Urals Energy Public Company Limited
Preliminary Results for the year ended 31 December 2005

Urals Energy Public Company Limited (LSE: UEN), the international oil and gas exploration and production company which was admitted to the Alternative Investment Market of the London Stock exchange in August 2005, raising US$131 million, today announces its preliminary results for the year ended 31 December 2005.

In a separate announcement today, the Company announced the signing of a definitive Sales Purchase Agreement for the $148 million acquisition of the significant Dulisminskoye oil, condensate and gas field together with the LTK transportation and treating facilities, all located in the Irkutsk region of Eastern Siberia, close to Transneft's proposed East Siberian Pipeline. The Dulisminskoye Field is currently producing 1,000 bopd and Urals Energy intends to move rapidly to increase production from this field through infield development to approximately 12,000 bopd by the end of 2008 and approximately 30,000 bopd by 2011.

Operating Highlights:

- Completion and integration of ZAO Arcticneft, OOO Dinyu and OOO Urals Nord acquisitions
- Near fivefold increase in average annual production from 1,146 to 5,263 bopd
- Current production increased to 9,000 bopd
- 2P reserves rose 31% to 116 million barrels (2004: 89.6 million barrels)
- 107% reserve replacement at a cost of $2.50 per barrel due to successful development drilling

Financial and Corporate Highlights

- Admission to AIM and $131 million equity raising in August 2005
- Turnover increased to $92.9 million (2004: $8.2 million)
- Operating profit of $11.3 million (2004: loss of $3.7 million)
- Post tax profit of $7.1 million (2004: loss of $3.6 million)
- Adjusted EBITDA of $16.9 million

Outlook

- $40 million capex plan (excluding Dulisma acquisition) across 20 new development wells and 2 high impact exploration wells
- Production (excluding Dulisma acquisition) targeted to increase by 33% to approximately 12,000 bopd by end 2006
- Integration and development of Dulisma acquisition projected to add incremental 12,000 bopd to group production by end 2008
- Continued focus on acquiring under exploited assets in Russia and the FSU

<u>William R. Thomas, Chief Executive Officer, commented:</u>

"2005 was a landmark year which saw Urals Energy establishing a solid production and operational base in Russia which has delivered strong financial results.

The outlook for 2006 is excellent with an intense development and exploration programme planned which will further increase production.

Today's announcement of the proposed acquisition of the Dulisma Field is an important development for Urals giving us significant oil and gas reserves at an attractive price and strategically located near the proposed East Siberia pipeline."

18 April 2006

Pelham PR

James Henderson	020 7743 6673
Gavin Davis	020 7743 6677

CHAIRMAN'S AND CHIEF EXECUTIVE'S STATEMENT

2005 was a landmark year for Urals Energy - we outperformed our initial objectives and built on our solid reserve and production base. Our strategy of growing the company through development, exploration and acquisition is already generating significant returns for shareholders. During the year we made three successful acquisitions (ZAO Arcticneft, OOO Dinyu and OOO Urals Nord), average yearly production increased almost fivefold from 1,146 to 5,263 bopd and current production increased to 9,000 bopd resulting in an increased target of at least 14,000 bopd by the end of 2007. Proved and probable reserves rose significantly from 89.6 to 116 million barrels, or approximately 31%, and we replaced 107% of our produced reserves through development drilling at a cost of approximately $2.50 per barrel. We also began an important exploration programme offshore Sakhalin Island.

Underpinning this growth was the $131 million of new equity capital we raised in our August 2005 IPO on the Alternative Investment Market (AIM) of the London Stock Exchange.

Urals Energy's continued growth is based on a three-pronged strategy of (i) increasing production through low-risk development drilling, (ii) adding reserves by exploring our resource base offshore Sakhalin Island and onshore Timan Pechora, and (iii) making new and larger acquisitions of Russian oil companies. It is a strategy intended to create a balanced portfolio of upstream assets which is managed and developed in a highly efficient and cost effective manner. The cost to acquire and develop our proved and probable reserves to date is approximately $1.73 per barrel, not including the Dulisma acquisition announced separately today. We believe this is a proven strategy that will continue to deliver significant returns to our shareholders.

