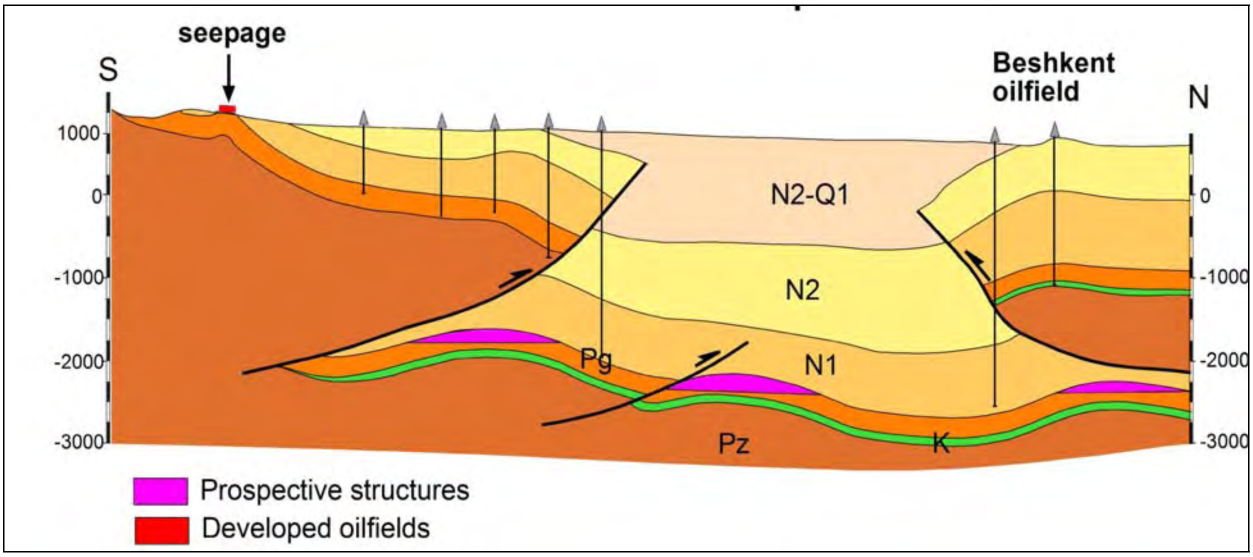


Figure 4 – Modern interpretation of the Beshkent Oilfield incorporating low angle thrusts

This more modern interpretation leads to the possibility that there are a large number of deeper structures that were not previously recognised and hence remain untested. DWM's strategy is to concentrate, for the most part, on these deep, untested, sub-thrust structures. However, these deeper structures are not properly imaged by the existing seismic data and as a result the eight structures that DWM has identified for review within the Licences (excluding Naushkent) are based on a variable amount of data both in terms of quality and quantity. This data has been gathered from many different sources and collated as well as is possible to highlight those areas of interest. Where available, old Uzbek and Tajik maps, together with restricted seismic and well data, have been used to establish the presence of structures by analogy. All of the seismic data viewed and utilized in this report consists of scanned copies of old Soviet paper data, much of it of very poor quality. The only strong regional seismic markers are the Eocene-Palaeocene limestone beds V, VII, IX and the Upper Cretaceous limestones. The depth conversion method used in all cases, with the exception of the Nanai PL (see below) is very basic. The depth to the mapped horizons has been calculated by using a single contoured average velocity map derived from wells, few of which have reached the deeper targets, and is therefore prone to significant error. A considerable amount of geological and fluid property data is available on the existing fields that are producing from the same reservoir units that are expected in the prospects. This data has been used by Scott Pickford in its attempts to estimate the range of potential volumes of hydrocarbons that these structures could contain. These estimates are based, in some cases, on little or no Kyrgyz seismic data and limited amounts of local well information. This lack of data has naturally had an effect on the chance of success (CoS) that Scott Pickford has attributed to these leads with the general trend being to increase the risk. However, once new seismic data has been acquired, interpreted and carefully depth converted it is expected that the structures that result from this work will have substantially lower the risks attached to them. This reduction in risk is likely because as the presence of source and reservoir is almost ubiquitous in the region, structural definition remains the key to prospectivity.

.

Licence	Prospect	STOIIP (MMbbls)		
		Min	Most Likely	Max
Nanai	Alabuka -1	73.7	107.4	140.4
	Alabuka -2	39.0	73.9	169.7
	Alabuka -3	51.2	65.7	89.9
Soh	Burdalyk	227.5	398.4	611.4
	Kyzyl-Kurgan	89.6	149.7	220.0
	West Chaur	122.9	125.4	128.7
Tuzluk	South Tuzluk	67	129	189
	West Tuzluk	25.6	49.6	73.5
	East Tashravat	65.3	91.8	126.5
	West Beshkent	22.3	31.5	44.3
Totals		784.1	1222.4	1793.4

Table 2 - Summary of the STOIIPs for the currently identified Prospects in the DWM Licences

Licence	Prospect	GIIP (Bcf)		
		Min	Most Likely	Max
Nanai	Alabuka -1	136.7	198.9	260.1
	Alabuka -2	72.3	137.0	314.4
	Alabuka -3	94.9	121.7	166.6
Soh	Burdalyk	24.0	42.1	64.6
	Kyzyl-Kurgan	9.2	15.4	22.6
	West Chaur	41.4	42.2	43.3
Tuzluk	South Tuzluk	14.7	22.4	31.8
	West Tuzluk	7.6	14.8	21.9
	East Tashravat	14.7	20.6	28.4
	West Beshkent	5.0	7.1	10.0
Totals		420.5	622.2	963.7

Table 3 - Summary of the GIIPs for the currently identified Prospects in the DWM Licences

Relatively little detailed information is however available on the production rates achieved in the existing fields and as a result Scott Pickford has made a number of assumptions with regards to the likely productivity index of individual wells and their predicted rate of decline. These assumptions will require verification from actual field data once the initial exploration wells have been drilled. Two basic development scenarios have been considered namely, production under natural depletion and production utilising water injection to provide pressure support. It has been assumed following discussions with DWM that the first drilling campaign will consist of 5 wells. The targets for these wells have been chosen on the basis of a combination of economic attractiveness, play type and geographical location. The following table gives details of the Prospective Resources (risked and unrisked) and the economic value (NPV and EMV) for the primary prospects (i.e. those thought likely to be the targets in the first drilling campaign) in the DWM licences. The values quoted are for the water injection development scenario with initial well productivities assumed to be 300bbls/d for shallow prospects and 1000bbls/d for the deeper prospects. These values are considerably higher than those for the comparable natural depletion development scenarios which are presented in section 4 of this report for comparison. Scott Pickford believes the assumptions made with regards to the likely benefits of utilising water injection to provide pressure support are reasonable. These assumptions are described in section 3 of this report which covers reservoir engineering. Therefore given the predicted value increase modelled to accrue from the use of water injection this development scenario has been considered as the most likely case. The economic values quoted in this report are calculated with the assumption that the oil will be sold domestically to the refinery in Kyrgyzstan. Should the amount of oil discovered exceed the capacity of this refinery there remains the options to either upgrade the refinery (the preferred option) or to export the oil. If the export option is selected then additional transport charges will accrue although these will be partly offset by the removal of any excise duty obligations.

Licence	Prospect	Unrisked Prospective Resources Best Estimate (MMbbls)	CoS (%)	Risked Prospective Resources Best Estimate (MMbbls)	NPV_{10} (US$ MM)	EMV_{10} (US$ MM)
Nanai	Alabuka -1	30.76	20.5	6.31	239.02	44.71
Soh	Burdalyk	110.25	23.0	25.36	883.15	200.35
	West Chaur	34.69	50.0	17.35	347.21	172.71
Tuzluk	South Tuzluk	36.62	23.0	8.42	332.08	73.61
	East Tashravat	25.33	32.4	8.21	233.79	74.53
Totals		237.65		65.65	2035.25	565.91

Table 4a - Summary of the Prospective Resources (Best estimate) and the Risked and Unrisked values net to DWM for the Primary DWM Prospects assuming a 10% discount rate under a water injection scenario

In the case that the first drilling campaign is successful (either wholly or partly) DWM has already recognised a number of other prospects that could be readily firmed up for exploration drilling. To a certain extent these secondary prospects are dependent on the outcome of the initial wells therefore their potential Prospective Resources (risked and unrisked) and economic value (NPV and EMV) are presented in a separate table below.

Licence	Prospect	Unrisked Prospective Resources Best Estimate (MMbbls)	CoS (%)	Risked Prospective Resources Best Estimate (MMbbls)	NPV_{10} (US$ MM)	EMV_{10} (US$ MM)
Nanai	Alabuka -2	21.20	12.8	2.71	165.77	16.51
	Alabuka -3	19.27	10.2	1.97	170.22	14.13
Soh	Kyzyl-Kurgan	43.50	23.0	10.00	344.77	75.14
Tuzluk	West Tuzluk	13.49	14.4	1.94	114.93	13.47
	West Beshkent	8.65	50	4.32	83.84	41.02
Totals		106.11		20.94	879.53	160.27

Table 4b - Summary of the Prospective Resources (Best estimate) and the Risked and Unrisked values net to DWM for the Secondary DWM Prospects assuming a 10% discount rate under a water injection scenario

The above quoted values are based on an oil price of \$35/bbl. If a price of \$45/bbl is used then the EMV_{10} increases to \$787.09 million for the primary prospects and \$232 million for the secondary prospects. The gas resources have little commercial value and currently all the prospects have a negative EMV. The EMVs may become positive after the new seismic has been incorporated and the Chance of Success has hopefully increased. It may possible to develop the gas resources concurrently with the oil, with the gas being used to satisfy local demands. In those prospects where the gas occurs solely as associated gas it would be utilised to provide power for the development operations thus slightly reducing the field Opex. It may also possible to re-negotiate the gas price received and hence improve the value.

DWM recognise the need for much more extensive work in the licences, particularly the acquisition of new, state of the art, seismic data to better define the current structural model in this complex basin. A seismic programme has been proposed costing approximately $5million that will address the key currently recognised prospects. This programme will be the first task to be embarked upon once sufficient funds are available.

Although the DWM portfolio is dominated by sub-thrust prospects there are also a number of alternative prospects at shallower structural levels which add diversity to the play types available for exploitation. These shallower plays are also relatively low risk and economically attractive.

Should the initial drilling campaign prove successful then in addition to the secondary prospects already identified a potentially large number of further prospects could be revealed by the acquisition of further seismic data. Two possible prospects (Selkan and Arka in the Tuzluk licence area) have already been identified.

In conclusion the DWM licences contain a number of prospects and leads that require additional seismic data before they can be considered ready for drilling. The benefits of this seismic data will be to improve the definition of the prospects both in terms of the likely hydrocarbon volumes they may contain and the exact location of the prospect limits. DWM accordingly plan to acquire a seismic programme costing $5 million that will cover the top 5 currently high-graded prospects. This seismic will require detailed interpretation and time-to-depth conversion in order that the location of the exploration wells can be properly selected. It is expected that the Chance of Success will be considerably improved following the acquisition and interpretation of the seismic data and this will translate into a commensurate increase in EMV.

Assuming that hydrocarbons are discovered our modelling of possible development scenarios suggest that the shallow prospects only require initial well flowrates of 300bbls/d in order to be profitable. Rates of this magnitude have been proven from existing comparable production in the area. For the deeper prospects it is necessary to achieve flowrates in the order of 1,000bbls/d to achieve strong positive values. If a further assumption is made that an effective water injection programme can be implemented then these values can be increased further.

2. Description of the DWM Assets

The Ferghana basin is elongate in an east-northeast to west-southwest direction and extends into Kyrgyzstan and Tajikistan covering an area of approximately 40,000km^2. The basin formed during Jurassic to Neogene subsidence and was subjected to intense orogenic movement during the Alpine phase. The sedimentary cover consists mainly of Mesozoic and Cenozoic age rocks. A substantial report by the US Department of Energy has been compiled on the area and was available to Scott Pickford for this study. The productive reservoirs in the region are characterised by an extensive high amplitude seismic package that can be interpreted even on the old soviet era seismic data. The reservoirs consist primarily of clastics and carbonates of Eocene-Palaeocene age although on occasion Oligo-Miocene and Cretaceous reservoirs contribute to production. Figure 5 shows an excerpt from a central Tuzluk area well log with the main reservoir units labelled.

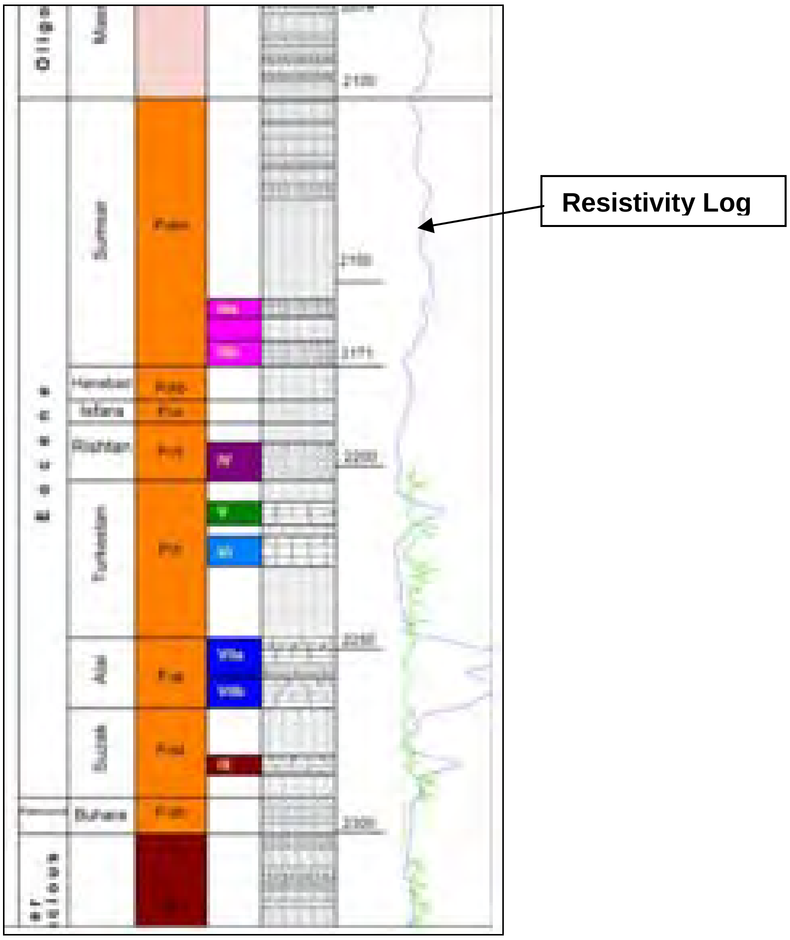


Figure 5 – Typical well log through the regional reservoir section

2.1. Nanai Prospecting Licence

The Nanai PL is located in the northern zone of the Fergana Basin adjacent to the border with Uzbekistan to the south (see Figure 1). Three structures called Alabuka 1, 2 and 3 have been identified by DWM and are shown in Figures 6 and 7. The seismic database consists of seven dip and four strike lines although only the ends of three of these lines cover any part of the structures. Therefore the structural definition relies heavily on the use of analogies to proven structures mapped in Uzbekistan to the south. The current mapping covers only approximately 10% of the available area and similar structures are thought to exist elsewhere within the licence. Therefore there is considerable upside potential in this Licence however this cannot be quantified with the current database.

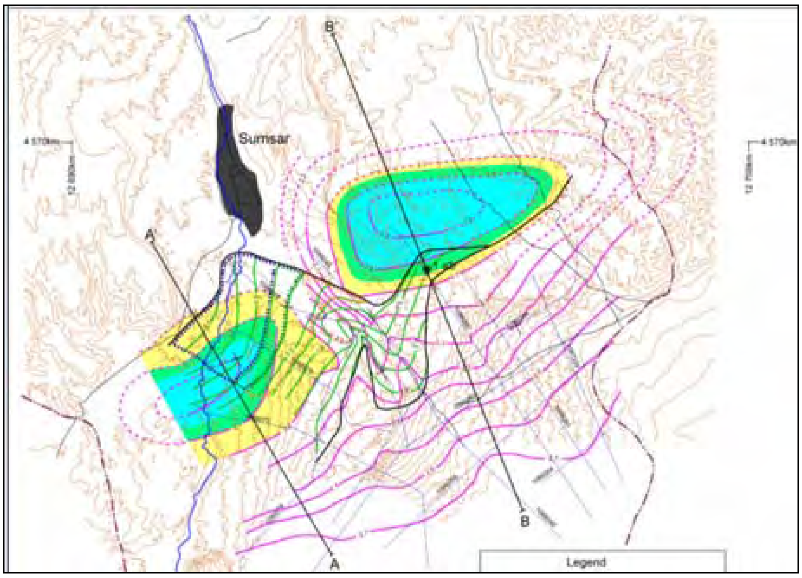


Figure 6 – Time Structure Map of the Alabuka Structures

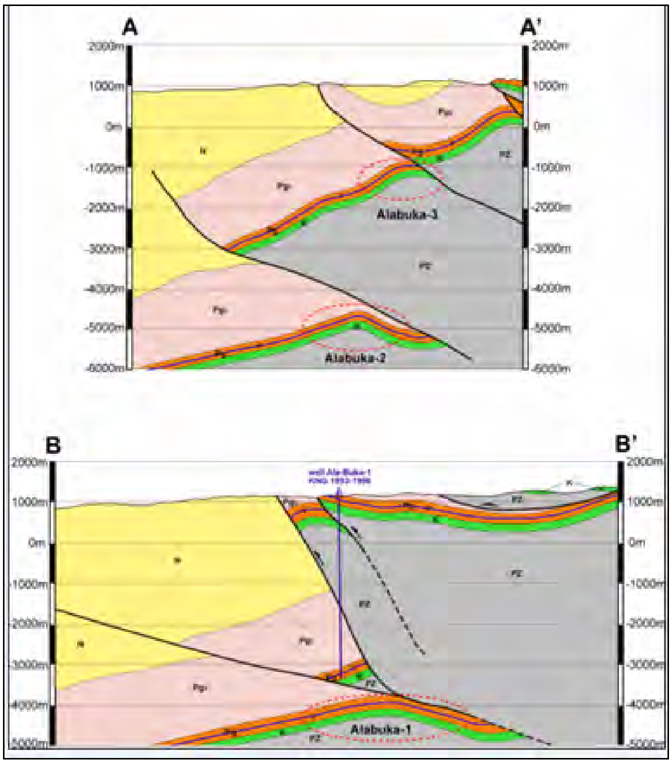


Figure 7 – Schematic Cross Sections across the Alabuka 2 & 3 structures (A- A') and Alabuka 1 structure (B-B')

The following figure illustrates the quality of the seismic data that is available to define these structures.

