O A O TATNEFT
Form 6-K
June 29, 2005

FORM 6-K

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16 of

the Securities Exchange Act of 1934

June 29, 2005

Commission File Number 001-14804

OAO TATNEFT

(also known as TATNEFT)

(name of Registrant)

75 Lenin Street

Almetyevsk, Tatarstan 423450

Russian Federation

(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F . . . X . . . . Form 40-F . . . . . .

Indicate by check mark whether the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): . . . . . .

Indicate by check mark whether the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): . . . . . .

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes . . . . . No . . .X. . . .

June 29, 2005

The following report of Miller & Lents, Ltd. dated June 14, 2005 relating to oil and gas reserves of OAO Tatneft was published on the company s web-site today:

[letterhead of Miller & Lents, Ltd.]

June 14, 2005

Mr. Shafagat F. Takhautdinov

General Director

Tatneft Joint Stock Company

75 Lenin Str.

Almetyevsk 423400

Republic of Tatarstan, Russia

Re: Evaluation of Reserves for Tatneft JSC
Reserves and Future Net Revenues Forecast
As of January 1, 2005
Constant Price Case

Dear Mr. Takhautdinov:

At your request, we estimated the net oil and gas reserves and future net revenues as of January 1, 2005, for Tatneft JSC (Tatneft) in certain oil fields of Tatarstan. The properties evaluated are located in the Volga-Ural Oil Basin and include 73 developed and producing oil fields containing approximately 27,800 active completions and 7 undeveloped oil fields. Attachment 1 is a location map of the Republic of Tatarstan that shows the producing areas.

We performed our evaluations, which are designated as the Constant Price Case, using the prices and expenses provided by Tatneft. The Constant Price Case assumes no future escalations of oil or gas prices, operating expenses, capital, or taxes above the respective January 1, 2005 values. The aggregate results of our evaluations for Tatneft are as follows:

	Net Reserves Crude and		**Future Net Revenues**	
	Condensate,	**Gas,**	**Undiscounted,**	**Discounted at**
Reserve Category	**MMBbls.**	**Bcf**	**MM$**	**10% Per Year, MM$**
Proved Developed Producing	3,597.8	762.7	39,126.8	15,110.6
Proved Developed Nonproducing	2,089.3	442.9	20,409.1	3,172.7
Proved Undeveloped	275.5	58.4	2,249.0	362.7

Additional Capital and Property Taxes	0.0	0.0	-3,266.7	-1,363.2
Total Proved	**5,962.5**	**1,264.1**	**58,518.2**	**17,282.7**
Probable	1,262.2	267.6	12,763.6	849.8
Possible	190.2	40.3	1,110.2	5.4

Proved, probable, and possible reserves were estimated in accordance with standards of the Society of Petroleum Engineers, Inc. and World Petroleum Congresses as defined on Attachment 2. The unified tax (previously a combination of royalty, mineral replacement tax, and crude oil excise tax) was deducted from gross revenues in determining net revenues but was not deducted from gross reserves in determining net reserves. Reserves were projected for the economic life of the field, without consideration of production or exploration license terms.

Tatneft also provided us with license term dates. These dates for each field are shown in the Appendix. We estimate the proved reserves and future net revenues as of January 1, 2005 for the time period until the license term date as follows:

For the Time Period Until the License Term Date

	Net Reserves Crude and Condensate,	Gas,	Future Net Revenues Undiscounted,	Discounted at
Reserve Category	**MMBbls.**	**Bcf**	**MM$**	**10% Per Year, MM$**
Proved Developed Producing	1,297.5	275.1	15,734.6	10,760.0
Proved Developed Nonproducing	145.4	30.8	1,813.8	986.3
Proved Undeveloped	56.2	11.9	433.2	200.9
Additional Capital and Property Taxes	0.0	0.0	-1,060.4	-720.7
Total Proved	**1,499.1**	**317.8**	**16,921.2**	**11,226.6**