Financial Results

In 2005, Urals Energy focussed on the acquisition and development of new companies and assets and their integration into the Group. Our three new acquisitions are consequently reflected in our overall financial results: revenues totalled $93 million, adjusted EBITDA was $17 million, and profits after tax were $7 million – all of which were significant increases over 2004's results. Prices received for oil and products sold in 2005 averaged $43.24 and $51.89 per barrel respectively while overall netback prices (gross price less export taxes, transport and marketing costs and net of VAT) averaged $30.02 per barrel. The price for domestic oil sold in Russia increased dramatically in 2005 from approximately $15 to $30 per barrel. This is the result of increased domestic demand and improved margins for Russian refineries, a trend we expect to continue during 2006.

Total cash operating costs were approximately $12 million, excluding DD&A, production taxes, and other non-cash items. On a per barrel basis and as compared to revenues, our cost structure is higher than other more mature production operations in Russia. This is the result of acquiring only partially developed fields and consolidating seven stand-alone companies within two years. As we execute our development plans and production volumes grow, our per barrel operating costs are expected to decline and profits increase commensurately. We also expect to lower operating costs in our producing subsidiaries by reducing headcount and streamlining operations.

We ended the year with $32.3 million in cash after having acquired OOO Dinyu for $70 million cash in November 2005. In the same month, we closed a $100 million revolving five year reserve-based lending facility with BNP Paribas. The net amount drawn against this facility at year-end was $69 million. We are pleased by the inherent recognition of creditworthiness this facility provides us. It is now in syndication and preliminary results are very encouraging.

At 31 December 2005, our balance sheet was funded with approximately $200 million in shareholders equity and $81 million of bank and subordinated debt. We believe this is a prudent debt to equity ratio for a rapidly growing business like Urals Energy.

During 2006, we expect to maintain our planned level of capital expenditure of approximately $40 million (excluding the proposed development spend on the Dulisma acquisition announced today), almost all of which will be invested in increasing production. By the end of 2006, our plan is to increase production to approximately 12,000 BOPD from our existing assets. This should result in a sustainable core production base that is generating strong cash flow and the opportunity for further growth.

Operations

Sakhalin Island

At ZAO Petrosakh, both exploration and development activity continues at a rapid pace.

Testing continues on our first offshore exploration well, East Okruzhnoye No. 1, in the Pogranichny Block offshore Sakhalin Island, and results are expected shortly.

Further planned exploration work during 2006 includes a second exploration well, seismic studies and preparations for a possible marine drilling program in 2007. We recently awarded a tender for the processing and interpretation of a combined onshore and offshore 3D seismic data set that should further enhance our understanding of both the onshore Okruzhnoye Field and the eleven exploration prospects that lie directly offshore. Following the extension of our offshore license for an additional five years, we believe a logical next step is to drill several vertical exploration wells to test our best offshore prospects. This will require mobilizing a marine drilling unit, probably a jackup, and extensive pre-drilling preparations. Further details of this program will be announced later in 2006.

As previously announced, the further development of the onshore Okruzhnoye Field has been deferred until the interpretation of a new 3D seismic program is completed. We have acquired a new mobile Russian drilling rig for this field and expect development drilling to begin in June 2006. A total of three new development wells and three re-entries are planned this year for the Okruzhnoye Field.

We have also begun preparations for a fracture stimulation program at Petrosakh and our other oil producing subsidiaries. Equipment has been purchased in western Canada and is being refurbished prior to shipment to Sakhalin Island this summer. Given the reservoir characteristics of the Okruzhnoye Field, we expect good results from fraccing. After completing the Okruzhnoye Field stimulation program, we will move the equipment to Komi and Timan Pechora where we also believe we will boost production by fraccing.