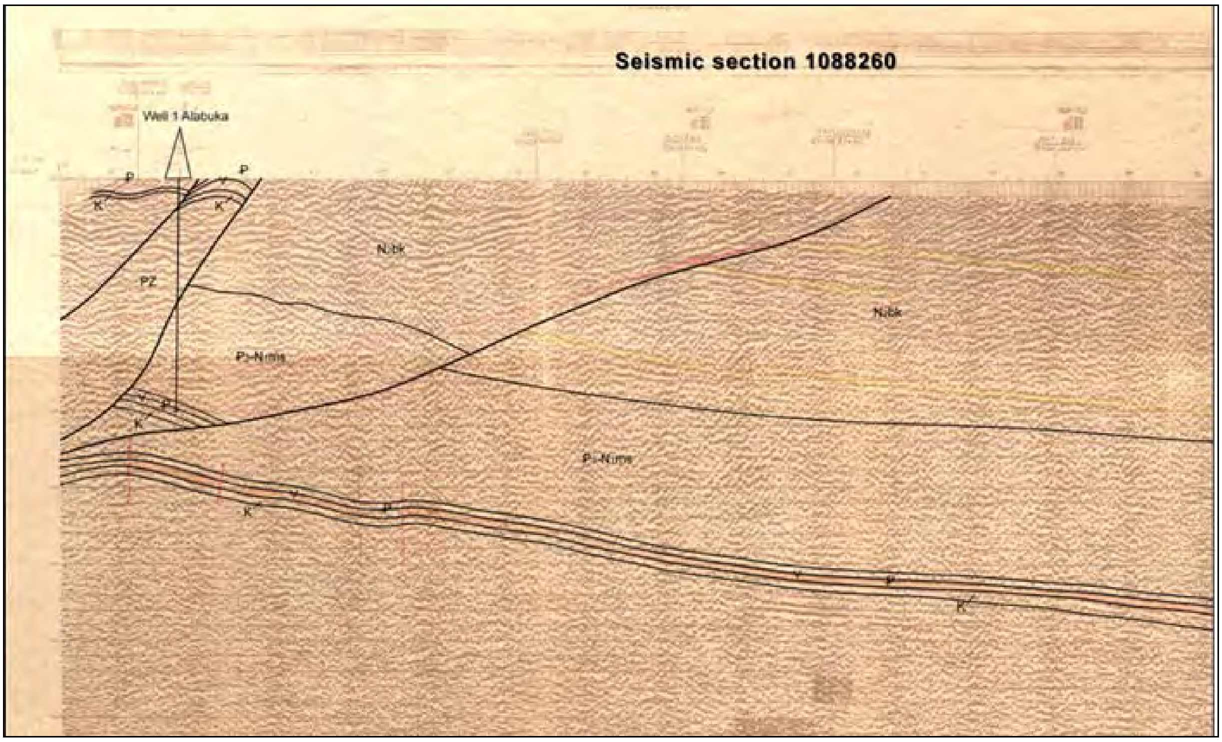


Figure 8 – Seismic line 1088260 across the Alabuka-1 structure

2.1.1. Alabuka-1 Prospect

The well Alabuka-1, drilled by KNG in 1993-1996 was aimed at a shallower target in the upper thrust sheet and did not penetrate into the lower thrust sheet. Seismic line 1088260 with DWM interpretation (see Figure 8) passes through this well and on towards the crest (as mapped) of the structure. The maps for these structures are in TWT only with no depth versions available. The well encountered in excess of 1000 metres of Palaeozoic rocks thrust over Palaeocene to Pliocene rocks. The affect of depth conversion through such complex overburden needs to be considered. Figure 9 shows the results of a one-line depth conversion (line 1088260) using a simple two-layer model (Palaeozoic and Cenozoic layers) above the target reservoir level.

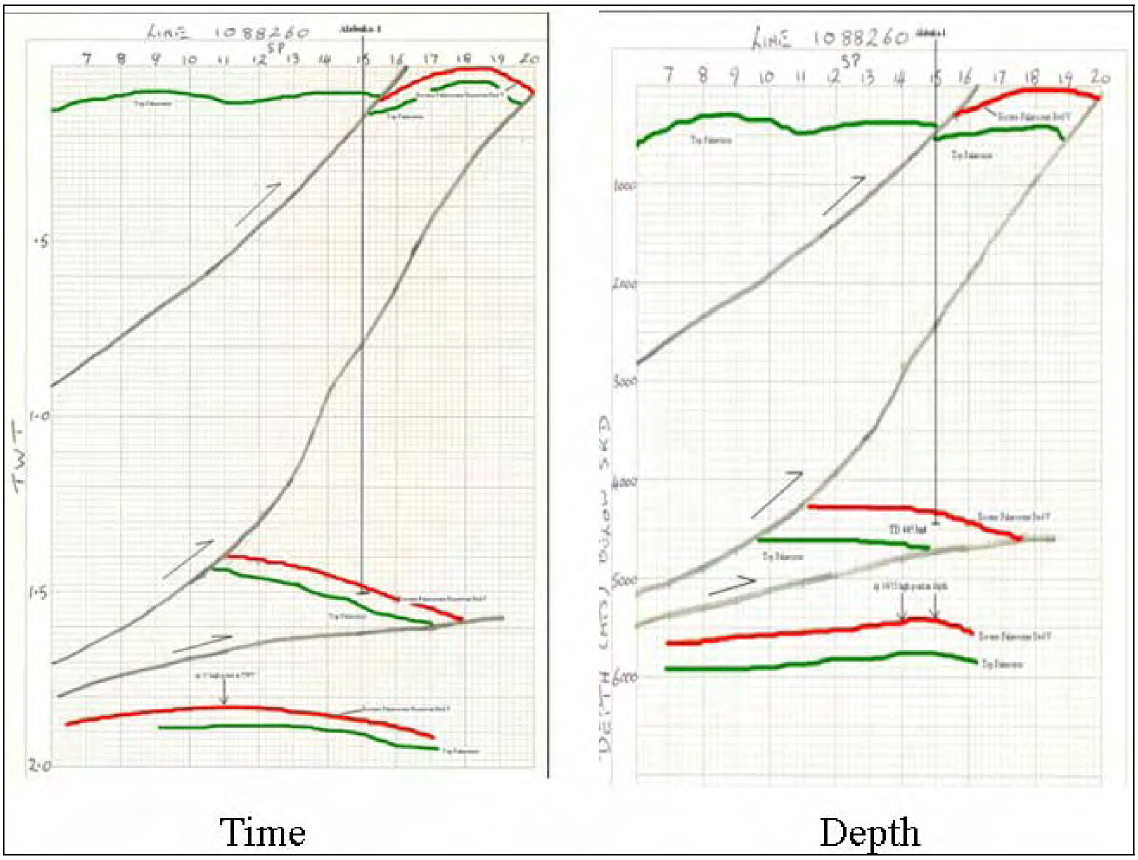


Figure 9 – Comparison of time and depth sections of line 1088260 across the Alabuka -1 structure

As no velocity survey was available for the well pseudo interval velocities were calculated using well depths and seismic times from the interpreted section. All depths quoted are below Seismic Reference Datum (SRD) that, in the absence of any information to the contrary, is assumed to be the same as the surface elevation of the well. If the current time interpretation and extrapolated contours are used it is likely that after depth conversion the structure will flatten and the crest (high point) on this line will shift southwards from shotpoint 11.5 to shotpoint 14.5. The depth conversion is correcting for both velocity pushdown, caused by the slower Cenozoic rocks on the southern flank, and for velocity pull-up, caused by the faster Palaeozoic rocks over the crest. This it must be stated is only a crude model and would need considerable refinement for detailed, pre-drill, mapping in depth. This example illustrates the fact that in addition to the acquisition and detailed processing of new seismic data there is also a need for caution and careful depth modelling in areas of complex, thrusted overburden. This statement applies not only to this structure but to all of the deeper thrust structures in the DWM portfolio.

Scott Pickford has reviewed the potential range in the reservoir parameters for this structure and has used these in a deterministic manner to calculate the range in possible STOIIP.

ALABUKA 1	VOLUMETRICS-OIL		
	Min	ML	Max
Area (km^2)	8.71	12.68	16.58
Net Thickness (m)	25	25	25
NRV (m^3 x 10^6)	87.1	126.8	165.8
Porosity (%)	20	20	20
Hydrocarbon Sat (%)	35	35	35
FVF	1.3	1.3	1.3
STOIIP (MMbbls)	**73.75**	**107.36**	**140.38**

Based on a gas-oil ratio of 330 Scott Pickford has calculated the range of associated gas to be as follows.

ALABUKA 1	VOLUMETRICS-GAS		
	Min	ML	Max
GIIP (Bcf)	**136.7**	**198.9**	**260.1**

Scott Pickford has estimated the Chance of Success of the Alabuka-1 prospect as follows;

Factor	Risk Value (%)
Source	80
Seal	80
Trap	40
Reservoir	80
Total	20.5 (1 in 4.9)

2.1.2. Alabuka-2 Prospect

There is little strong evidence on the available data to suggest that the target beds do, in fact, roll over under the thrust fault as suggested on the schematic cross section (Figure 7) as the lines are too short and the overall data quality is poor. Line 1089275 (Figure 10) is only available as a filtered stack and the pick and fault definition at reservoir level is highly unreliable. Therefore accordingly this prospect is regarded as very high risk.

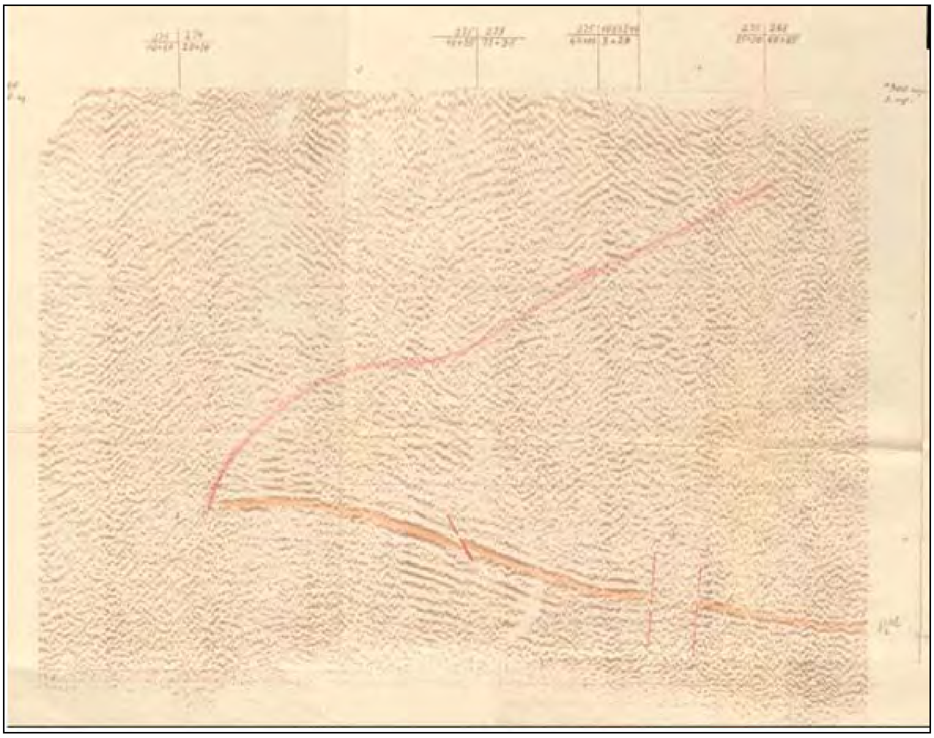


Figure 10 – Seismic line 1089275 across the Alabuka-2 structure

Scott Pickford has reviewed the potential range in the reservoir parameters for this structure and has used these in a deterministic manner to calculate the range in possible STOIIP.

ALABUKA- 2	**VOLUMETRICS-OIL**		
	Min	ML	Max
Area (km^2)	4.61	8.73	20.04
Net Thickness (m)	25	25	25
NRV (m^3 x 10^6)	46.1	87.3	200.4
Porosity (%)	20	20	20
Hydrocarbon Sat (%)	35	35	35
FVF	1.3	1.3	1.3
STOIIP (MMbbls)	**39.03**	**73.92**	**169.86**

Based on a gas-oil ratio of 330 Scott Pickford has calculated the range of associated gas to be as follows.

ALABUKA 2	**VOLUMETRICS-GAS**		
	Min	ML	Max
GIIP (Bcf)	**72.3**	**137.0**	**314.4**

Scott Pickford has estimated the Chance of Success of the Alabuka-2 prospect as follows;

Factor	Risk Value (%)
Source	80
Seal	80
Trap	25
Reservoir	80
Total	12.8 (1 in 7.8)

2.1.3. Alabuka-3 Prospect

Line 1089276 (Figure 11) shows evidence of steep dips that may define the Alabuka-3 structure in a wedge between the upper and lower thrust sheets

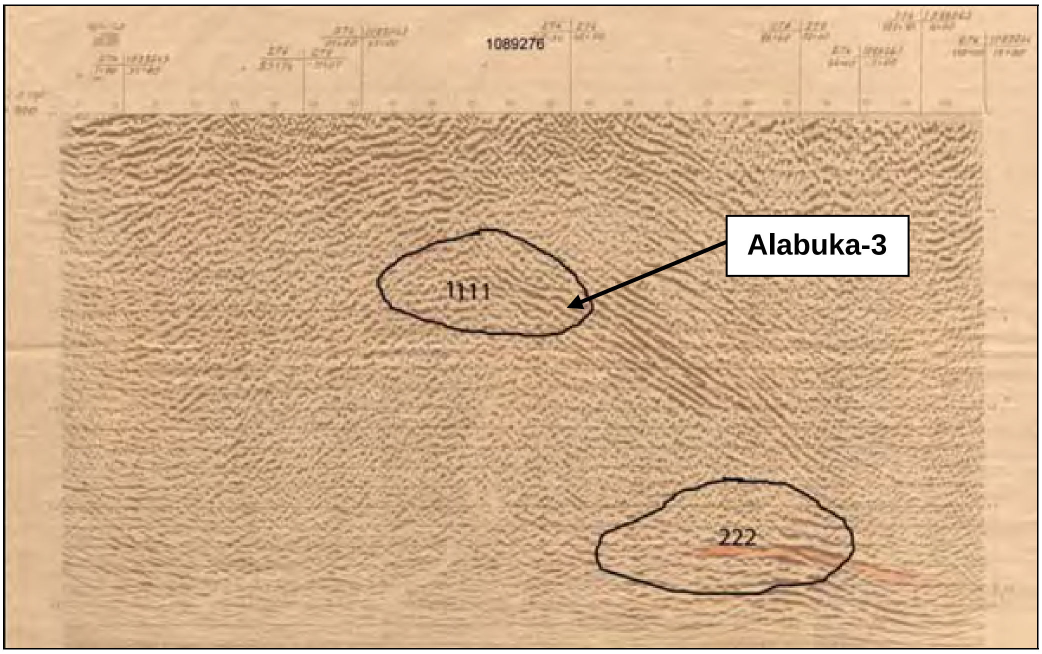


Figure 11 – Seismic line 1089276 showing possible position of the Alabuka-3 Prospect

Scott Pickford has reviewed the potential range in the reservoir parameters for this structure and has used these in a deterministic manner to calculate the range in possible STOIIP.

ALABUKA-3	**VOLUMETRICS-OIL**		
	Min	ML	Max
Area (km^2)	6.05	7.76	10.62
Net Thickness (m)	25	25	25
NRV (m^3 x 10^6)	60.5	77.6	106.2
Porosity (%)	20	20	20
Hydrocarbon Sat (%)	35	35	35
FVF	1.3	1.3	1.3
STOIIP (MMbbls)	**51.23**	**65.70**	**89.92**

Based on a gas-oil ratio of 330 Scott Pickford has calculated the range of associated gas to be as follows.

ALABUKA 3	**VOLUMETRICS-GAS**		
	Min	ML	Max
GIIP (Bcf)	**94.9**	**121.7**	**166.6**

This feature is poorly defined and as a result Scott Pickford has estimated the Chance of Success of this prospect as follows;

Factor	Risk Value (%)
Source	80
Seal	80
Trap	20

Reservoir	80
Total	10.2 (1 in 9.8)

2.2. Naushkent Prospecting Licence

The Naushkent PL is located in the northern zone of the Fergana Basin adjacent to the border with Uzbekistan to the south (see Figure 1). DWM do not currently have any seismic or well data in this licence. The only available data is an old Soviet map showing a closed structure (Figure 12) and therefore no volumetric estimates have been generated for this Licence.