The estimated proved reserves and future net revenues forecast for the time period following the current license expiration dates are as follows:

For the Time Period After the License Term Date

	Net Reserves Crude and Condensate,	Gas,	Future Net Revenues Undiscounted,	Discounted at
Reserve Category	**MMBbls.**	**Bcf**	**MM$**	**10% Per Year, MM$**
Proved Developed Producing	2,300.3	487.6	23,392.2	4,350.6
Proved Developed Nonproducing	1,943.9	412.1	18,595.3	2,186.4
Proved Undeveloped	219.3	46.5	1,815.8	161.8
Additional Capital and Property Taxes	0.0	0.0	-2,206.3	-642.5
Total Proved	**4,463.4**	**946.3**	**41,597.0**	**6,056.1**

Future net revenues as used herein are defined as the total gross revenues less unified tax, operating costs, and capital expenditures. The total gross revenues are the total revenues received by Tatneft after deduction of transportation costs, export and customs duties, port expenses, excise tax, value added tax, and special taxes. The oil and gas prices employed in the computations of gross revenues were provided by Tatneft and are shown on Attachment 3. Future net revenues do not include deductions for either federal or local taxes on net profit.

The operating expenses employed in estimating future net revenues are the average operating expenses for the year 2004 that were provided by Tatneft. We removed from the operating expenses the depreciation, well restoration costs, and the unified tax. Restoration costs were included as capital for the portion of the proved nonproducing reserves attributed to the restoration of shut-in wells. The operating expenses for Tatneft are shown on Attachment 4.

We allocated a portion of the operating expenses to the number of active wells on a per-well basis and the remainder to the oil production rates on a per-barrel basis, employing the allocations provided to us by Tatneft. We assumed that the number of active wells for the large waterfloods would decline to approximately one-half the fully developed well count estimated in last year's evaluation as the fields declined in production and approached their economic limit.

Future capital costs for drilling and workover operations are based on 2004 costs provided by Tatneft and are shown on Attachment 5. The forecasts for capital expenditures, other than drilling and completions, were based on data provided by Tatneft through the year 2021 and are shown on Attachment 6.

The proved developed producing reserves and production forecasts were estimated by production decline extrapolations, or in a few cases, by volumetric calculations. For some reservoirs with insufficient performance history to establish trends, we estimated future production by analogy with other reservoirs having similar characteristics. Production declines were extrapolated to economic limits based on operating cost and oil

price data. The past performance trends of many reservoirs were influenced by production curtailments, workovers, waterfloods, and/or infill drilling; extrapolations of future performance are based, whenever possible, upon the average performance trend of active wells during periods of stable field activity.

The estimated proved developed nonproducing reserves can be produced from existing well bores but require capital costs for workovers, recompletions, or restoration of shut-in wells. For wells shut in awaiting mechanical repair, we assumed that the wells producing at rates greater than the economic limit at the time of shut in will be returned to production at pre-shut-in levels and will decline in production at the average reservoir decline rate. For wells requiring recompletion, the estimates of reserves and producing rates are based on volumetric calculations and analogies with other wells that commercially produce from the same formation in the same field.

The estimated proved undeveloped reserves require significant capital expenditures, such as (1) costs for future development and infill wells and (2) surface facilities. The proved undeveloped reserves are expected to be produced from undeveloped portions of known reservoirs that have been adequately defined by wells. Reserve estimates are based upon volumetric calculations that employ recovery factors based on the performance of analogous reservoirs. Producing rates are based upon analogy.

The estimated probable and possible reserves are mainly undeveloped and require significant capital expenditures. As new wells are drilled, portions of these probable and possible reserve quantities will be either upgraded to a higher reserve category or dropped entirely. The estimated probable reserves are expected to be produced from undeveloped portions of known reservoirs not adequately defined to be classified as proved. Another component of probable reserves was included for reservoirs with water-oil ratio trends that indicated higher reserves than calculated from linear production decline curve analyses. For these reservoirs, future production was assumed to decline hyperbolically, and the incremental production above the linear decline was classified as probable. The estimated possible reserves are expected to be produced from undeveloped portions of known reservoirs (1) where the reservoir is thin and uncertain to be developed or (2) where subsurface control is limited. Estimates of reserves for undeveloped portions of known reservoirs were estimated by volumetric methods.