Komi Republic and Timan Pechora

The acquisition of OOO Dinyu helped create a new core area for Urals Energy in the Komi Republic which sits in the southern half of the prolific Timan Pechora basin. In Komi, we produce from three fields at Dinyu and CNPSEI. Development operations have continued at Dinyu since its acquisition with the drilling of two producing wells, numbers 32 and 51. For Dinyu in 2006, we expect to drill a total of nine development wells and one exploration well and have set a year-end production target of approximately 4,000 BOPD.

Further north, the Timan Pechora basin extends to the Nenets Autonomous Okrug where we have two operating subsidiaries, Arcticneft and Urals Nord. At Arcticneft, we are now completing a comprehensive geological model to assist in selecting well locations in preparation for our development drilling programme this summer. During 2006, we expect to drill four development wells at Arcticneft.

At Urals Nord, we are planning on drilling our first exploration well to test the Nadezhdinsky prospect. Situated approximately 60 kilometers from the port of Varandey, this prospect has high impact potential and if successful would be developed to deliver oil to the LUKoil terminal now under construction at Varandey.

Udmurtia

Our production and development operations at Chepetskoye NGDU continue on track with the recent completion of the 3D seismic interpretation of the Potaposkvoye Field. Development drilling operations will begin shortly for a planned four well program in 2006.

Corporate

In line with our strategy, we are actively reviewing a number of new acquisition opportunities, as evidenced by today's announcement of the proposed acquisition of the Dulisma Field. The number and quality of potential acquisition opportunities remain strong. Our business model is to acquire under-exploited assets in Russia and the FSU, invest in development and exploration, and monetize through either production or divestiture at the appropriate time. This consolidation strategy is a proven business model, and we believe we have the track record, highlighted by our acquisition and development costs to date of $1.73 per barrel, to execute such strategies. With a strong track record of success, Urals Energy is well positioned to take advantage of this attractive market opportunity.

Outlook

The outlook for 2006 is positive. Production volumes are expected to grow to approximately 12,000 BOPD by year-end as we further develop our oil fields across Russia by drilling 20 new development wells. This development plan also includes the introduction of new, mobile fracture-stimulation equipment designed to quickly enhance production for an attractive cost. Our high-impact exploration program offshore Sakhalin Island is expected to continue with enhanced data and further developed understanding of the geology and petroleum system. We also expect to spud our first exploration well in northern Timan Pechora. Financially, the Group expects to generate stronger cash flow and profits. Additionally, we continue to examine a number of potential acquisition opportunities.

The Russian government is considering certain changes to the existing oil tax regime. Should this occur in 2006, it could have a significant financial impact on Urals Energy as we operate in many of the frontier areas that may become eligible for tax holidays and other investment incentives. Revenue-based taxes are our single largest cost item, approximately 29% of gross revenues, and we and the industry as a whole continue to maintain an active dialogue with the government on this important issue.

Finally, the backbone of our company and its most important advantage are our employees. They have helped transform Urals Energy over the past 12 months to become a successful international E&P company producing 9,000 BOPD with reserves of 116 million barrels and a current market capitalization of approximately $600 million. It is their hard work, enthusiasm and skill that makes Urals Energy successful.

Viatcheslav V. Rovneiko
Chairman of the Board

William R. Thomas
Chief Executive Officer

18 April 2006

FINANCIAL REPORT

Operating Environment

2005 was characterized by strong increases in world oil and gas prices and a surge in exploration and production activity and investment. Brent oil prices began the year at $39.50 per barrel, reached a peak of $67.49 per barrel and ended the year at $58.21 per barrel. The Russian oil industry was similarly affected by this changing price environment. Industry average domestic oil prices began at $13 per barrel and averaged approximately $29 per barrel for the year. Russian export prices rose with world market prices and resulted in steadily increasing export taxes that absorbed much of the net export revenue available to producers. This loss of export revenues was mostly offset by the increase of domestic prices and resulting netback parity.

Increased oil and gas prices, particularly domestic prices, have resulted in stronger demand for oilfield services in Russia. Rig availability for certain types of specialized drilling is declining. Overall production costs are increasing due to rising industry demand and the strengthening Rouble.