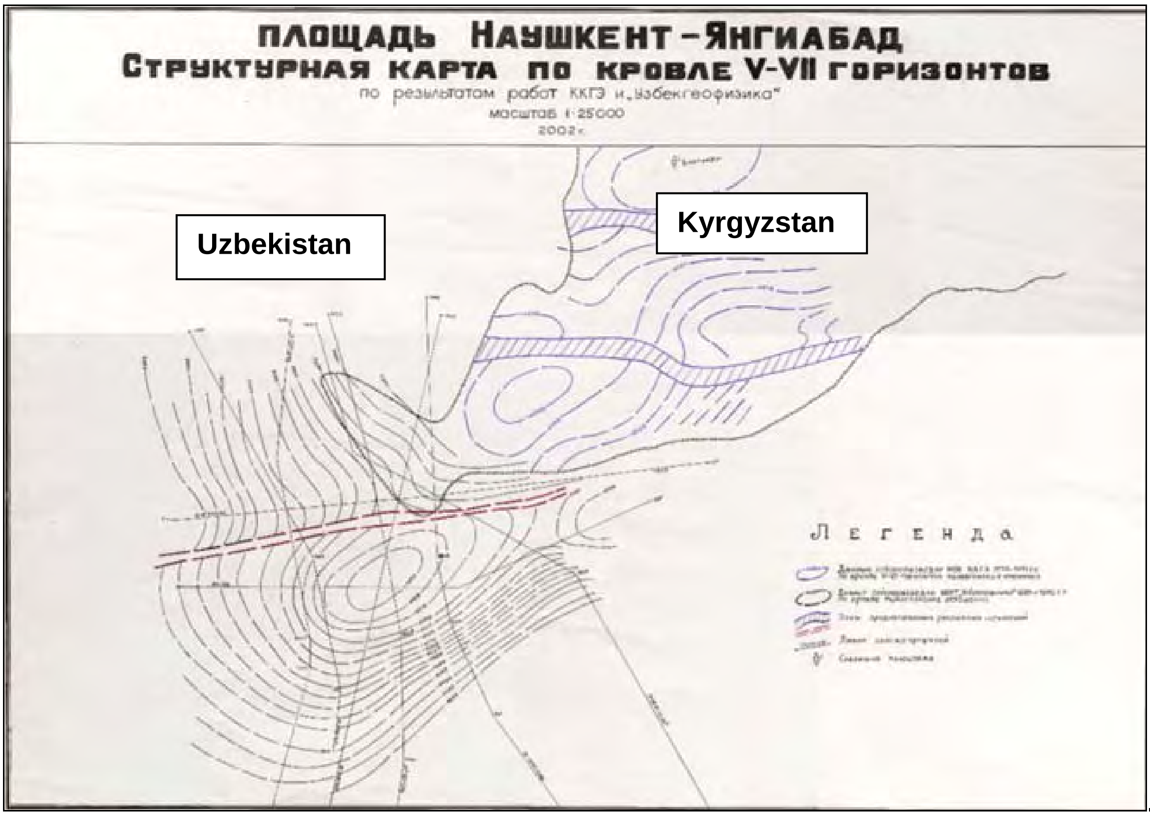


Figure 12 – Old Soviet Map showing the presence of a structure (blue contours)

2.3. Soh Prospecting Licence

The Soh PL is located in the southern zone of the Fergana Basin adjacent to the border with Uzbekistan to the north (see Figure 1). Two deep lower thrust sheet structures called Burdalyk and Kyzyl Kurgan have been identified by DWM and have been reviewed by Scott Pickford. A number of other structures have also been identified these include un-drilled fourway dip closures at the upper thrust sheet level (Katran, Kan) and a shallow structure with a topseal provided by a tar mat (West Chaur). There are several producing oil and gas fields within the region that are excluded from the prospecting Licence (see Figure 13). These fields which are shown in pale blue in Figure 13 below have production from the upper thrust sheet. The seismic database consists of eleven dip and four strike lines. Of these lines only seven are relevant to the Kyzyl Kurgan structure and none relate to the Burdalyk structure (see Figure 14). Data from the North Soh field indicates that in this area the Oligocene and Eocene pay beds are predominantly oil prone (with the exception of Bed VII) and that the Cretaceous pay beds are predominantly gas prone. Consequently in our resource calculations Scott Pickford has determined separate volumes for the gas in the lower zones and has not taken into consideration the upside volumes of associated gas that may be produced along with the oil.

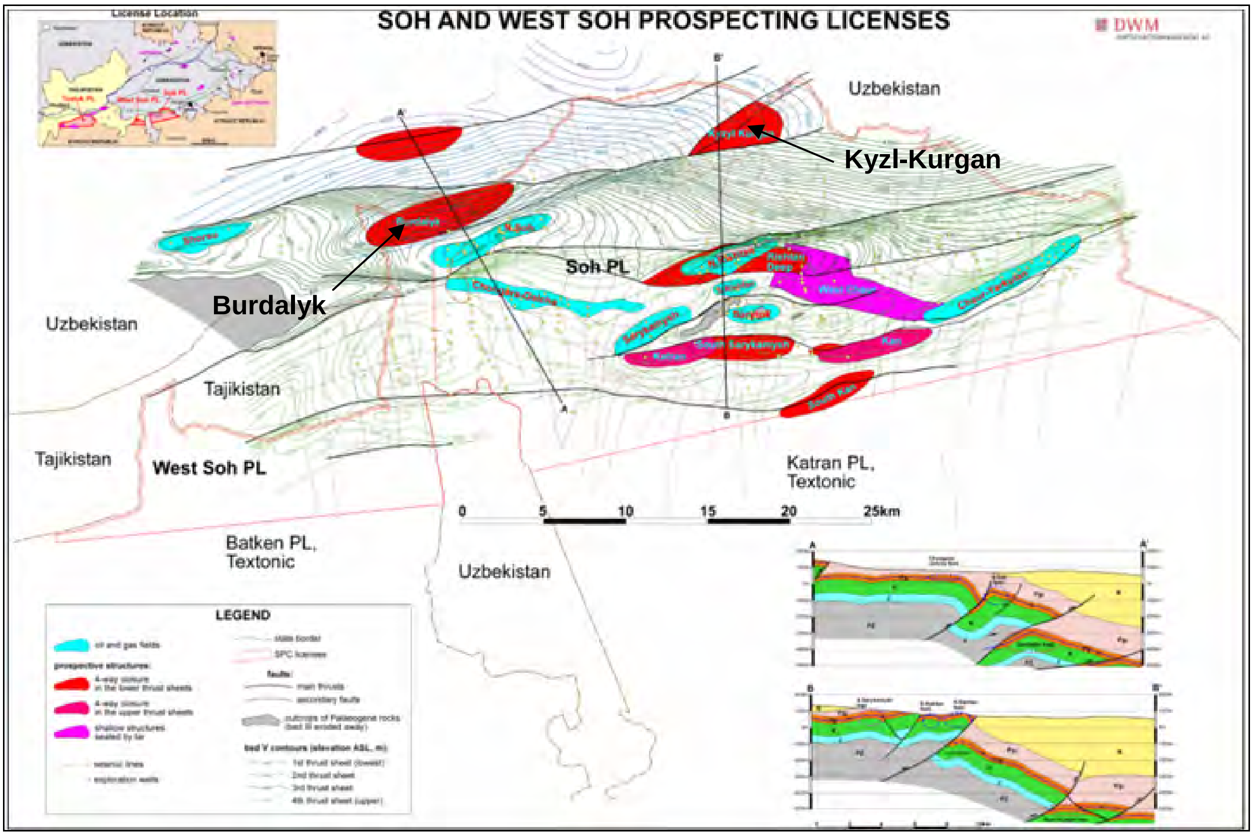


Figure 13 – Prospects identified in the Soh and West Soh Licences

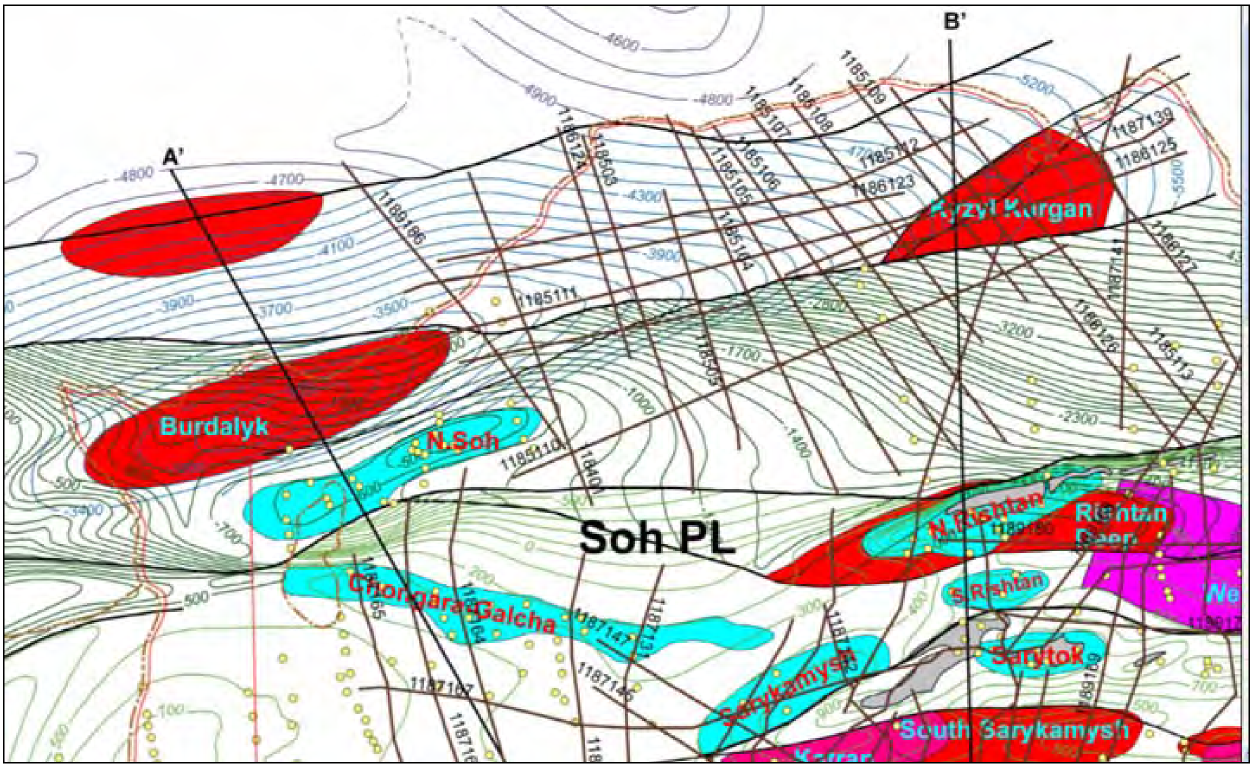


Figure 14 – Seismic coverage over the Burdalyk and Kyzyl-Kurgan Prospects

2.3.1. Burdalyk Prospect.

The Burdalyk structure that lies partly in Uzbekistan (see Figure 15) has been mapped in depth, at the marker bed Eocene V level. It appears to be a simple anticline located beneath a thrust sheet. However DWM does not have access to the relevant seismic data and the map has been depth converted using the simplistic methodology previously discussed. Three deep wells have been drilled by the Uzbeks on the eastern plunge of the anticline and two of these wells, BD-1 and 2, have apparently encountered an oil water contact in the Eocene. A portion of this prospect lies within Uzbekistan the magnitude of this portion is dependent on the prospect extent assumed.

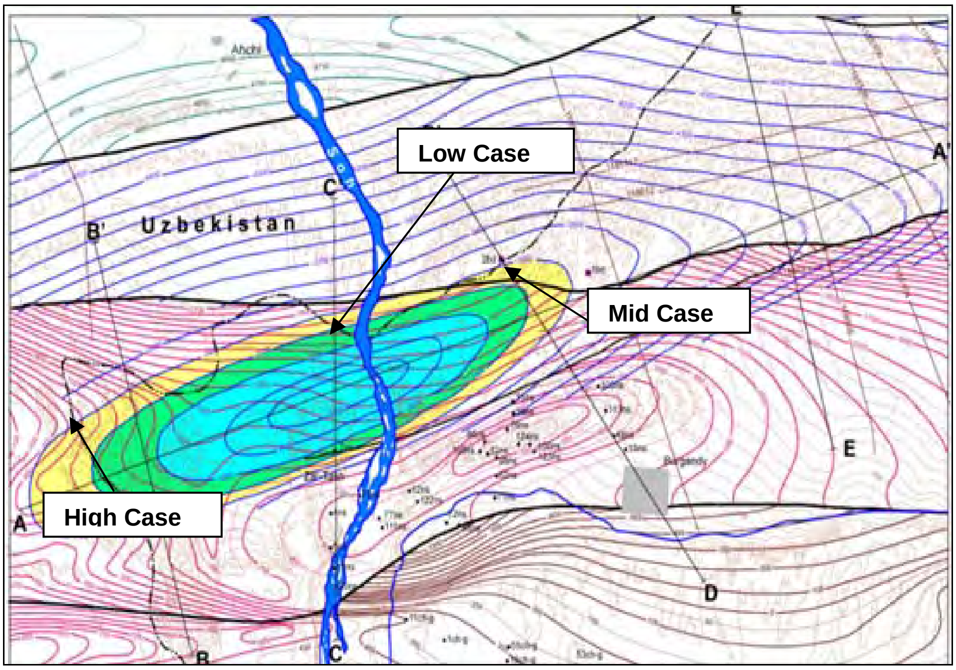


Figure 15 – Map showing the range of possible extent of the Burdalyk Prospect

With the currently available data it is not possible to define the dimensions of this structure, however Scott Pickford has made an attempt to place an overall limit to the size range and the results are presented below.

BURDALYK	**VOLUMETRICS-OIL**		
	Min	ML	Max
Area (km^2)	9.47	16.59	25.46
Net Thickness (m)	30	30	30
GRV (m^3 x 10^6)	284.1	497.7	763.8
Porosity (%)	0.2	0.2	0.2
Hydrocarbon Sat (%)	0.7	0.7	0.7
FVF	1.1	1.1	1.1
STOIIP (MMbbls)	**227.43**	**398.42**	**611.44**

Scott Pickford has calculated the range of gas resources to be as follows.

BURDALYK	**VOLUMETRICS-GAS**		
	Min	ML	Max
1/Bg	230	230	230
GIIP (Bcf)	**24.01**	**42.06**	**64.55**

This feature is poorly defined and as a result Scott Pickford has estimated the Chance of Success of this prospect as follows;

Factor	Risk Value (%)
Source	90
Seal	80
Trap	40
Reservoir	80
Total	23 (1 in 4.3)

2.3.2. Kyzyl Kurgan Prospect

The Kyzyl Kurgan structure (see Figures 16 and 17) has been mapped in depth at the Eocene marker bed V level using the same depth conversion methodology as elsewhere. The seismic coverage is relatively good with five dip and two strike lines over the structure. However, the feature is complex and is mapped as a tectonic wedge between thrusts with opposite transport direction. The current data is of insufficient quality to allow high confidence in this interpretation as it is difficult to separate primary reflections from multiple energy and fault plane reflections. Nevertheless, although somewhat model driven, the overall structural form is confirmed by the data. A seismic line is shown in Figure 18 although the origin of the interpretation marked is not known.

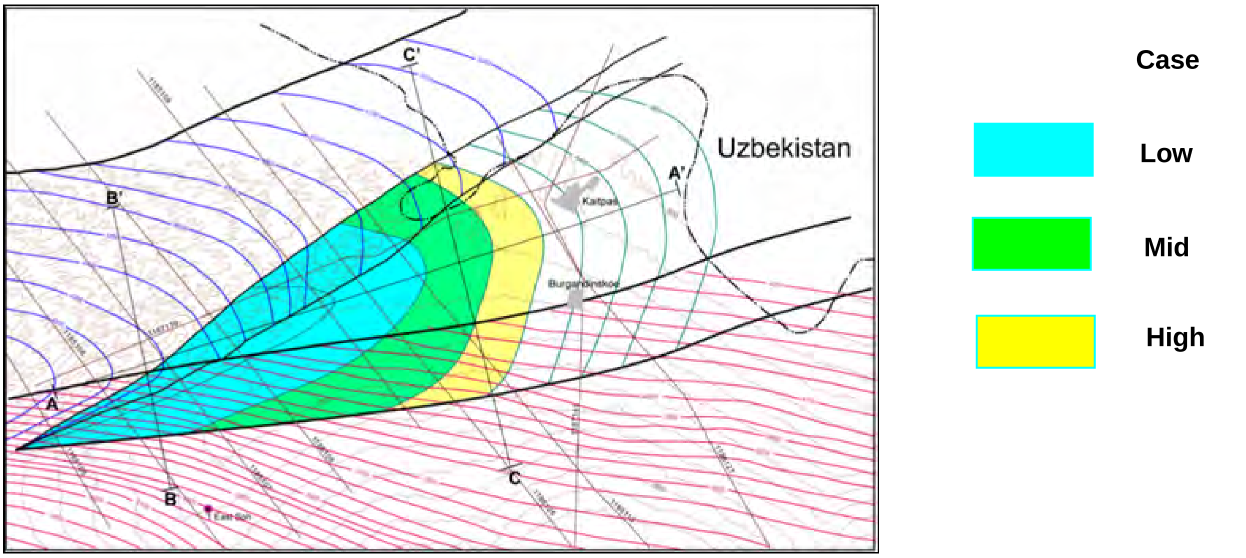


Figure 16 – Depth Structure map of the Kyzyl-Kurgan Prospect

Figure 17 shows a series of schematic cross sections through the Kyzyl-Kurgan Prospect and illustrate the complex nature of the structure.

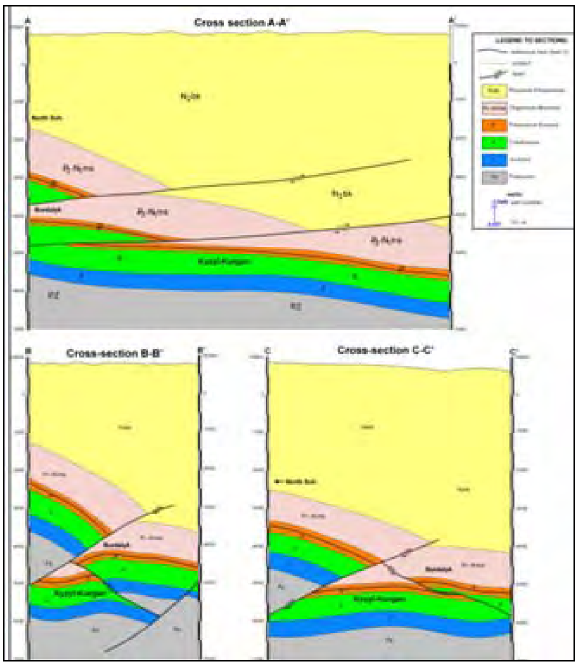


Figure 17 – Schematic Cross Sections through the Kyzyl-Kurgan Prospect

Figure 18 shows an example seismic line through the Kyzyl-Kurgan structure and the degree of complexity associated with it.

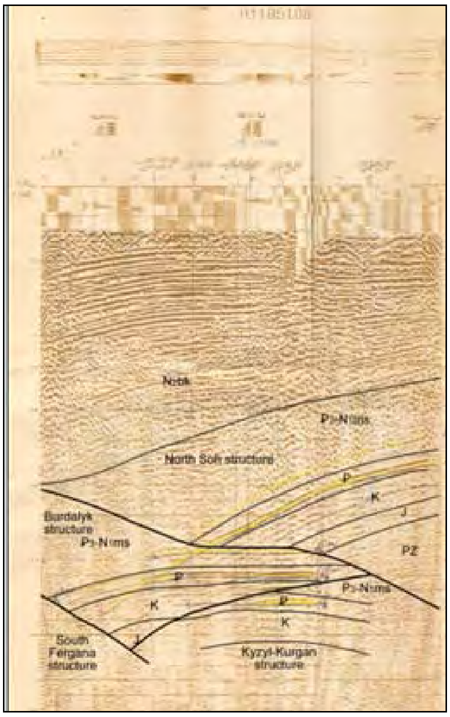


Figure 18 – Seismic line 1185108 across the Kyzyl-Kurgan Prospect

Scott Pickford has reviewed the potential range in the reservoir parameters for this structure and has used these in a probabilistic manner to calculate the range in possible STOIIP.