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

The probable and possible reserve volumes and the estimated future net revenues therefrom have not been adjusted for uncertainty. None of the proved, probable, or possible reserve volumes, nor the revenues projected therefrom, should be combined with either of the other without adjustment for uncertainty. Estimates of future net revenues and discounted future net revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves. Future costs of abandoning facilities and wells and any future costs of restoration of producing properties to satisfy environmental standards were not deducted from total revenues as such estimates are beyond the scope of this assignment.

Estimated net gas reserves are based upon the past ratio of sales gas to produced oil. Net gas reserves do not represent the total volumes of gas expected to be produced with the net oil reserves.

Structural maps, isopach maps of net oil sand, well status maps, seismic data, cross sections, oil and water production data, well logs and core information on key wells, and the Tatneft interpretation of key reservoir parameters were provided by Tatneft. These were reviewed in detail and were generally found to be acceptable interpretations. In certain cases, where appropriate, original maps were prepared. The reservoir maps were employed to estimate original oil in place and to classify the potentially productive areas as either proved developed producing, proved

developed nonproducing, proved undeveloped, probable, or possible. Volumetric methods were employed to estimate the original oil in place for each classified area.

Attachments 7a and 7b show a composite production forecast for Tatneft in barrels and tonnes, respectively. These figures show the contribution of production from each proved reserve category. Following the attachments are one-line summaries in both barrels and tonnes that show reserves and cumulative future net

revenues for each evaluated field. Tatneft assigned fields to specific groups, which are also identified in the one-line summaries.

Following the one-line summaries are exhibits that are projections of future production and net revenues for each reserve category and group.

In conducting this evaluation, we relied upon (1) production histories, (2) accounting and cost data, (3) ownership, (4) geological, geophysical, and engineering data, and (5) drilling, recompletion, and workover schedules supplied by Tatneft. These data were accepted as represented, as verification of such data and information was beyond the scope of this assignment.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgments based on accepted standards of professional investigation but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical, and engineering information. Government policies and market conditions different from those employed in this study may cause the total quantity of oil or gas to be recovered, actual production rates, prices received, or operating and capital costs to vary from those presented in this report.

Miller and Lents, Ltd. is an independent oil and gas consulting firm. No director, officer, or key employee of Miller and Lents, Ltd. has any financial ownership in Tatneft or any related company. Our compensation for the required investigations and preparation of this report is not contingent on the results obtained and reported, and we have not performed other work that would affect our objectivity. Preparation of this report was supervised by an officer of Miller and Lents, Ltd., who is a professionally qualified and licensed Professional Engineer in the State of Texas with more than 20 years of relevant experience in the estimation, assessment, and evaluation of oil and gas reserves.

Yours very truly,

MILLER AND LENTS, LTD.