Production and Revenues

Crude oil production during the year increased by 359% from 418,000 barrels in 2004 to 1.92 million barrels in 2005, with average daily production increasing from 1,146 barrels per day in 2004 to 5,263 in 2005. The total production increase of 4,117 bopd was the result of both development drilling (740 bopd) and additions from acquisitions (3,377 bopd).

During the period the Company's gross revenues totalled $92.9 million versus $8.2 million in 2004. Net revenues increased to $66.1 million from $7.4 million in the prior year. This revenue increase is the result of both the Group selling 2.1 million barrels of additional crude oil and products than in 2004 and higher commodity prices. The Group realized a weighted average price of $43.24 per barrel of oil sold in 2005. Export sales prices for the Group averaged $49.29 per barrel, and domestic sales prices averaged $28.96 per barrel. Domestic refined product prices averaged $51.89 per barrel.

Net revenues received by the Company strengthened during the year as world oil prices increased and the disparity between export and domestic prices narrowed. Net revenues for 2005 totalled $66.1 million as compared to $7.4 million in 2004. Netback prices are defined as, in the case of exports, gross oil sales price less export duty, customs charges, marketing costs and transportation, and, in the case of domestic crude sales, gross sales price net of VAT. The weighted average netback for crude oil sales during 2005 was $29.38 per barrel. Netbacks for export sales were $31.36 per barrel and $24.15 per barrel for domestic sales. Netback prices for domestic product sales are defined as gross product sales price minus VAT, transportation, excise tax and refining costs. The average products netback for the year was $34.87 per barrel.

Gross profit for the year, (net revenues minus the cost of production), was $15.5 million as compared to $3 million in 2004. Production costs totalled $50.4 million but included $20.7 million of non-cash items. These non-cash charges included $12.5 million of crude oil inventory in place at Arcticneft when acquired and subsequently sold at a zero book profit margin. Because of these non-cash items included in its cost of production, the Company believes the strength of the Group's operating performance is not fully reflected in its gross profit result.

SG&A costs increased to $13.9 million as compared to $4.4 million in 2004. The largest component increase in SG&A, wages and salaries, reflects a significantly increased workforce and management team due to acquisitions and increased scope of activity. Total audit and professional fees reflected the Company's continued growth through acquisitions and related financing activities.

Interest expense for the period was $6.9 million as compared to $574 thousand in 2004. Increased interest expense primarily reflects the cost of financing acquisitions and capital expenditures. $5.5 million of this was directly related to interest on acquisitions payments.

Net profit for the year attributable to shareholders was $7.1 million as compared to a loss of $3.7 million in 2004. Basic earnings per share were 12 cents versus a loss of 19 cents in 2004.

Adjusting for the Arcticneft inventory purchase, non-recurring mobilization costs and other standard non-cash items, the Company's management-adjusted EBITDA for the period was $16.9 million, or 24.6% of net revenues. Including the full-year results of two companies acquired during 2005, Arcticneft and Dinyu, pro-forma management-adjusted EBITDA was $22.6 million. At 31 December 2005 and based on year-end prices, an additional $3.9 million in potential revenues and $1.9 million in EBITDA was held in the crude oil inventories at Petrosakh and Arcticneft and stored for export in 2006.

Taxes

Russia has a relatively high cost tax regime and the Company pays a variety of taxes that are levied as a result of production, exported oil, assets and profits. The largest taxes for the Group as a percentage of revenues during 2005 were export duties (29%) and the unified production tax (18%). The Company paid a total of $69.6 million in cash taxes for the year. Unified production taxes are calculated based on production revenues and in 2005 the Group paid $24.5 million. Export duties are set according to a fixed schedule that increases as export prices rise with a maximum rate of 65% of gross export prices above $25 per barrel. High export prices in 2005 resulted in an average export duty for the Company of 40%, and $23.2 million of cash paid. VAT payments totalled $12.5 million.

At 31 December 2005, the Group's deferred tax liability was $51.1 million. This is a non-cash liability and is the result of the difference between the Group's consolidated IFRS-calculated profit taxes versus actual taxes paid by the Group's operating subsidiaries. The Company expects this deferred tax liability to be reflected on its balance sheet indefinitely.