KYZYL-KURGAN	**VOLUMETRICS-OIL**		
	Min	ML	Max
Area (km^2)	8.13	13.58	19.96
Net Thickness (m)	22	22	22
NRV (m^3 x 10^6)	178.86	298.76	439.12
Porosity (%)	0.2	0.2	0.2
Hydrocarbon Sat (%)	0.45	0.45	0.45
FVF	1.13	1.13	1.13
STOIIP (MMbbls)	**89.60**	**149.67**	**219.98**

Scott Pickford has calculated the range of gas resources to be as follows.

KYZYL-KURGAN	**VOLUMETRICS-GAS**		
	Min	ML	Max
1/Bg	230	230	230
GIIP (Bcf)	**9.20**	**15.37**	**22.59**

Although this feature is well covered with seismic data the degree of structural complexity is such that there is still considerable uncertainty with regards to structural definition and as a result Scott Pickford has estimated the Chance of Success of this prospect as follows;

Factor	Risk Value (%)
Source	90
Seal	80
Trap	40
Reservoir	80
Total	23 (1 in 4.3)

2.3.3. Other Leads

In addition to those structures described above, DWM have identified several other leads within this Licence (see Figure 13). These include Rishtan Deep, which lies partly below the North Rishtan field, South Sarykamysh, South Kan and the shallow West Chaur, which lies between, and at the same stratigraphic level as, the North Rishtan and Chaur-Yarkutan fields. However, there is very little data available currently on these features and therefore only West Chaur is considered as a potential drilling target at this time with the others being regarded as conceptual plays at this time.

WEST CHAUR	**VOLUMETRICS-OIL**		
	Min	ML	Max
Area (km^2)	21.5	21.93	22.5
Net Thickness (m)	10	10	10
NRV (m^3 x 10^6)	215	219.3	225
Porosity (%)	20%	20%	20%
Hydrocarbon Sat (%)	50%	50%	50%
FVF	1.1	1.1	1.1
STOIIP (MMbbls)	122.94	125.40	128.66

Scott Pickford has calculated the range of gas resources assuming a GOR of 40 to be as follows.

WEST CHAUR	**VOLUMETRICS-GAS**		
	Min	ML	Max
1/Bg	41	42	43

Scott Pickford has estimated the Chance of Success of the West Chaur lead as follows;

Factor	Risk Value (%)
Source	90
Seal	90
Trap	70
Reservoir	90
Total	51% (1 in 2)

2.4. West Soh Prospecting Licence

The West Soh PL is located in the southern zone of the Fergana Basin adjacent to the border with Tajikistan to the north (see Figure 1). No data is available in the West Soh PL and as a result no structures have been identified.

2.5. Tuzluk Prospecting Licence

The Tuzluk PL is located in the southern zone of the Fergana Basin adjacent to the border with Tajikistan to the north (see Figure 1). There are a number of established oilfields in this area (Beshkent-Togap, Tashravat, Tamchi, Karagachi) that have produced from the upper thrust sheet their location is shown in pale blue on Figure 19. These fields are excluded from the exploration Licence held by DWM. More significant for the exploration potential is the presence of the North Karakchikum field which straddles the Tajikistan/Kyrgyzstan border and is analogous to the South and West Tuzluk prospects. Five structures called Selkan, Arka, West Tuzluk, South Tuzluk and the Tashravat Monocline have been identified and reviewed by Scott Pickford. The seismic database which is relatively large but rather uneven in coverage will be discussed in more detail under the description of each structure.

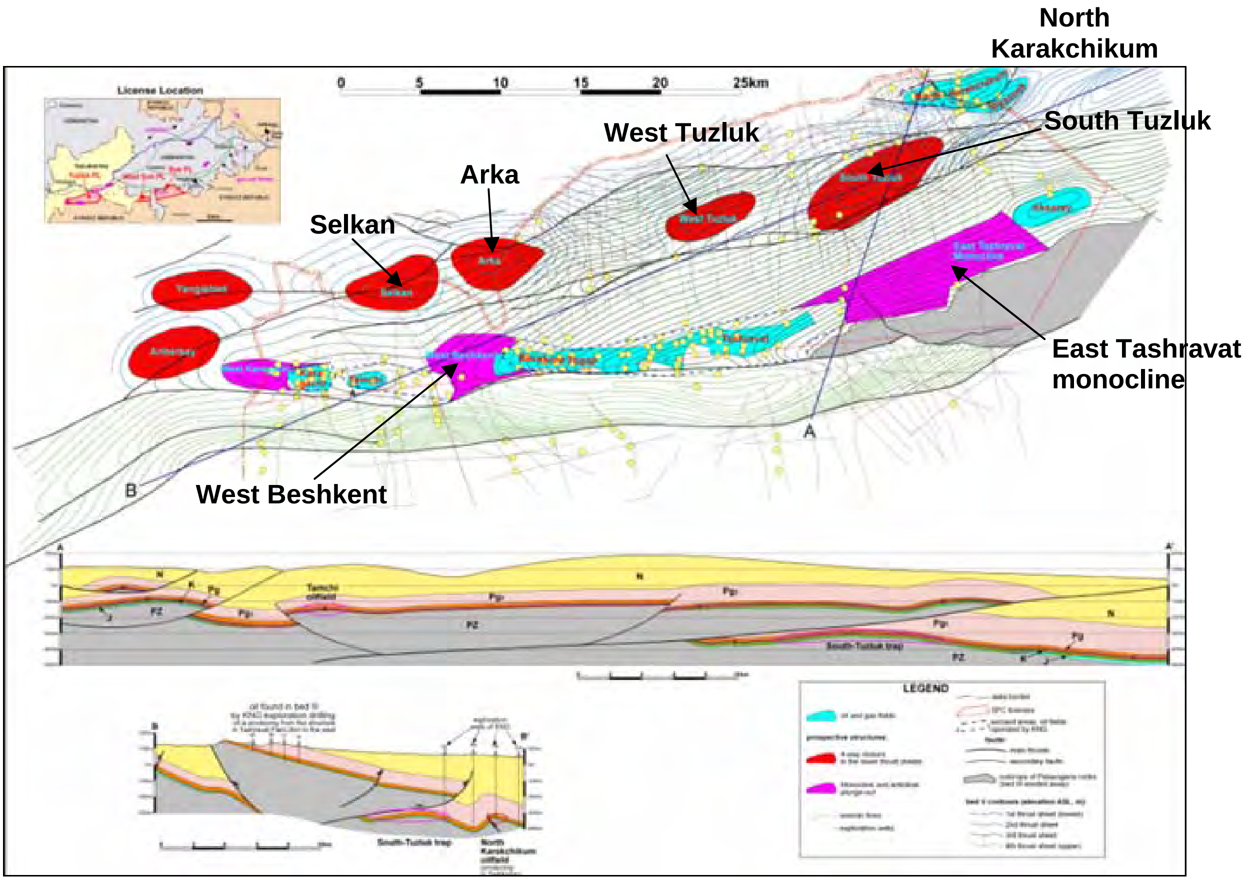


Figure 19 – Existing Fields and Prospects in the Tuzluk Licence area

2.5.1. South Tuzluk Prospect

The South Tuzluk structure (see Figures 20 and 21) has been mapped in depth at the Eocene marker bed V level and appears as a simple anticline located beneath the thrust sheet. Depth conversion was achieved by the same simplistic methodology as described previously. The seismic coverage is good with ten dip and four strike lines located over the structure. However, data quality is insufficient for accurate mapping of the entire structure. Ten wells have been drilled in the area, the majority outside of the mapped closure, and have established the presence of reservoir beds beneath the thrust. Well CTZ-5 reported oil in beds beneath the marker bed V (upper beds were not tested) and well CTZ-1 is reported to be at the oil/water contact (OWC) in bed III located above the marker horizon Figure 21 shows an (unknown) interpretation of line 0376035 (in two-way-time) that passes through wells CTZ-1 and 5. This line clearly demonstrates that, after depth conversion, the structure should be shifted southwards to accommodate the well results.

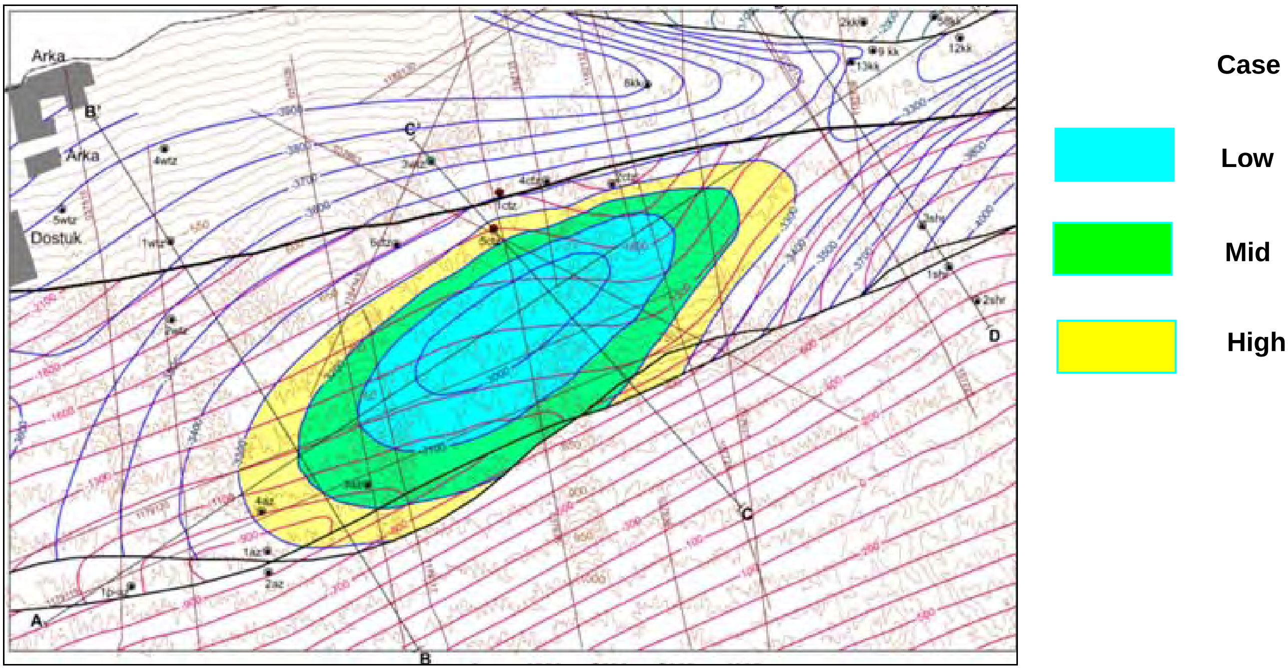


Figure 20 – Depth map of the South Tuzluk Prospect

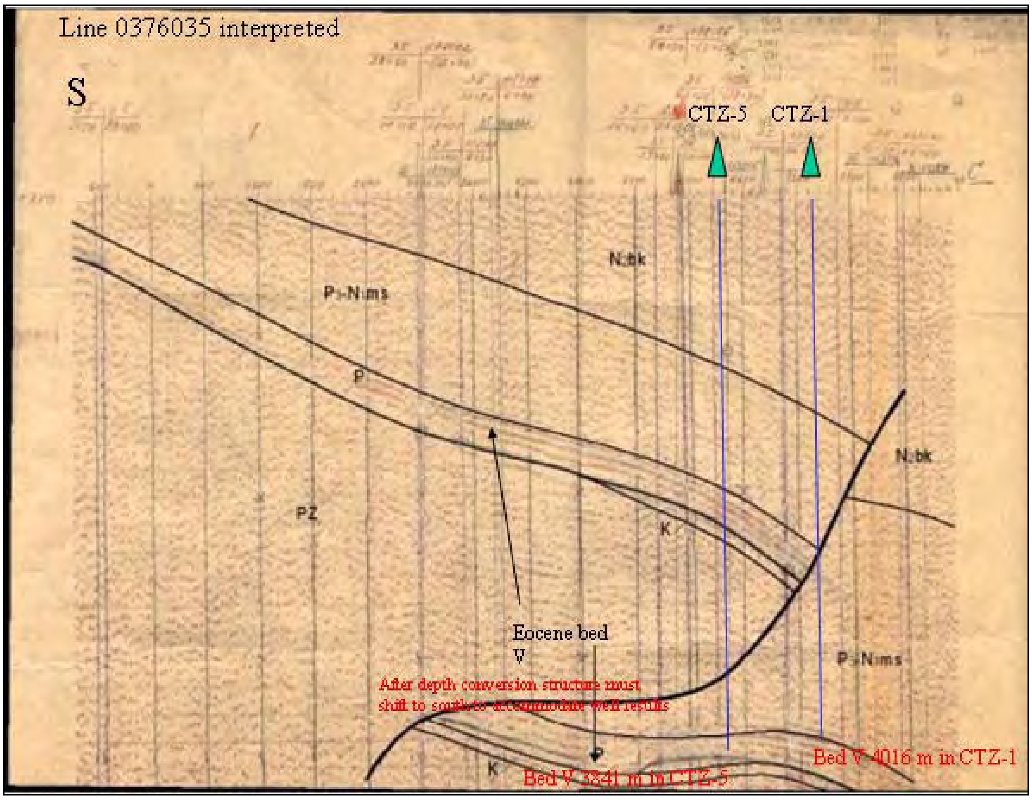


Figure 21 – Seismic line 0376035 across the South Tuzluk Prospect (interpretation – origin unknown)

Scott Pickford has reviewed the potential range in the reservoir parameters for this structure and has used these in a probabilistic manner to calculate the range in possible STOIIP.

SOUTH TUZLUK	**VOLUMETRICS-OIL**		
Area (km^2)	8.79	17.01	24.9
Net Thickness (m)	12.1	12.1	12.1
GRV ($m^{3} \times 10^{6}$)	106.36	205.82	301.29
Porosity (%)	17.83	17.83	17.83
Hydrocarbon Sat (%)	61	61	61
FVF	1.1	1.1	1.1
STOIIP (MMbbls)	**66.69**	**129.05**	**188.91**

SOUTH TUZLUK	**VOLUMETRICS-GAS**		
	Min	ML	Max
1/Bg	230	230	230
GIIP (Bcf)	**14.65**	**22.43**	**31.81**

Scott Pickford has estimated the Chance of Success of the South Tuzluk prospect as follows;

Factor	Risk Value (%)
Source	90
Seal	80
Trap	40
Reservoir	80
Total	23 (1 in 4.3)

2.5.2. West Tuzluk Prospect

The West Tuzluk structure (see Figure 22) has been mapped in depth at the Eocene marker bed V level, and appears as a simple anticline located beneath the thrust sheet. Depth conversion was achieved by the same simplistic methodology as described previously. The seismic coverage is relatively good with seven dip and five strike lines in the vicinity of the structure. However, the data quality is very poor and the structure is only visible on one line 037630. Five wells have been drilled to the target level in the vicinity of West Tuzluk, and have established the presence of reservoir beds beneath the thrust sheet. None of these wells to date appear to have been drilled within the currently mapped closure.

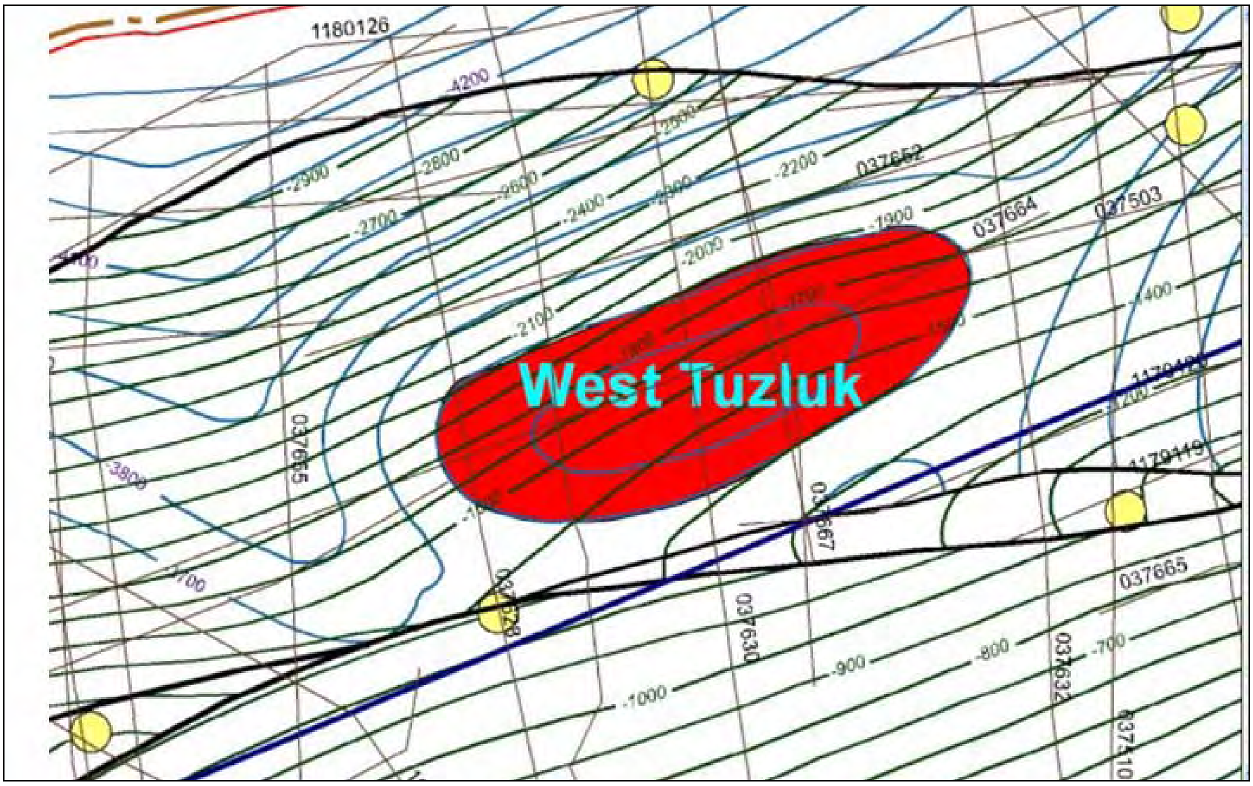


Figure 22 – Map showing the areal extent of the West Tuzluk Prospect and seismic coverage

Scott Pickford has reviewed the potential range in the reservoir parameters for this structure and has used these in a probabilistic manner to calculate the range in possible STOIIP.