By /s/ James C. Pearson

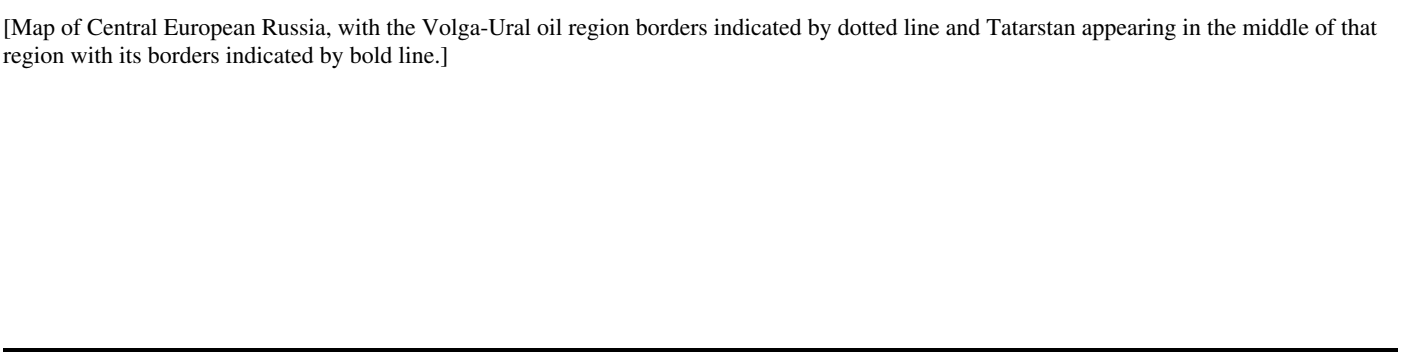
James C. Pearson
Chairman
JCP/mk

LIST OF ATTACHMENTS

Attachment 1

Location Map

Russian Federation, Tatarstan


[Map of Central European Russia, with the Volga-Ural oil region borders indicated by dotted line and Tatarstan appearing in the middle of that region with its borders indicated by bold line.]

Attachment 2

Definitions for Oil and Gas Reserves

Definitions

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further subclassified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called probabilistic when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Proved Reserves

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

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

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering, or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

Unproved Reserves

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

Probable Reserves. Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context,

when probabilistic methods are used, there should be at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

Possible Reserves. Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

Reserve Status Categories

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

Developed. Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be subcategorized as producing or nonproducing.

Producing. Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Nonproducing. Reserves subcategorized as nonproducing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are

expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves. Undeveloped reserves are expected to be recovered (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Approved by the Board of Directors, Society of Petroleum Engineers (SPE), Inc., and the Executive Board, World Petroleum Congresses (WPC), March 1997.

Attachment 3

TATNEFT JOINT STOCK COMPANY
OIL AND GAS PRICING

December 2004

A.	**Export Oil Price**		**$US/Tonne**		**RR/Tonne**
	Contract Price		**235,98**		**6548,35**
	Less:	Transportation	10,87		301,68
		Export Tariffs	78,20		2170,06
		Other Expenses for Export	3,58		99,37
		Customs Duties	0,26		7,19
		Commissions	0,81		22,37
	Total Deductions		**93,72**		**2600,67**
	Net Export Oil Price		**142,26**		**3947,68**
	Percent Oil Exported (Yearly Average)		**58,8%**		
B.	**Export Oil Price (CIS Countries)**		**$US/Tonne**		**RR/Tonne**
	Contract Price		**269,84**		**7488,05**
	Less:	Transportation	7,70		213,75
		Customs Duties	0,40		11,17
		Commissions	0,10		2,73
		VAT	41,16		1142,25
		Other Expenses for Export	0,09		2,56
	Total Deductions		**49,46**		**1372,45**
	Net Export Oil Price		**220,38**		**6115,60**
	Percent Oil Exported (Yearly Average)		**18,7%**		
C.	**Domestic Oil Price**		**$US/Tonne**		**RR/Tonne**
	Contract Price		**154,85**		**4296,99**
	Less:	VAT	23,62		655,47
		Excise Tax	4,37		121,30
	Total Deductions		**27,99**		**776,77**
	Net Domestic Oil Price		**126,85**		**3520,22**
		/Tonne	**$153,372**	**/Tonne**	
	AVERAGE NET OIL PRICE				
		/Bbl	**$21,532**	**/Bbl**	
D.	**Export Gas Price**		**$US/1000m3**		**RR/1000m3**
	Contract Price		**261,62**		**7259,95**
	Less:	Transportation	56,05		1555,37
		Other Expenses for Export	40,32		1118,85
		Excise Tax	0,00		0,00
	Total Deductions		**96,37**		**2674,22**
	Net Export Gas Price		**165,25**		**4585,73**
	Percent Gas Exported (Yearly Average)		**13,5%**		
E.	**Domestic Gas Price**		**$US/1000m3**		**RR/1000m3**
	Contract Price		**102,72**		**2850,46**