Cash Flow

For the period, operating cash flow before working capital changes was $3.9 million. Changes in working capital resulted in a negative cash flow from operations of $27.6 million. This is primarily due to a combined $12.4 million increase in receivables for crude oil sales plus increased tax prepayments, and a decrease in payables to suppliers compared with the start of the year. Capital expenditures for exploration and development in 2005 were $16.4 million of which $13.2 million was invested at Petrosakh, and $2.5 million at Chepetskoye

NGDU. The cost of acquisitions during 2005 was $93.7 million, resulting in a total use of cash of $156.8 million.

At 31 December 2004, the Group's short and long-term debt was $38.5. During 2005, a total of $101.4 million in new debt was borrowed and $82.6 million in debt repaid or converted to equity. As of 31 December 2005, total outstanding debt was $81.1 million.

Through both a private-placement of common stock and the primary sale of shares in a public offering, the company raised $150.7 million in cash. The combination of debt and equity financing activities resulted in a total addition to cash of $187.8 million.

Cash Position

The combined use of $156.8 million for operations, acquisitions and capital expenditures was funded by the net addition of $187.8 million in cash from borrowings and the sale of equity. This resulted in a change to the cash position of $30.9 million by year end.

Hedging

The Company does not hedge any of its crude oil or product sales, costs or currency conversions.

International Financial Reporting Standards (IFRS)

On 23 February 2006, the Company restated the interim results ending 30 June 2005. The restated results resulted in a net loss of $800,000 as compared with the originally announced net loss of $1.145 million. The difference was primarily the result of minor adjustments in gross revenues, cost of production, and interest costs and had no material effect on the Company's cash flows.

The implementation of IFRS accounting procedures has resulted in a number of non-cash adjustments and non-recurring costs in the accounts. Management believes that certain large items distort the actual cash operating characteristics of the business.

As previously mentioned, the Company's deferred tax liability of $51.1 million is a non-cash item and is due to the difference between the Group consolidated profit taxes calculated for IFRS purposes versus those actually paid by each subsidiary as federal income taxes are accrued. These amounts are not due for payment by the Company, and are likely to continue to increase in subsequent statements.

Under IFRS purchase accounting, the excess of the purchase price paid for a property over the fair market value of its tangible assets must be depleted over time using a unit of production formula. The result is an increase to the Company's Depreciation and Depletion, and will adjust depending on the estimate of future proven and producing barrels of oil.

IFRS treatment for the excess of the fair market value of the tangible assets at Arcticneft over the amount paid for the business by the Company resulted in $16.8 million of negative goodwill for the period. This non-cash item increased operating profits by a corresponding amount.

Under IFRS methodology, the Company applies successful efforts accounting to exploration and development expenses. Certain expenses have been capitalized pending the determination of the success of the related exploration or development program. The non-recurring mobilization costs for the period relate to the cost of mobilizing an exploratory drilling rig that was not ultimately used for drilling. This expense item is not included in cost of production.

Urals Energy Public Company Limited
Consolidated Balance Sheets
(presented in US$ thousands)

	Note	31 December: 2005	2004
Assets			
Current assets			
Cash and cash equivalents		32,334	1,395
Restricted cash		-	26
Accounts receivable and prepayments	5	23,788	3,706
Inventories	6	12,641	2,773
Total current assets		68,763	7,900
Non-current assets			
Property, plant and equipment	7	287,485	102,754
Other non-current assets		2,098	292
Total assets		358,346	110,946
Liabilities and equity			
Current liabilities			
Accounts payable and accrued expenses	8	7,932	3,748
Income taxes payable	9	6,039	387
Other taxes payable	9	5,448	1,530
Short-term borrowings and current portion of long-term borrowings	10	34,117	38,486
Advances from customers		523	5,103
Amount due for acquisition of ZAO Petrosakh	4	-	9,899
Total current liabilities		54,059	59,153
Long-term liabilities			
Long-term borrowings	10	47,005	-
Long-term finance lease obligations		1,357	1,556
Dismantlement provision	11	813	950
Deferred tax liability	9	51,100	18,390
Other long term liabilities		580	1,590
Total long-term liabilities		100,855	22,486
Total liabilities		154,914	81,639
Equity			
Share capital	12	460	209
Share premium	12	201,355	42,172
Unpaid capital	12	-	(11,324)
Translation difference		(2,296)	1,264
Retained earnings (accumulated deficit)		2,714	(4,341)
Equity attributable to shareholders of Urals Energy Public Company Limited		202,233	27,980
Minority interest		1,199	1,327
Total equity		203,432	29,307
Total liabilities and equity		358,346	110,946