WEST TUZLUK	**VOLUMETRICS-OIL**		
	Min	ML	Max
Area (km^2)	3.38	6.54	9.69
Net Thickness (m)	12.1	12.1	12.1
GRV (m^{3} x 10^{6})	40.90	79.13	117.25
Porosity (%)	17.8	17.8	17.8
Hydrocarbon Sat (%)	61	61	61
FVF	1.1	1.1	1.1
STOIIP (MMbbls)	**25.64**	**49.62**	**73.52**

WEST TUZLUK	**VOLUMETRICS-GAS**		
	Min	ML	Max
1/Bg	230	230	230
GIIP (Bcf)	**7.64**	**14.79**	**21.91**

Scott Pickford has estimated the Chance of Success of the West Tuzluk prospect as follows;

Factor	Risk Value (%)
Source	90
Seal	80
Trap	25
Reservoir	80
Total	14.4 (1 in 6.9)

2.5.3. Selkan and Arka Leads

The Selkan and Arka structures (see Figures 23 and 24) have been mapped in depth, at the marker bed Eocene V level and appear to be simple anticlines located beneath a thrust sheet. DWM has access to only a limited amount of seismic data that does not cover the Selkan structure and only just touches the flank of the Arka structure. The identification of these structures thus relies heavily on analogies to proven structures mapped in Tajikistan to the north. The structure map has been depth converted using the same simplistic methodology as previously discussed. The two structures are only separated by one contour and therefore a relatively small change in the depth conversion could result in the structures merging in to one larger feature. Two deep wells (Auchi-Kalachi 1 and 2) have been drilled on the northern flank of the anticline and apparently confirm the presence of water wet reservoir beds in the Eocene. As the dimensions of these structures cannot be verified on seismic they have been treated as conceptual at this time.

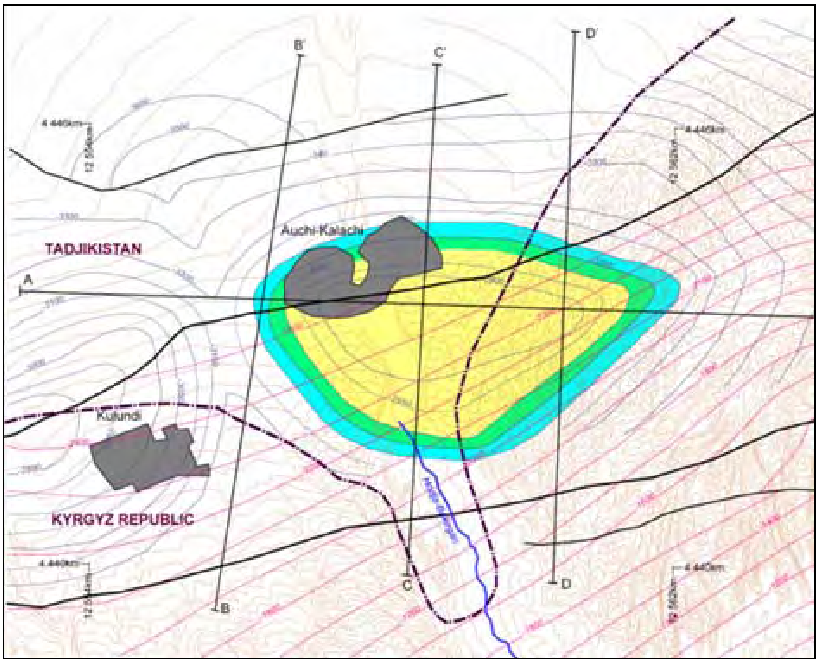


Figure 23 – Depth map of the Arka Lead

As currently mapped only about 40% of the Arka lead is in the DWM Licence the remaining 60% is located in Tajikistan.

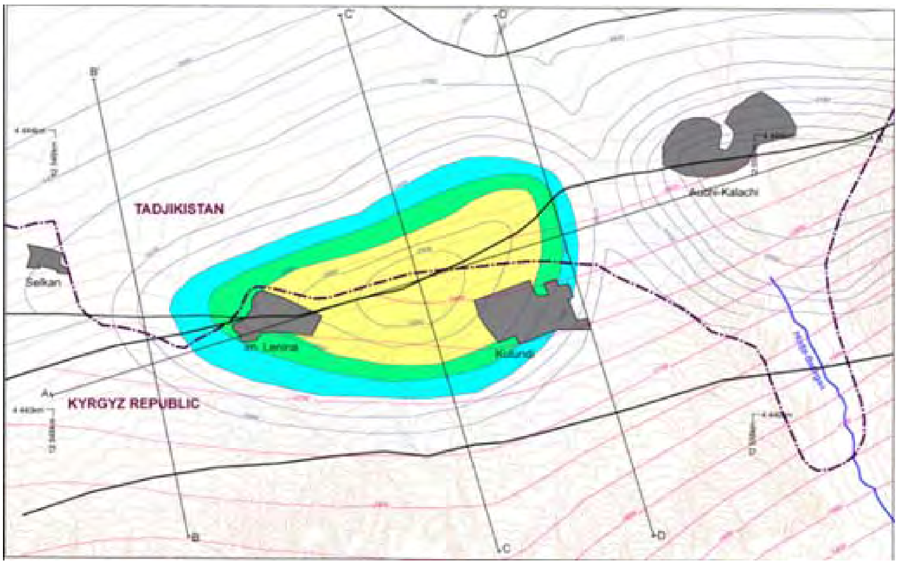


Figure 24 – Depth map of the Selkan Lead

As currently mapped only about 50% of the Selkan lead is in the DWM licence the remaining 50% is located in Tajikistan.

Currently the resource estimates for the Selkan and Arka leads are based on a pro rata volumetric yield taken from the predictions from the nearby South and West Tuzluk prospects and are estimated (P50) at 18.5MMbbls for Arka and 17.7MMbbls for Selkan.

2.5.4. East Tashravat Monocline

The East Tashravat Monocline (see Figure 25) is mapped in depth at the Eocene marker bed V level. The reservoir beds outcrop at surface just to the south of the end of line 0376035 and dip gently northwards as shown in Figure 26. The estimated depth to target is 300-800m below surface. Until recently this area has been excluded from any exploration activity due to uranium mining activities, however this has now ceased and exploration is permissible. Two wells have been drilled into the western part of the structure and the Aksaray field and the Tashravat oilfield, which have over 20 production wells, lie immediately to the east and west respectively. It is reasonable to assume that there should be no significant change in lithology, or the continued presence of a competent up-dip seal between these two fields. Therefore the Monocline would appear to be directly on trend with current production and simply requires additional seismic definition prior to drilling.

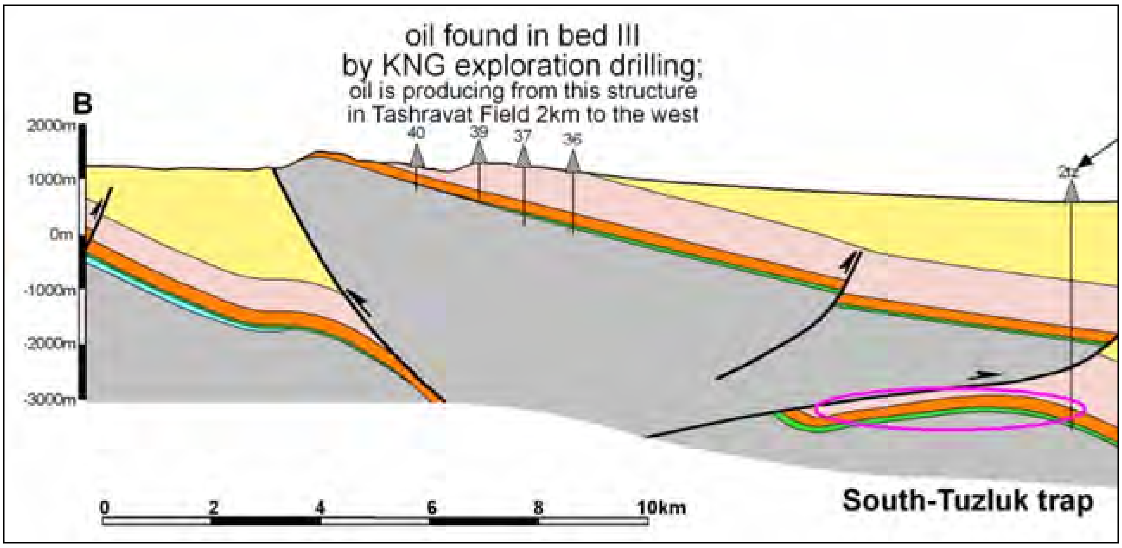


Figure 25 – Schematic cross section through the East Tashravat Monocline

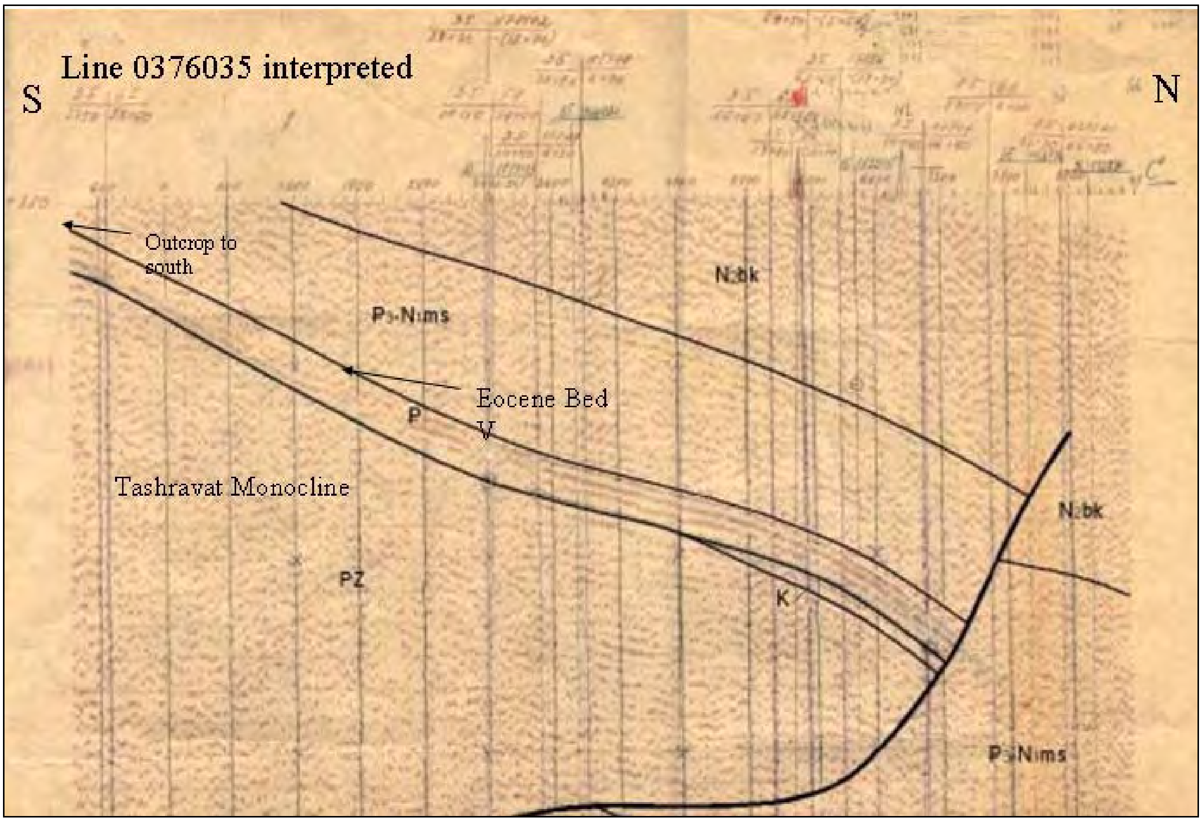


Figure 26 – Seismic line 0376035 across the East Tashravat Monocline

Scott Pickford has reviewed the potential range in the reservoir parameters for this structure and has used these in a probabilistic manner to calculate the range in possible STOIIP.

EAST TASHRAVAT MONOCLINE – VOLUMETRICS-OIL			
	Min	ML	Max
Area (km^2)	38	39.65	40
Net Thickness (m)	3	3.5	4
NRV ($m^3 \times 10^6$)	114	138.8	160
Porosity (%)	17%	19%	22%
Hydrocarbon Sat (%)	60%	62%	64%
FVF	1.12	1.12	1.12
STOIIP (MMbbls)	**65.30**	**91.81**	**126.52**

Based on gas-oil ratio of 40 Scott Pickford has calculated the range of gas resources to be as follows.

EAST TASHRAVAT MONOCLINE - VOLUMETRICS-GAS			
	Min	ML	Max
1/Bg	230	230	230
GIIP (Bcf)	**14.67**	**20.62**	**28.42**

Scott Pickford has estimated the Chance of Success of the East Tashravat Prospect as follows;

Factor	Risk Value (%)
Source	90
Seal	50
Trap	80
Reservoir	90
Total	32.4 (1 in 3.1)

2.5.5. Other Leads

A number of other leads located within the upper thrust sheet have also been recognised. These leads consist primarily of undrilled extensions to existing fields and are therefore considered to be low risk. The most significant of these leads is currently thought to be West Beshkent and volumes for this lead are presented below.

WEST BESHKENT – VOLUMETRICS-OIL			
	Min	ML	Max
Area (km^2)	13	13.6	14
Net Thickness (m)	3	3.5	4
NRV ($m^3 \times 10^6$)	39	47.6	56
Porosity (%)	17%	19%	22%
Hydrocarbon Sat (%)	60%	62%	64%
FVF	1.12	1.12	1.12
STOIIP (MMbbls)	**22.34**	**31.49**	**44.28**

Based on gas-oil ratio of 40 Scott Pickford has calculated the range of gas resources to be as follows.

WEST BESHKENT - VOLUMETRICS-GAS			
	Min	ML	Max
1/Bg			
GIIP (Bcf)	**5.02**	**7.07**	**9.95**

Scott Pickford has estimated the Chance of Success of the West Beshkent lead as follows;

Factor	Risk Value (%)
Source	90
Seal	90
Trap	70
Reservoir	90
Total	51% (1 in 2)

3. Reservoir Engineering

The available production data from nearby fields is limited to that from North Karachikum-Niazbek field in the Tuzluk licence. This field began production in 1974 and remained in production until 1988 when a lack of operating funds caused the field to be shutdown. The average well production profile is shown in Figure 27 from which it can also be noted that the initial flow rate was in the order of 275bbls/day. It is expected that with modern western drilling and completion technology that this flow rate will be greatly exceeded.

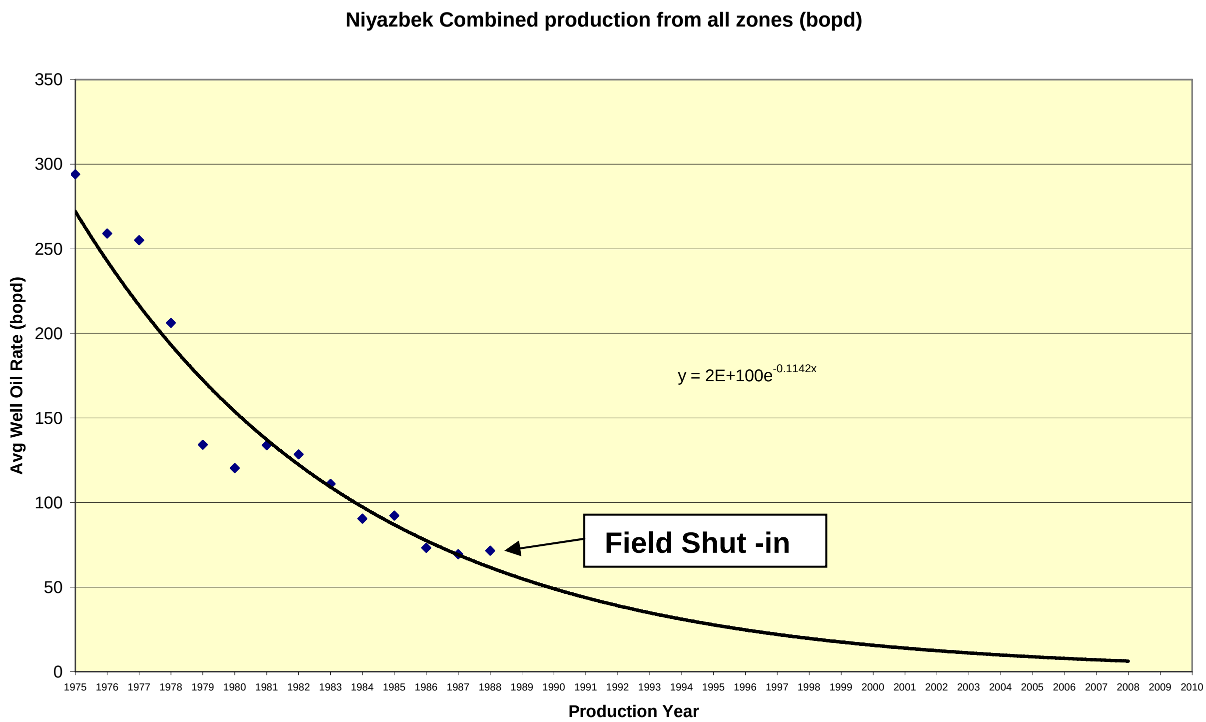


Figure 27 – Average Oil Production Rate per well in the North Karachikum-Niazbek field

In order to make estimates of what future well production rates might be in new developments Scott Pickford has assumed a base case profile based loosely on the North Karachikum-Niazbek with an initial production rate of 300bbls/day and a decline rate of 20% per annum. A number of upside cases have also been assumed as follows:

1) Initial production rate of 1000bbbls/day with 22.5% decline
2) Initial production rate of 2000bbbls/day with 22.5% decline

The production profiles for these individual well cases are shown in Appendix B. It has been assumed that the theoretical recovery efficiency will be 20% in the natural depletion cases. Production profiles for individual prospects have been generated by calculating the number of wells required to drain the most likely STOIIP and assuming that wells will be brought onstream at a rate of between 4-18 wells per year. For the shallow prospects it has been assumed that the 2000bbls/d initial production rate case is not realistic and therefore only the 1000bbls/d case has been considered as an upside scenario.

Scott Pickford has also investigated the possible benefits of implementing a water injection programme to provide reservoir pressure support. If a basic assumption is made that the decline rate can be reduced to 15% per annum and that an additional rig can be mobilised to drill the injection wells then increased recoveries of the order of 30-35% can be achieved. It must be emphasised at this stage that it is not possible to state that the above mentioned assumptions can be met, however they are consistent with those achieved in many fields around the world. It has been assumed that water injection would begin at the start of field life. Production profiles have been generated for the same range of well initial flowrates as in the natural depletion development scenario. The profiles generated are thus highly conceptual in nature and require verification with actual field data when this becomes available.

For gas production the North Karachikum-Niazbek production data was examined and a base case profile with an initial production rate of 2MMcfd and a decline rate of 20% per annum. An upside case profile an initial production rate of 5MMcfd and a decline rate of 20% per annum has been used as a sensitivity.