Less:	VAT		16,22		450,00
	Excise Tax		0.00		0.00
Total Deductions			**16,22**		**450,00**
Net Domestic Gas Price			**86,50**		**2400,46**
		/1000m3	**$97,13**	**/1000m3**	
AVERAGE NET GAS PRICE					
		/MCF	**$2,751**	**/MCF**	
2004 Gas Sales Volume			39 376 444	MCF	
2004 Oil Sales Volume			185 875 075	Bbl	
RATIO OF GAS SALES TO OIL SALES			**0,212**	**MCF/Bbl**	

Conversion Factors:

	Bbl per Tonne	7,123
	RR per U.S. $	27,75

Attachment 4

Tatneft Joint Stock Company
2004 Operating Expenses

	Cost Item	Total, M$
1	Power to Recover Oil	48 883
2	Formation Pressure Maintenance	158 080
3	Field Workers' Main Salary	12 261
4	Field Workers' Additional Salary	1 465
5	Social Insurance	3 554
6	Well Depreciation	46 625
7	Oil and Gas Collection and Transportation	54 487
8	Oil Treatment	44 627
9	Preparatory work	-
10	Equipment Maintenance and Operation	303 385
11	including Well Maintenance Services	81 289
12	Shop Expenses	58 060
13	General Production Expenses including:	336 797
13	Road Tax	1 289
13	Housing Deductions	-
14	Production Taxes including:	939 306
14	Royalty taxes (OAO Tatneft)	305
		-
	Subtotal	305
14	Production tax (OAO Tatneft)	939 001
		-
	Subtotal	939 001
15	**Gross Production Costs**	**2 007 529**
16	Depreciation of oil wells	46 625
17	Estimate of Recompletions and Restorations	71 731
18	Production Taxes	939 306
19	**Total Deductions**	1 057 662
20	**NET OPERATING EXPENSE**	**949 867**
	Production in thousand tonnes:	**25 763**
	Exchange Rate: (RR per US$):	**27,75**
	Average Monthly Operating Costs, US$:	**79 156**
	Active Well Completions:	**27 462**
	Average Monthly Oil Production, MTonnes:	**2 147**
	Average Monthly Oil Production, MBarrels:	**15 293**
0,65	of Operating Costs Based on Well Count	
0,35	of Operating Costs Based on Oil Production	

Operating Cost:	**$ 1 874 per well per mo.** **$ 1,81 per barrel**

Attachment 5

TATNEFT JOINT STOCK COMPANY
2004 AVERAGE CAPITAL INVESTMENT

Drill and Completion

Tatneft Properties		
Carboniferous	$ 325 034	per well
Devonian	$ 359 594	per well

Recompletion

Tatneft Properties	$ 22 783	per well

Restoration of Shut-in Wells

Tatneft Properties	$ 18 451	per well

Attachment 6

TATNEFT JOINT STOCK COMPANY

Forecast of Other Capital Investments

Thousand US Dollars

(Does not include CAPEX for drilling and recompletion of wells and well workovers)

Data Source	Year	M $US
	2005	$ 92 644
	2006	$ 93 656
	2007	$ 100 739
	2008	$ 108 160
	2009	$ 116 255
	2010	$ 125 025
	2011	$ 134 357
	2012	$ 144 476
	2013	$ 155 269
	2014	$ 166 962
	2015	$ 179 442
	2016	$ 192 934
	2017	$ 207 438
	2018	$ 222 954
	2019	$ 239 706
	2020	$ 257 695
	2021	$ 277 034
	Total 2005 - 2021	$ 2 814 746

Attachment 7a

Attachment 7b

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

OAO TATNEFT

By: /s/ Vladimir P. Lavushchenko
Name: Vladimir P. Lavushchenko

Title: Deputy General Director for Economics,

Chairman of Disclosure Committee

Date: June 29, 2005