4. Economics

4.1. Introduction

Separation and storage facilities for oil are already in existence at several railway loading stations situated close to current production. These facilities will be available for use for new production and therefore it will only be necessary to install flowlines to these localities. Once at the railway loading stations the oil will be shipped either to the refinery or exported. There is one refinery in Kyrgyzstan operated by Petrofac. Currently this refinery is operating at only 12% of its ultimate capacity which is 15,000bopd although it would be relatively straightforward to upgrade this capacity should production outstrip this. The refinery will pay an equivalent price to that which would be obtained from export of the oil.

The situation with regards to gas demand in Kyrgyzstan is that currently Kyrgyzstan consumes between 28-35Bcf of gas per year whilst it only produces in the region of 1Bcf, the balance is imported. In the southern region of Kyrgyzstan close to the DWM licences annual consumption is around 3.5Bcf. In addition to the gas demand in Kyrgyzstan neighbouring Tajikistan (specifically the Sogdiy district) consumes 7Bcf of gas per year all of which is imported from Uzbekistan. Tajikistan would much prefer to import this gas from Kyrgyzstan. The total annual gas consumption in Tajikistan taken from government sources is between 25-28Bcf and annual production is only in the region of 1.3Bcf. In the Tuzluk area a short pipeline (approx. 7km in length) would be required to transport the gas to the gas compression station on the Gazly-Ferghana pipeline. This pipeline would cost around $0.5MM. In the Soh licence area gas distribution infrastructure (owned and operated by KNG) is in place and passes close to the identified prospects. Gas produced in this area would be sold domestically to a mixture of mining operations, armed forces and local heating suppliers. Currently gas for these uses is imported from Uzbekistan.

Scott Pickford has evaluated the economics of the 10 prospects and leads that have been described in Section 2. Each prospect has been evaluated assuming developments based on both Natural Depletion and Water Injection scenarios, using well initials of 300, 1,000 and 2,000bbls/day respectively. For gas initial well rates of 2 and 5MMcfd were considered.

For evaluation purposes it has been assumed that each prospect will have an exploration cost consisting of US$ 1 million seismic plus an exploration well, the cost of which will vary, with depth, in the range US$ 1 to 5 million.

The major cost to develop each prospect is drilling and we have used as a guide, throughout the evaluation, "Kyrgyzneftegas" well cost data supplied to us by DWM. This data, supplied in 2005, has been updated to mid 2006 values by increasing the imported materials costs (casing and completions) by 50% and keeping all other costs the same in US$ terms.

In those cases with deep wells and low initials, a major development constraint will be the ability to drill sufficient wells fast enough to maintain an adequate production profile. For practical purposes it has been assumed that the optimum number of rigs that can be deployed in any field is four, (except at Burdalyk where due to its relatively large size 6 has been assumed).

4.2. Capital Costs

4.2.1. Exploration

4.2.1.1. Seismic

DWM intend to carry out a seismic acquisition programme with a budget estimated at US$ 5 million. This seismic acquisition programme will concentrate on the 5 high-graded prospects as based on the current dataset. It has been assumed for the purposes of this evaluation that the seismic will be shot and processed during 2007, enabling an exploration well programme to commence during 2008.

4.2.1.2. Exploration drilling

The capital cost of exploration wells is assumed to be the same as a production well (see Table 5 below) plus an allowance for coring, testing etc. This assumption results in exploration wells costing between US$ 1 million for the shallow prospects to US$ 5 million for the deeper prospects.

Drilling Costs

	(in US$)			
Operation	**Wells**			
	Ultra Deep	**Deep**	**Average**	**Shallow**
Drilling/m	260	220	180	100
Casing/m	45	45	45	45
Cementing/well	7000	5000	3000	2000
Perforation/well	7000	5000	3000	2750
Logging/well	12500	10000	7200	5200
Compln&testing/well	12500	10000	7200	5000
Pads/Roads	5500	5000	4500	4000
Geological/Transport	3000	2500	2500	2000
General				
Drilling/Casing/m	300	250	230	145
Fixed Costs	50000	37200	27150	20300
Completion/well	150000	150000	150000	150000

Table 5 – Components of drilling costs for wells in Kyrgyzstan

4.2.2. Development Costs

4.2.2.1 Wells

The number of production wells required to develop each field has been calculated from the estimated recoverable reserves for each prospect divided by the estimated quantity of oil that each well can drain under the different development scenarios.

For Water Injection cases this figure has had one water injection well added for every four production wells. In our calculations we have assumed that water injection will be implemented at or near field start-up. It may prove possible later in field life to re-complete certain production wells as injectors thus reducing the number of wells required for drilling, however this refinement has not been incorporated in our value determinations at this stage.

The estimated length of time required to drill each well varies from approximately 120 days for the deep wells (5,500m) to approximately 7 days for the shallow wells (300m). For the deep prospects this results in very large numbers of wells required to develop each field. For practical purposes it has been assumed that in general 4 rigs will be available to drill up each field although additional 2 rigs could be mobilised if required. This restriction in the number of available rigs has meant that in those cases where low initial well production rates have been assumed it would take several years to drill the necessary number of wells on many of the structurally deep fields. The drilling costs for each field development were calculated using the costs shown in Table 5.

4.2.3. Production Facilities

In comparison to the drilling costs the production facilities costs will be relatively inexpensive.

It has been assumed that each field development will require separation facilities, metering facilities and storage and railcar loading facilities. For the Water Injection cases, water injection facilities will also be required. Additionally, a control room, a maintenance workshop and accommodation for staff will also be required. A nominal US$ 4.5 million has been included for each development scenario to cover production facilities.

For gas development scenarios it has been assumed that each discovery will require separation, dehydration, compression and metering facilities. The total facilities cost for gas export cases has been taken as US$7.5 million and includes control room, maintenance workshop and staff accommodation costs.

4.2.4. Gas Pipelines

A 7km pipeline required to deliver gas from the Tuzluk area prospects to the gas compression station on the Gazly-Ferghana pipeline is estimated to cost $0.5MM. In the other licence areas existing pipelines are present and only short minimal cost tie-ins would be required.

4.3. Operating Costs

4.3.1. Well Costs

An annual allowance of 10% of the capital cost of each operating well has been allowed for well operating costs.

4.3.2. Facilities Costs

An annual allowance of 10% of the capital cost of the facilities has been included for facilities operating cost.

4.3.3. Transport

The transportation cost to transport crude oil to the refinery has been included as US$ 2/bbl transported. This figure was supplied by DWM. If oil is exported the estimated transport cost would rise to $ 9/bbl. No transport cost has been allowed for in gas export cases.

4.4. Taxation

4.4.1. Excise Duty

Excise Duty has been assumed to be levied at a rate of US$14 / metric tonne on all oil sold to the domestic market. It has been assumed that no excise duty will be levied on oil or gas exports.

4.4.2. Royalty

Royalty has been assumed to be levied at a rate of 3% of the realised price of both oil and gas sales.

4.4.3. Taxes (Other)

An additional local tax has been assumed calculated at a rate of 3% of the realised price of both oil and gas sales.

4.4.4. Income Tax

Income taxes have been assumed to be levied at a rate of 20% of the income from the oil production after the deduction of Excise Duty, Royalty, other Taxes, Operating Costs and depreciation calculated at a rate of 25% straight line.

4.5. Oil Price

The base oil price has been assumed to be US$35/bbl delivered to the refinery, or exported after incurring equivalent costs. Sensitivities have been calculated at US$40 and US$45/bbl.

4.6. Gas Price

An example contract price known to Scott Pickford is that paid by the Mailisai light bulb factory. This price ranges between US$ 52-64 per thousand cubic metres (equivalent to $1.47 – 1.81 /Mcf). As a result of this a base price of $1.75 /Mcf has been used with an upside sensitivity of $2.10.

4.7. Economic Values

The economic value of each development scenario has been evaluated (in mid 2006 million US$). Due to the large number of cases analysed only the values (using a 10% discount rate and $35 oil price) of the most likely technical case for those prospects considered to be the likely choice for the first drilling campaign are shown in Appendix C. The resources quoted in Appendix C have been truncated to reflect economic cut-offs and hence may be less than the ultimate technically recoverable volumes. In all cases it has been assumed that the produced oil will be sold to the domestic market. Should the volumes produced exceed the local demand or capacity then the oil may be exported. However, export will incur higher transports costs of $ 9/bbl as compared to $2 /bbl for domestic this will be partly offset by the removal of excise duty currently at $2 /bbl.

The Estimated Monetary Value (EMV) of each prospect has been evaluated using the formula shown below:

EMV = (NPV *CoS) – ((Cost of dry well * (1-CoS))

where, “NPV” = Net Present Value & “CoS” = Chance of Success

The resultant EMVs are shown in Tables 6 and 7 clearly show that the shallower prospects are very attractive and that the deeper prospects become attractive when higher initial well productivities are assumed (1,000bbls/d and higher).

EMV_{10} (US $MM)

		Natural Depletion		
Licence Area	**Prospect**	**300 bbl/day**	**1000 bbl/day**	**2000 bbl/day**
Nanai	**Alabuka 1**	19.15	37.69	48.22
	Alabuka 2	0.8	12.53	19.29
	Alabuka 3	5.75	7.13	10.02
Soh	**Burdalyk**	93.56	181.88	209.47
	Kyzyl-Kurgan	18.80	61.68	78.78
	West Chaur	145.17	144.86	194.39
Tuzluk	**South Tuzluk**	36.75	63.12	67.88
	West Tuzluk	4.56	11.69	15.50
	Tashravat	63.50	71.99	79.65
	West Beshkent	27.50	30.35	42.36

Table 6 – Summary of the EMV_{10} for the natural depletion scenario developments for the key prospects and leads

EMV_{10} (US $MM)

		Water Injection		
Licence Area	**Prospect**	**300 bbl/day**	**1000 bbl/day**	**2000 bbl/day**
Nanai	**Alabuka 1**	10.77	44.71	53.77
	Alabuka 2	-0.78	16.51	22.09
	Alabuka 3	7.13	14.13	15.50
Soh	**Burdalyk**	105.80	200.35	232.03
	Kyzyl-Kurgan	22.39	75.14	87.02
	West Chaur	172.71	168.51	178.51
Tuzluk	**South Tuzluk**	48.28	73.61	83.79
	West Tuzluk	6.63	13.47	17.79
	Tashravat	74.53	88.44	118.03
	West Beshkent	45.58	41.43	56.92

Table 7 – Summary of the EMV_{10} for the water injection scenario developments for the key prospects and leads

The total EMV for the above prospects ranges from $415.54MM (300 bbls/day well initials – natural depletion scenario) to $864.45MM (2,000 bbls/day well initials - water injection scenario). The most likely value outcome is considered to be the 300 bbls/day well initials scenario for the shallow fields (West Chaur and Tashravat) and the 1000 bbls/day well initials scenario for the deeper fields, both assuming water injection, giving an EMV of $726.59MM.

The EMVs for the gas development cases are currently all negative. However they may become positive after the acquisition and interpretation of further seismic data which it is predicted will increase the chance of success attached to each prospect. Once the decision has been made to go ahead with an oil field development the gas resources will be produced concurrently both to satisfy local demands and provide power for field operations. An example cashflow for the Burdalyk prospect gas case is shown in Appendix C. This case shows a small positive NPV but a negative EMV. It may prove possible to re-negotiate the gas price received and hence improve the value.

4.7.1. Value Sensitivity to Oil Price

The following table shows the sensitivity of the EMV_{10} to oil price for the most likely development scenario i.e. water injection with initial flowrates of 300bbls/d for the shallow prospects (West Chaur and Tashravat) and 1,000bbls/d for the deeper prospects.

EMV_{10} (US $MM)

		Oil Price (US $)		
Licence Area	**Prospect**	**35**	**40**	**45**
Nanai	**Alabuka 1**	44.71	55.29	65.88
	Alabuka 2	16.51	21.19	25.88
	Alabuka 3	14.13	17.52	20.92
Soh	**Burdalyk**	200.35	239.51	278.67
	Kyzyl-Kurgan	75.14	91.51	107.88
	West Chaur	172.71	204.15	235.58
Tuzluk	**South Tuzluk**	73.61	88.14	102.68
	West Tuzluk	13.47	16.82	20.17
	Tashravat	74.53	89.41	104.28
	West Beshkent	41.43	49.01	56.99

Table 8 – Sensitivity of EMV_{10} to oil price for the most likely development cases

5. Professional Qualifications and Basis of Opinion

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The evaluation has been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, Scott Pickford is not in a position to attest to the property title, financial interest relationships or encumbrances related to the property. Our estimates of potential resources, unrisked and risked values are based on data provided by DWM. We have accepted, without independent verification, the accuracy and completeness of these data.

The report represents our best professional judgement and should not be considered a guarantee or prediction of results. It should be understood that any evaluation of reserve volumes and corresponding NPVs of petroleum developments, may be subject to significant variations over short periods of time as new information become available and perceptions change.

Scott Pickford Ltd is a consultancy specialising in geology, geophysics, petrophysics, petroleum engineering and economic analyses. Scott Pickford Ltd began undertaking reserves reporting and valuation functions in 1986 and all its personnel involved in such exercises have at the very minimum a first degree in geoscience or petroleum engineering and many have masters degrees or doctorates. All personnel have a minimum of five years relevant valuation experience and in the case of the senior project leaders involved in this exercise this period exceeds ten years. Except for the provision of professional services on a fee basis, Scott Pickford Ltd and its employees has no commercial arrangement with any person or company involved in the interests that are the subject of this report.

Yours faithfully,

Andrew J. Kirchin, BSc (Geophysics with Geology, University of Liverpool), Member of the Petroleum Exploration Society of Great Britain (PESGB) and European Association of Geoscientists and Engineers (EAGE).

Managing Director

Scott Pickford Ltd

4th Floor, Leon House
233 High Street
Croydon
Surrey
CR0 9XT, UK

Appendix A – Definitions

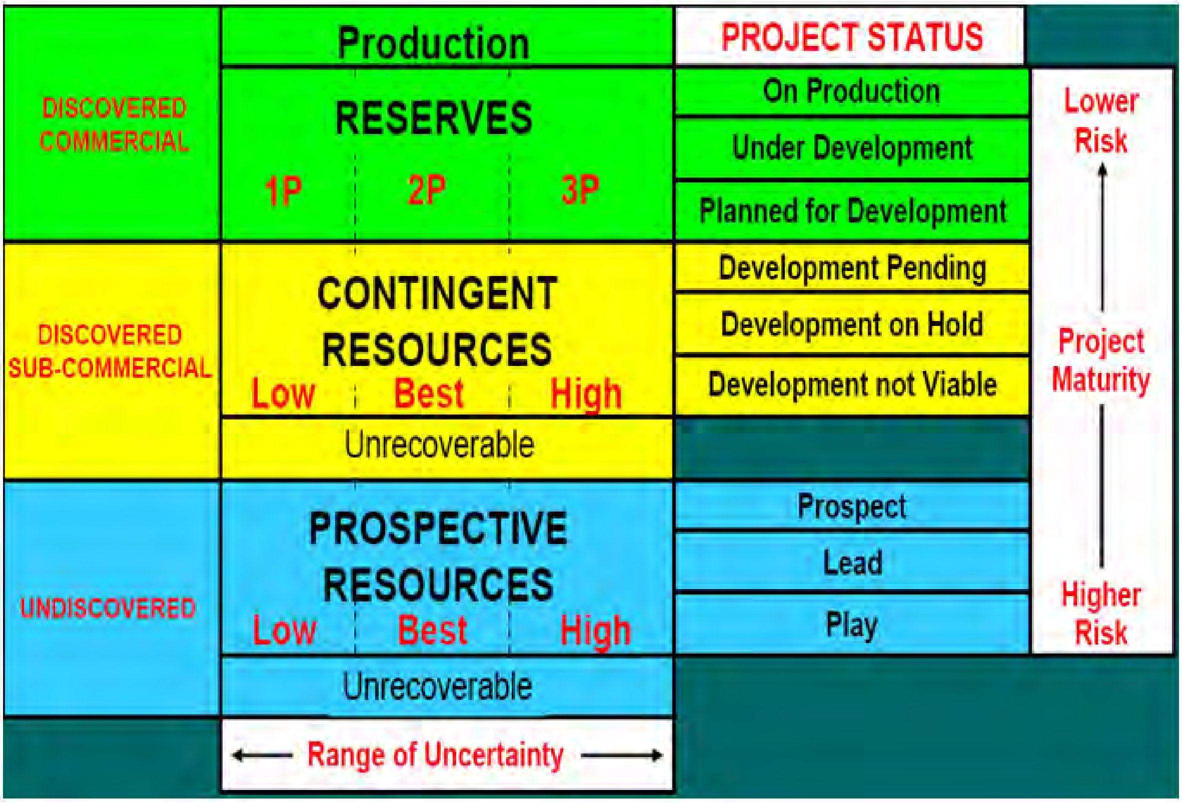
Definitions used in this report are as follows.

"/d, pd, PD"	means per day
"°API"	means American Petroleum Institute units of specific gravity of liquid hydrocarbon
"bbl"	means barrel(s)
"bopd"	means barrels of oil produced per day
"DHI"	means direct hydrocarbon indicator
"DSDP"	Deep Sea Drilling Project
"FPSO"	means Floating Production, Storage and Offtake vessel
"FWHP"	means flowing wellhead pressure
"GOC"	means gas-oil-contact
"GOR"	means gas:oil ratio
"GRV"	means gross rock volume
"GWC"	means gas-water-contact
"Hydrocarbon"	means oil and/or gas and/or condensate
"Kr"	means relative permeability
"Lead"	means a structure that requires further technical appraisal prior to a decision to drill or not
"M", "MM", "B"	means thousands, millions, billions (thousand million) respectively
"mybp"	means millions of years before present
"NRI"	means Net Revenue Interest
"NPV"	means Net Present Value and is the total present value of a series of cash flows discounted at a specified rate, to a specified date.
"ODT"	means oil-down-to
"OWC"	means oil-water-contact
"P10"	means 10% probability that value will be equal to or greater than stated value. Note that where indicative STOIIP and reserve volumes are mentioned these are probabilities of volume size *if any hydrocarbons are encountered*
"P50"	means 50% probability that value will be equal to or greater than stated value. Note that where indicative STOIIP and reserve volumes are mentioned these are probabilities of volume size *if any hydrocarbons are encountered*
"P90"	means 90% probability that value will be equal to or greater than stated value. Note that where indicative STOIIP and reserve volumes are mentioned these are probabilities of volume size *if any hydrocarbons are encountered*
"PPL"	Petroleum Production Licence
"Prospect"	means a structure that has been technically evaluated to a state where it is ready to be drilled
"PSC"	Production Sharing Contracts
"PTD"	Means Proposed Total Depth
"PVT"	means pressure - volume - temperature
"RCI"	Formation Pressure Testing Tool (Baker Atlas)
"Reserves"	means potential volume of hydrocarbon that could be commercially produced from a field. Note that all reserves presented in this report are conceptual. Formal reserves cannot be attributed to the prospects at this stage of exploration since the existence of commercially developable hydrocarbon accumulations is conceptual. In all of the prospects there is uncertainty about reservoir presence and quality, hydrocarbon presence and, on the assumption that hydrocarbons are found, their type and the potential well deliverability
"Resources"	means those volumes of hydrocarbons either yet to be found (prospective) or if found the development of which depends upon a number of factors being resolved (contingent)
"RMS"	means root mean squared
"Sw"	means water saturation (compliment of hydrocarbon saturation
"s", "scf", "SCF"	means standard cubic feet (of gas)
"SPE"	means Society of Petroleum Engineers
"stb", "STB"	means stock tank barrel(s) measured at 14.7 psia and 60° Fahrenheit
"STOIIP"	means stock tank volume of oil initially-in-place, i.e. prior to production
"TOC"	means total organic carbon
"tvdss"	means true vertical depth sub sea
"Vsh"	means volume of shale

"WI" "WPC"	means Working Interest means World Petroleum Congress

Reserve and Resource Definitions

The diagram below illustrates the different reserve and resource categories as defined by the SPE and adhered to in this report.



Given below are brief definitions of the main reserve and resource categories, fuller definitions can be found on the Society of Petroleum Engineers (SPE) website (www.spe.org)

Proved Reserves

Based on the available evidence and taking into account technical and economic factors these reserves will have a better than 90 percent chance of being produced.

Probable Reserves

Based on the available evidence and taking into account technical and economic factors these reserves will have a better than 50 percent chance of being produced.

Possible Reserves

Based on the available evidence and taking into account technical and economic factors these reserves will have a better than 10 percent chance of being produced.

Contingent Resources

Volumes of hydrocarbon that are potentially recoverable from a known accumulation subject to the formulation of an economic development scheme.

Prospective Resources

The potential volume of hydrocarbon that could be commercially produced from an as yet undiscovered field.

The estimation of 'Chance of Success' is generally determined by Scott Pickford in the following manner.

The 'Chance of Success' incorporates the following key risks:

- TRAP (Structure and Seal): The expectation of there being an adequate hydrocarbon trapping mechanism and the trap is effectively sealed.
- RESERVOIR: The expectation of effective reservoir rocks being present.
- CHARGE (Source and Migration): The expectation of there having been a source of sufficient hydrocarbon generated in the system and that this generated hydrocarbon could have migrated into the trap.

The risks incorporate both the presence and effectiveness of these critical factors. Since these three key factors are independent and all three must be present for a successful outcome, the overall 'Chance of Success' is calculated as the product of the three probabilities. If the three key factors described above are each judged to have a 50per cent expectation then the 'Chance of Success' for the prospect is 12.5 per cent being the product of these independent probabilities.

Appendix B – Production Profiles

Base Case 300bopd

Year	Average well rate (bbl/d)	Annual Production per well (Mbbls)	Cumulative Production per well (MMbbls)
1	300	109.58	0.11
2	240	87.66	0.20
3	192	70.13	0.27
4	154	56.10	0.32
5	123	44.88	0.37
6	98	35.91	0.40
7	79	28.72	0.43
8	63	22.98	0.46
9	50	18.38	0.47
10	40	14.71	0.49
11	32	11.77	0.50
12	26	9.41	0.51
13	21	7.53	0.52
14	16	6.02	0.52
15	13	4.82	0.53

1000bopd Case

Year	Average well rate (bbl/d)	Annual Production per well (Mbbls)	Cumulative Production per well (MMbbls)
1	1000	365.25	0.37
2	800	292.20	0.66
3	640	233.76	0.89
4	512	187.01	1.08
5	410	149.61	1.23
6	328	119.69	1.35
7	262	95.75	1.44
8	210	76.60	1.52
9	168	61.28	1.58
10	134	49.02	1.63
11	107	39.22	1.67
12	86	31.37	1.70
13	69	25.10	1.73
14	55	20.08	1.75
15	44	16.06	1.76

2000bopd Case

Year	Average well rate (bbl/d)	Annual Production per well (Mbbls)	Cumulative Production per well (MMbbls)
1	2000	730.50	0.73
2	1600	584.40	1.31
3	1280	467.52	1.78

4	1024	374.02	2.16
5	819	299.21	2.46
6	655	239.37	2.70
7	524	191.50	2.89
8	419	153.20	3.04
9	336	122.56	3.16
10	268	98.05	3.26
11	215	78.44	3.34
12	172	62.75	3.40
13	137	50.20	3.45
14	110	40.16	3.49
15	88	32.13	3.52

Gas Base Case (2 MMcfd)

Year	Average well rate (MMcfd)	Annual Production per well (Bcf)	Cumulative Production per well (Bcf)
1	2.00	0.73	0.73
2	1.60	0.58	1.31
3	1.28	0.47	1.78
4	1.02	0.37	2.16
5	0.82	0.30	2.46
6	0.66	0.24	2.70
7	0.52	0.19	2.89
8	0.42	0.15	3.04
9	0.34	0.12	3.16
10	0.27	0.10	3.26
11	0.21	0.08	3.34
12	0.17	0.06	3.40
13	0.14	0.05	3.45
14	0.11	0.04	3.49
15	0.09	0.03	3.52

Gas Base Case (5 MMcfd)

Year	Average well rate (MMcfd)	Annual Production per well (Bcf)	Cumulative Production per well (Bcf)
1	5.00	1.83	1.83
2	4.00	1.46	3.29
3	3.20	1.17	4.46
4	2.56	0.94	5.39
5	2.05	0.75	6.14
6	1.64	0.60	6.74
7	1.31	0.48	7.22
8	1.05	0.38	7.60
9	0.84	0.31	7.91
10	0.67	0.25	8.15
11	0.54	0.20	8.35
12	0.43	0.16	8.50
13	0.34	0.13	8.63
14	0.27	0.10	8.73
15	0.22	0.08	8.81

Appendix C – Cashflows and Economic Values

Alabuka 1 Water Injection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						5.00			-5.00	-4.50
2009	2.19	76.70	4.15	2.30	2.30	58.13	10.55	0.00	-0.72	-0.65
2010	4.46	155.96	8.43	4.68	4.68	17.88	16.99	8.27	95.04	85.53
2011	4.41	154.30	8.34	4.63	4.63	0.00	16.89	40.27	79.53	71.58
2012	3.75	131.15	7.09	3.93	3.93	0.00	15.57	39.72	60.90	54.81
2013	3.19	111.48	6.03	3.34	3.34	0.00	14.45	32.05	52.27	47.04
2014	2.71	94.76	5.12	2.84	2.84	0.00	13.49	31.94	38.52	34.67
2015	2.30	80.55	4.35	2.42	2.42	0.00	12.68	14.09	44.59	40.13
2016	1.96	68.46	3.70	2.05	2.05	0.00	11.99	23.47	25.19	22.67
2017	1.66	58.19	3.15	1.75	1.75	0.00	11.40	19.47	20.69	18.62
2018	1.41	49.47	2.67	1.48	1.48	0.00	10.90	16.06	16.86	15.17
2019	1.20	42.05	2.27	1.26	1.26	0.00	10.48	13.17	13.60	12.24
2020	1.02	35.74	1.93	1.07	1.07	0.00	10.12	10.71	10.84	9.75
2021	0.87	30.38	1.64	0.91	0.91	0.00	9.81	8.62	8.48	7.63
2022	0.74	25.82	1.40	0.77	0.77	0.00	9.55	6.84	6.48	5.84
2023	0.63	21.95	1.19	0.66	0.66	0.00	9.33	5.33	4.78	4.31
2024	0.53	18.66	1.01	0.56	0.56	0.00	9.14	4.05	3.34	3.01
2025	0.45	15.86	0.86	0.48	0.48	0.00	8.98	2.95	2.11	1.90
2026	0.39	13.48	0.73	0.40	0.40	0.00	8.85	2.03	1.07	0.96
2027	0.33	11.46	0.62	0.34	0.34	0.00	8.73	1.24	0.18	0.16
Totals	**34.18**	**1196.41**	**64.67**	**35.89**	**35.89**	**82.00**	**219.92**	**280.28**	**477.75**	**429.98**

	Post Tax Cash Flow	Company Share
NPV@10%	**265.58**	**239.02**
NPV@15%	**207.28**	**186.55**
COS%	**20.50**	**20.50**
EMV	**49.67**	**44.71**

RF 0.32

Oil Price Sensitivity	**US$**	**35**	**40**	**45**
NPV@10%		**239.02**	**315.22**	**366.87**
EMV		**44.71**	**55.29**	**65.88**

Alabuka 2 Water Injection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						5.00			-5.00	-4.50
2009	2.01	70.31	3.80	2.11	2.11	56.63	9.56	0.00	-3.89	-3.51
2010	3.42	119.53	6.46	3.59	3.59	0.00	12.37	7.41	86.11	77.50
2011	2.90	101.60	5.49	3.05	3.05	0.00	11.35	31.15	47.52	42.76
2012	2.47	86.36	4.67	2.59	2.59	0.00	10.48	25.20	40.83	36.75
2013	2.10	73.41	3.97	2.20	2.20	0.00	9.74	20.15	35.14	31.63
2014	1.78	62.39	3.37	1.87	1.87	0.00	9.11	22.12	24.05	21.65
2015	1.52	53.04	2.87	1.59	1.59	0.00	8.57	9.23	29.18	26.26
2016	1.29	45.08	2.44	1.35	1.35	0.00	8.12	15.36	16.45	14.81
2017	1.09	38.32	2.07	1.15	1.15	0.00	7.73	12.73	13.49	12.14
2018	0.93	32.57	1.76	0.98	0.98	0.00	7.40	10.49	10.97	9.87
2019	0.79	27.68	1.50	0.83	0.83	0.00	7.13	8.58	8.82	7.94
2020	0.67	23.53	1.27	0.71	0.71	0.00	6.89	6.96	7.00	6.30
2021	0.57	20.00	1.08	0.60	0.60	0.00	6.69	5.58	5.45	4.91
2022	0.49	17.00	0.92	0.51	0.51	0.00	6.51	4.41	4.13	3.72
2023	0.41	14.45	0.78	0.43	0.43	0.00	6.37	3.42	3.02	2.71
2024	0.35	12.28	0.66	0.37	0.37	0.00	6.25	2.57	2.06	1.86
2025	0.30	10.44	0.56	0.31	0.31	0.00	6.14	1.86	1.26	1.13
2026	0.25	8.88	0.48	0.27	0.27	0.00	6.05	1.24	0.57	0.51
2027	0.22	7.54	0.41	0.23	0.23	0.00	5.97	0.72	-0.02	-0.01
Totals	**23.55**	**824.42**	**44.57**	**24.73**	**24.73**	**62.63**	**152.43**	**189.20**	**326.13**	**293.52**
							NPV@10%		**184.19**	**165.77**
							NPV@15%		**144.65**	**130.19**
							COS%		**12.80**	**12.80**
							EMV		**18.34**	**16.51**

RF	0.32	**Oil Price Sensitivity**	**US$**	**35**	**40**	**45**
		NPV@10%		**165.77**	**219.83**	**256.42**
		EMV		**16.51**	**21.19**	**25.88**

Alabuka 3 Water Injection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						3.00			-3.00	-2.70
2009	1.83	63.92	3.46	1.92	1.92	32.10	6.93	0.00	17.60	15.84
2010	3.10	108.66	5.87	3.26	3.26	0.00	9.49	8.13	78.64	70.78
2011	2.64	92.36	4.99	2.77	2.77	0.00	8.56	31.10	42.17	37.95
2012	2.24	78.51	4.24	2.36	2.36	0.00	7.77	25.70	36.09	32.48
2013	1.91	66.73	3.61	2.00	2.00	0.00	7.09	21.10	30.92	27.83
2014	1.62	56.72	3.07	1.70	1.70	0.00	6.52	20.81	22.92	20.63
2015	1.38	48.21	2.61	1.45	1.45	0.00	6.04	8.75	27.93	25.14
2016	1.17	40.98	2.22	1.23	1.23	0.00	5.62	14.67	16.01	14.41
2017	1.00	34.83	1.88	1.05	1.05	0.00	5.27	12.27	13.32	11.98
2018	0.85	29.61	1.60	0.89	0.89	0.00	4.97	10.24	11.02	9.92
2019	0.72	25.17	1.36	0.76	0.76	0.00	4.72	8.50	9.07	8.17
2020	0.61	21.39	1.16	0.64	0.64	0.00	4.50	7.03	7.42	6.68
2021	0.52	18.18	0.98	0.55	0.55	0.00	4.32	5.78	6.01	5.41
2022	0.44	15.46	0.84	0.46	0.46	0.00	4.16	4.72	4.81	4.33
2023	0.38	13.14	0.71	0.39	0.39	0.00	4.03	3.81	3.80	3.42
2024	0.32	11.17	0.60	0.34	0.34	0.00	3.92	3.04	2.93	2.64
2025	0.27	9.49	0.51	0.28	0.28	0.00	3.82	2.39	2.20	1.98
2026	0.23	8.07	0.44	0.24	0.24	0.00	3.74	1.83	1.57	1.41
2027	0.20	6.86	0.37	0.21	0.21	0.00	3.67	1.36	1.04	0.94
Totals	**21.41**	**749.47**	**40.51**	**22.48**	**22.48**	**36.10**	**105.16**	**191.25**	**331.48**	**298.33**

	Post Tax Cash Flow	Company Share
NPV@10%	**189.14**	**170.22**
NPV@15%	**150.16**	**135.14**
COS%	**10.20**	**10.20**
EMV	**15.70**	**14.13**

RF 0.33

Oil Price Sensitivity	**US$**	**35**	**40**	**45**
NPV@10%		**170.22**	**210.41**	**243.68**
EMV		**14.13**	**17.52**	**20.92**

Burdalyk Post Water Injection Case Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						3.00			-3.00	-2.70
2009	3.29	115.05	6.22	3.45	3.45	58.90	12.70	0.00	30.34	27.30
2010	8.88	310.65	16.79	9.32	9.32	54.40	29.55	14.70	176.56	158.91
2011	13.63	476.90	25.78	14.31	14.31	52.03	44.73	86.54	239.21	215.29
2012	15.08	527.81	28.53	15.83	15.83	18.92	49.53	134.18	264.98	238.49
2013	13.42	469.60	25.38	14.09	14.09	0.00	46.20	148.41	221.42	199.28
2014	11.40	399.16	21.58	11.97	11.97	0.00	42.18	135.40	176.05	158.45
2015	9.69	339.28	18.34	10.18	10.18	0.00	38.76	58.74	203.09	182.78
2016	8.24	288.39	15.59	8.65	8.65	0.00	35.85	102.84	116.81	105.13
2017	7.00	245.13	13.25	7.35	7.35	0.00	33.38	87.86	95.94	86.34
2018	5.95	208.36	11.26	6.25	6.25	0.00	31.28	73.52	79.80	71.82
2019	5.06	177.11	9.57	5.31	5.31	0.00	29.49	61.33	66.09	59.48
2020	4.30	150.54	8.14	4.52	4.52	0.00	27.97	50.97	54.43	48.99
2021	3.66	127.96	6.92	3.84	3.84	0.00	26.68	42.16	44.52	40.07
2022	3.11	108.77	5.88	3.26	3.26	0.00	25.59	34.67	36.10	32.49
2023	2.64	92.45	5.00	2.77	2.77	0.00	24.65	28.31	28.94	26.05
2024	2.25	78.58	4.25	2.36	2.36	0.00	23.86	22.90	22.86	20.57
2025	1.91	66.80	3.61	2.00	2.00	0.00	23.19	18.30	17.69	15.92
2026	1.62	56.78	3.07	1.70	1.70	0.00	22.61	14.40	13.29	11.96
2027	1.38	48.26	2.61	1.45	1.45	0.00	22.13	11.07	9.55	8.60
Totals	**122.50**	**4287.58**	**231.77**	**128.63**	**128.63**	**188.24**	**590.33**	**1126.30**	**1893.69**	**1704.32**
							NPV@10%		**981.27**	**883.15**
							NPV@15%		**746.40**	**671.76**
							COS%		**23.00**	**23.00**
							EMV		**222.61**	**200.35**

RF	0.31	**Oil Price Sensitivity**	**US$**	**35**	**40**	**45**
		NPV@10%		**883.15**	**1053.40**	**1223.65**
		EMV		**200.35**	**239.51**	**278.67**

Kyzyl-Kurgan Water Injection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						5.00			-5.00	-4.50
2009	2.19	76.70	4.15	2.30	2.30	53.59	10.07	0.00	4.30	3.87
2010	5.67	198.57	10.73	5.96	5.96	42.54	20.96	8.60	103.83	93.44
2011	6.48	226.74	12.26	6.80	6.80	0.00	22.57	51.77	126.54	113.88
2012	5.51	192.73	10.42	5.78	5.78	0.00	20.63	61.11	89.01	80.11
2013	4.68	163.82	8.86	4.91	4.91	0.00	18.97	49.84	76.33	68.69
2014	3.98	139.25	7.53	4.18	4.18	0.00	17.57	46.21	59.58	53.63
2015	3.38	118.36	6.40	3.55	3.55	0.00	16.38	21.16	67.33	60.59
2016	2.87	100.61	5.44	3.02	3.02	0.00	15.36	35.39	38.38	34.54
2017	2.44	85.52	4.62	2.57	2.57	0.00	14.50	29.51	31.75	28.58
2018	2.08	72.69	3.93	2.18	2.18	0.00	13.77	24.50	26.13	23.51
2019	1.77	61.78	3.34	1.85	1.85	0.00	13.14	20.25	21.34	19.21
2020	1.50	52.52	2.84	1.58	1.58	0.00	12.61	16.64	17.28	15.55
2021	1.28	44.64	2.41	1.34	1.34	0.00	12.16	13.57	13.82	12.44
2022	1.08	37.94	2.05	1.14	1.14	0.00	11.78	10.95	10.88	9.79
2023	0.92	32.25	1.74	0.97	0.97	0.00	11.46	8.73	8.38	7.55
2024	0.78	27.41	1.48	0.82	0.82	0.00	11.18	6.85	6.26	5.63
2025	0.67	23.30	1.26	0.70	0.70	0.00	10.94	5.24	4.46	4.01
2026	0.57	19.81	1.07	0.59	0.59	0.00	10.74	3.88	2.92	2.63
2027	0.48	16.84	0.91	0.51	0.51	0.00	10.58	2.72	1.62	1.46
Totals	**48.33**	**1691.48**	**91.44**	**50.74**	**50.74**	**102.13**	**275.38**	**416.93**	**704.12**	**633.71**

	Post Tax Cash Flow	Company Share
NPV@10%	**383.08**	**344.77**
NPV@15%	**296.78**	**267.10**
COS%	**23.00**	**23.00**
EMV	**83.49**	**75.14**

RF 0.32

Oil Price Sensitivity	**US$**	**35**	**40**	**45**
NPV@10%		**344.77**	**415.95**	**487.12**
EMV		**75.14**	**91.51**	**107.88**

West Chaur Water Injection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						1.00			-1.00	-0.90
2009	3.47	121.45	6.56	3.64	3.64	14.80	8.48	0.00	84.32	75.89
2010	5.90	206.46	11.16	6.19	6.19	0.00	13.33	18.98	150.59	135.53
2011	5.01	175.49	9.49	5.26	5.26	0.00	11.56	66.15	77.76	69.98
2012	4.26	149.17	8.06	4.47	4.47	0.00	10.06	55.88	66.21	59.59
2013	3.62	126.79	6.85	3.80	3.80	0.00	8.78	47.16	56.39	50.75
2014	3.08	107.77	5.83	3.23	3.23	0.00	7.70	41.42	46.37	41.73
2015	2.62	91.61	4.95	2.75	2.75	0.00	6.77	17.56	56.83	51.15
2016	2.22	77.87	4.21	2.34	2.34	0.00	5.99	29.75	33.24	29.92
2017	1.89	66.19	3.58	1.99	1.99	0.00	5.32	25.20	28.12	25.31
2018	1.61	56.26	3.04	1.69	1.69	0.00	4.75	21.33	23.76	21.39
2019	1.37	47.82	2.58	1.43	1.43	0.00	4.27	18.04	20.06	18.05
2020	1.16	40.65	2.20	1.22	1.22	0.00	3.86	15.24	16.91	15.22
2021	0.99	34.55	1.87	1.04	1.04	0.00	3.51	12.86	14.24	12.81
2022	0.84	29.37	1.59	0.88	0.88	0.00	3.21	10.84	11.96	10.77
2023	0.71	24.96	1.35	0.75	0.75	0.00	2.96	9.12	10.03	9.03
2024	0.61	21.22	1.15	0.64	0.64	0.00	2.75	7.66	8.39	7.55
2025	0.52	18.03	0.97	0.54	0.54	0.00	2.57	6.42	6.99	6.29
2026	0.44	15.33	0.83	0.46	0.46	0.00	2.41	5.36	5.80	5.22
2027	0.37	13.03	0.70	0.39	0.39	0.00	2.28	4.47	4.80	4.32
Totals	**40.69**	**1423.99**	**76.98**	**42.72**	**42.72**	**16.80**	**110.57**	**413.44**	**720.77**	**648.69**
							NPV@10%		**376.46**	**338.82**
							NPV@15%		**288.80**	**259.92**
							COS%		**50.00**	**50.00**
							EMV		**187.23**	**168.51**

RF	0.32	**Oil Price Sensitivity**	**US$**	**35**	**40**	**45**
		NPV@10%		**338.82**	**396.28**	**453.74**

South Tuzluk Water Injection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						3.00			-3.00	-2.70
2009	3.47	121.45	6.56	3.64	3.64	54.00	12.61	0.00	40.98	36.88
2010	5.90	206.46	11.16	6.19	6.19	0.00	17.47	16.10	149.34	134.41
2011	5.01	175.49	9.49	5.26	5.26	0.00	15.70	60.37	79.40	71.46
2012	4.26	149.17	8.06	4.47	4.47	0.00	14.20	50.11	67.85	61.06
2013	3.62	126.79	6.85	3.80	3.80	0.00	12.92	41.38	58.03	52.23
2014	3.08	107.77	5.83	3.23	3.23	0.00	11.83	39.76	43.88	39.49
2015	2.62	91.61	4.95	2.75	2.75	0.00	10.91	16.73	53.52	48.17
2016	2.22	77.87	4.21	2.34	2.34	0.00	10.12	28.10	30.76	27.68
2017	1.89	66.19	3.58	1.99	1.99	0.00	9.46	23.54	25.64	23.07
2018	1.61	56.26	3.04	1.69	1.69	0.00	8.89	19.67	21.28	19.15
2019	1.37	47.82	2.58	1.43	1.43	0.00	8.41	16.38	17.58	15.82
2020	1.16	40.65	2.20	1.22	1.22	0.00	8.00	13.58	14.43	12.99
2021	0.99	34.55	1.87	1.04	1.04	0.00	7.65	11.21	11.75	10.58
2022	0.84	29.37	1.59	0.88	0.88	0.00	7.35	9.18	9.48	8.53
2023	0.71	24.96	1.35	0.75	0.75	0.00	7.10	7.47	7.55	6.79
2024	0.61	21.22	1.15	0.64	0.64	0.00	6.89	6.01	5.90	5.31
2025	0.52	18.03	0.97	0.54	0.54	0.00	6.71	4.76	4.51	4.06
2026	0.44	15.33	0.83	0.46	0.46	0.00	6.55	3.71	3.32	2.99
2027	0.37	13.03	0.70	0.39	0.39	0.00	6.42	2.81	2.31	2.08
Totals	**40.69**	**1423.99**	**76.98**	**42.72**	**42.72**	**58.00**	**189.20**	**370.88**	**643.50**	**579.15**
							NPV@10%		**368.98**	**332.08**
							NPV@15%		**293.98**	**264.58**
							COS%		**23.00**	**23.00**
							EMV		**81.79**	**73.61**

RF 0.32

Oil Price Sensitivity	US$	35	40	45
NPV@10%		**332.08**	**395.29**	**458.5**
EMV		**73.61**	**88.14**	**102.68**

West Tuzluk Water Injection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						3.00			-3.00	-2.70
2009	1.28	44.74	2.42	1.34	1.34	25.79	5.21	0.00	8.64	7.78
2010	2.17	76.06	4.11	2.28	2.28	0.00	7.00	5.40	54.99	49.49
2011	1.85	64.65	3.49	1.94	1.94	0.00	6.35	21.18	29.75	26.78
2012	1.57	54.96	2.97	1.65	1.65	0.00	5.80	17.39	25.50	22.95
2013	1.33	46.71	2.53	1.40	1.40	0.00	5.33	14.18	21.88	19.69
2014	1.13	39.71	2.15	1.19	1.19	0.00	4.93	14.42	15.83	14.24
2015	0.96	33.75	1.82	1.01	1.01	0.00	4.59	6.05	19.26	17.34
2016	0.82	28.69	1.55	0.86	0.86	0.00	4.30	10.13	10.99	9.89
2017	0.70	24.38	1.32	0.73	0.73	0.00	4.05	8.45	9.10	8.19
2018	0.59	20.73	1.12	0.62	0.62	0.00	3.84	7.02	7.50	6.75
2019	0.50	17.62	0.95	0.53	0.53	0.00	3.66	5.81	6.14	5.52
2020	0.43	14.97	0.81	0.45	0.45	0.00	3.51	4.78	4.98	4.48
2021	0.36	12.73	0.69	0.38	0.38	0.00	3.38	3.90	3.99	3.59
2022	0.31	10.82	0.58	0.32	0.32	0.00	3.28	3.16	3.15	2.84
2023	0.26	9.20	0.50	0.28	0.28	0.00	3.18	2.52	2.44	2.20
2024	0.22	7.82	0.42	0.23	0.23	0.00	3.10	1.99	1.84	1.65
2025	0.19	6.64	0.36	0.20	0.20	0.00	3.04	1.53	1.32	1.19
2026	0.16	5.65	0.31	0.17	0.17	0.00	2.98	1.14	0.88	0.80
2027	0.14	4.80	0.26	0.14	0.14	0.00	2.93	0.81	0.51	0.46
Totals	**14.99**	**524.63**	**28.36**	**15.74**	**15.74**	**29.79**	**80.47**	**129.84**	**224.70**	**202.23**

	Post Tax Cash Flow	Company Share
NPV@10%	**127.70**	**114.93**
NPV@15%	**101.00**	**90.90**
COS%	**14.40**	**14.40**
EMV	**14.96**	**13.47**

RF 0.30

Oil Price Sensitivity	**US$**	**35**	**40**	**45**
NPV@10%		**114.93**	**138.21**	**161.5**
EMV		**13.47**	**16.82**	**20.17**

Tashravat Monocline Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company Share US $ MM
2007						1.00			-1.00	-0.90
2008						1.00			-1.00	-0.90
2009	2.56	89.49	4.84	2.68	2.68	17.67	6.93	0.00	54.68	49.22
2010	4.50	157.50	8.51	4.72	4.72	0.00	10.82	13.49	115.23	103.71
2011	3.82	133.87	7.24	4.02	4.02	0.00	9.47	49.52	59.62	53.66
2012	3.25	113.79	6.15	3.41	3.41	0.00	8.32	41.69	50.81	45.73
2013	2.76	96.72	5.23	2.90	2.90	0.00	7.34	35.03	43.32	38.99
2014	2.35	82.21	4.44	2.47	2.47	0.00	6.51	31.34	34.98	31.49
2015	2.00	69.88	3.78	2.10	2.10	0.00	5.81	13.26	42.84	38.55
2016	1.70	59.40	3.21	1.78	1.78	0.00	5.21	22.44	24.97	22.48
2017	1.44	50.49	2.73	1.51	1.51	0.00	4.70	18.97	21.06	18.96
2018	1.23	42.92	2.32	1.29	1.29	0.00	4.27	16.01	17.74	15.97
2019	1.04	36.48	1.97	1.09	1.09	0.00	3.90	13.50	14.92	13.43
2020	0.89	31.01	1.68	0.93	0.93	0.00	3.59	11.37	12.52	11.26
2021	0.75	26.36	1.42	0.79	0.79	0.00	3.32	9.55	10.48	9.43
2022	0.64	22.40	1.21	0.67	0.67	0.00	3.10	8.01	8.74	7.87
2023	0.54	19.04	1.03	0.57	0.57	0.00	2.90	6.70	7.27	6.54
2024	0.46	16.19	0.87	0.49	0.49	0.00	2.74	5.59	6.01	5.41
2025	0.39	13.76	0.74	0.41	0.41	0.00	2.60	4.64	4.95	4.45
2026	0.33	11.69	0.63	0.35	0.35	0.00	2.48	3.83	4.04	3.64
2027	0.28	9.94	0.54	0.30	0.30	0.00	2.38	3.15	3.27	2.94
Totals	**30.95**	**1083.13**	**58.55**	**32.49**	**32.49**	**19.67**	**96.39**	**308.09**	**535.44**	**481.90**
							NPV@10%		**307.48**	**276.73**
							NPV@15%		**246.19**	**221.57**
							COS%		**32.40**	**32.40**
							EMV		**98.27**	**88.44**

RF	0.34	**Oil Price Sensitivity**	**US$**	**35**	**40**	**45**
		NPV@10%		**276.73**	**331.50**	**397.46**

West Bashkent Water njection Case Post Tax Economics Well Initials 1000 bbls/day

Oil Price US $/bbl **35**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM	Company share US $ MM
2007						1.00			-1.00	-0.90
2008						1.00			-1.00	-0.90
2009	0.91	31.96	1.73	0.96	0.96	7.07	2.56	0.00	18.68	16.81
2010	1.55	54.33	2.94	1.63	1.63	0.00	3.84	4.70	39.60	35.64
2011	1.32	46.18	2.50	1.39	1.39	0.00	3.37	16.81	20.73	18.66
2012	1.12	39.25	2.12	1.18	1.18	0.00	2.98	14.11	17.69	15.92
2013	0.95	33.37	1.80	1.00	1.00	0.00	2.64	11.81	15.11	13.60
2014	0.81	28.36	1.53	0.85	0.85	0.00	2.36	10.77	12.00	10.80
2015	0.69	24.11	1.30	0.72	0.72	0.00	2.11	4.55	14.69	13.22
2016	0.59	20.49	1.11	0.61	0.61	0.00	1.91	7.70	8.55	7.69
2017	0.50	17.42	0.94	0.52	0.52	0.00	1.73	6.50	7.20	6.48
2018	0.42	14.80	0.80	0.44	0.44	0.00	1.58	5.48	6.05	5.45
2019	0.36	12.58	0.68	0.38	0.38	0.00	1.46	4.61	5.08	4.57
2020	0.31	10.70	0.58	0.32	0.32	0.00	1.35	3.88	4.25	3.83
2021	0.26	9.09	0.49	0.27	0.27	0.00	1.26	3.25	3.55	3.19
2022	0.22	7.73	0.42	0.23	0.23	0.00	1.18	2.72	2.95	2.65
2023	0.19	6.57	0.36	0.20	0.20	0.00	1.11	2.27	2.44	2.20
2024	0.16	5.58	0.30	0.17	0.17	0.00	1.06	1.88	2.01	1.81
2025	0.14	4.75	0.26	0.14	0.14	0.00	1.01	1.56	1.64	1.48
2026	0.12	4.03	0.22	0.12	0.12	0.00	0.97	1.28	1.33	1.20
2027	0.10	3.43	0.19	0.10	0.10	0.00	0.93	1.04	1.06	0.96
Totals	**10.71**	**374.73**	**20.26**	**11.24**	**11.24**	**9.07**	**35.40**	**104.92**	**182.61**	**164.35**
							NPV@10%		**94.06**	**84.66**
							NPV@15%		**71.64**	**64.48**
							COS%		**50.00**	**50.00**
							EMV		**46.03**	**41.43**

RF	0.34	**Oil Price Sensitivity**	**US$**	**35**	**40**	**45**
		NPV@10%		**84.66**	**99.78**	**114.9**

Burdalyk Post Tax Economics Gas Case Well Initials 5MMSCF/D

Gas Price US$/1000M3 **61.8** **($1.75/Mcf)**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM
2006						1.00			-1.00
2007						3.00			-3.00
2008	7.31	12.78	0.00	0.38	0.38	16.96	1.70	0.00	-6.64
2009	5.70	9.97	0.00	0.30	0.30	0.00	1.70	1.02	6.66
2010	4.44	7.78	0.00	0.23	0.23	0.00	1.70	0.97	4.64
2011	3.47	6.07	0.00	0.18	0.18	0.00	1.70	0.15	3.86
2012	2.70	4.73	0.00	0.14	0.14	0.00	1.70	0.00	2.75
2013	2.11	3.69	0.00	0.11	0.11	0.00	1.70	1.10	0.67
2014	1.65	2.88	0.00	0.09	0.09	0.00	1.70	0.35	0.66
2015	1.28	2.25	0.00	0.07	0.07	0.00	1.70	0.40	0.01
2016	1.00	1.75	0.00	0.05	0.05	0.00	1.70	0.17	-0.22
2017	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	**29.66**	**51.90**	**0.00**	**1.56**	**1.56**	**20.96**	**15.26**	**4.17**	**8.39**

NPV@10%	**3.48**
NPV@15%	**1.93**
COS%	**23**
EMV	**-2.28**

Burdalyk Post Tax Economics Gas Case Well Initials 5MMSCF/D

Gas Price US$/1000M3 **74.16** **($2.10/Mcf)**

Year	Oil Production MM bbls	Oil Revenue US $ MM	Excise Duty US $ MM	Royalty US $ MM	Taxes Other US $ MM	CAPEX US $ MM	OPEX US $ MM	Income Tax US $ MM	Post Tax Cash Flow US $ MM
2006						1.00			-1.00
2007						3.00			-3.00
2008	7.31	15.34	0.00	0.46	0.46	16.96	1.70	0.00	-4.24
2009	5.70	11.97	0.00	0.36	0.36	0.00	1.70	1.50	8.05
2010	4.44	9.33	0.00	0.28	0.28	0.00	1.70	1.72	5.35
2011	3.47	7.28	0.00	0.22	0.22	0.00	1.70	0.73	4.41
2012	2.70	5.68	0.00	0.17	0.17	0.00	1.70	0.00	3.64
2013	2.11	4.43	0.00	0.13	0.13	0.00	1.70	1.46	1.01
2014	1.65	3.45	0.00	0.10	0.10	0.00	1.70	0.49	1.06
2015	1.28	2.69	0.00	0.08	0.08	0.00	1.70	0.62	0.22
2016	1.00	2.10	0.00	0.06	0.06	0.00	1.70	0.33	-0.06
2017	0.78	1.64	0.00	0.05	0.05	0.00	1.70	0.11	-0.27
2018	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2019	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2021	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2022	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2023	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2024	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals	**30.44**	**63.92**	**0.00**	**1.92**	**1.92**	**20.96**	**16.96**	**6.97**	**15.19**

NPV@10%	**8.26**
NPV@15%	**6.03**
COS%	**23**
EMV	**-1.18**

DWM
Petroleum AG

DWM Petroleum AG
Bahnhofstr. 9
CH-6341 Baar

Telefon 0041-(0)1-7181030
Telefax 0041-(0)1-7181039
e-Mail info@dwm-ag.com

DWM Petroleum AG • Bahnhofstr.9 • CH-6341 Baar

Scott Pickford Limited
4th Floor Leon House
233 High Street
Croydon
United Kingdom

Baar, 14. September 2006

Subject: Update confirmation for the Addendum of the Competent Persons Report dated July 29, 2005 on the Kyrgyzstan assets of DWM Petroleum AG

Dear Sirs

We would like to confirm that since the last CPR dated July 29 no new exploration program has been carried out by the company and hence the company is not in possession of new data concerning the license blocks.

Additionally all 5 licenses have been renewed as well as a new license block Arkyt has been acquired by the company. The table below illustrates the changes to the license area.

Blocks	Entitlement interest (%)	Area (km^2)	Date of Award	Expiry	Renewal Date	Expiry
Nanay	90	999	09.07.2004	09.07.2006	14.06.2006	31.12.2008
Naushkent	90	41	09.07.2004	09.07.2006	14.06.2006	31.12.2008
Soh	90	631	29.04.2004	29.04.2006	29.04.2006	29.04.2010
Tuzluk	90	474	29.04.2004	29.04.2006	29.04.2006	29.04.2010
W Soh	90	160	29.04.2004	29.04.2006	29.04.2006	29.04.2010
Arkyt	90	848	23.08.2005	23.08.2007		

Yours sincerely,

Peter-Mark Vogel
CFO & Member of the Board

DWM Petroleum AG
www.dwm-ag.com • info@dwm-ag.com

Hauptsitz der Gesellschaft: Baar, Schweiz
Register Nummer: CH-020.3.002.974-9

Vorsitzender des Verwaltungsrates:
Dipl. Ing. Heinz-Jürgen Scholz