Urals Energy Public Company Limited
Consolidated Statements of Operations
(presented in US$ thousands)

	Note	Year ended 31 December: 2005	2004
Revenues			
Gross revenues	13	92,918	8,184
Less: excise taxes and export duties		(26,783)	(783)
Net revenues		66,135	7,401
Operating costs			
Cost of production	14	(50,442)	(4,352)
Selling, general and administrative expenses	15	(13,968)	(6,825)
Non-recurring mobilization costs	16	(7,170)	-
Excess of net assets acquired over purchase price	4	16,793	-
Total operating costs		(54,787)	(11,177)
Operating profit (loss)		11,348	(3,776)
Interest income		913	82
Interest expense		(6,911)	(574)
Foreign currency gains (losses)		(185)	211
Other non-operating gains (losses)		(457)	222
Income (loss) before income tax		4,708	(3,835)
Current income tax	9	(890)	(103)
Deferred income tax benefit	9	3,155	280
Profit (loss) for the period		6,973	(3,658)
Attributable to			
Minority interest		(82)	14
Shareholders of Urals Energy Public Company Limited		7,055	(3,672)
Earnings (loss) per share of profit attributable to shareholders of Urals Energy Public Company Limited (adjusted for share split and expressed in US dollars per share)			
- Basic earnings per share		0.11	(0.1898)
- Diluted earnings per share		0.11	(0.1898)
Weighted average shares outstanding			
- Basic earnings per share		59,915,473	19,344,262
- Diluted earnings per share		59,939,038	19,344,262

Urals Energy Public Company Limited
Consolidated Statements of Cash Flows
(presented in US$ thousands)

		Year ended 31 December:	
		2005	**2004**
Cash flows from operating activities			
Profit (loss) before income tax		4,708	(3,835)
Adjustments for:			
Depreciation and depletion		9,394	522
Non-cash expenses		42	1,928
Interest income		(913)	(82)
Interest expense		6,911	574
Loss on disposal of long-lived assets		640	-
Excess of net assets acquired over purchase price		(16,793)	-
Effect of currency translation		185	211
Other non-cash transactions		(213)	-
Operating cash flows before changes in working capital		3,961	(682)
Decrease (increase) in inventories		3,234	(374)
Increase in accounts receivables and prepayments		(12,374)	(1,097)
Increase (decrease) in accounts payable and accrued expenses		(18,644)	2,152
Decrease in other current assets		178	-
Decrease in income and other taxes payable		(785)	(140)
Increase in other liabilities and provisions		(3,182)	307
Cash generated from (used in) operations		(27,612)	166
Interest received		913	52
Interest paid		(2,685)	-
Income tax paid		(2,862)	-
Net cash generated from (used in) operating activities		(32,246)	218
Cash flows from investing activities			
Acquisitions of subsidiaries, net of cash acquired	4	(106,500)	(39,976)
Purchase of property, plant and equipment		(18,087)	(1,146)
Acquisition of associates		-	(264)
Net cash used in investing activities		(124,587)	(41,386)
Cash flows from financing activities			
Proceeds from borrowings		101,412	28,937
Repayment of borrowings		(56,313)	-
Finance lease principle payments		(404)	-
Contributions from shareholders		-	871
Cash proceeds from issuance of ordinary shares		143,100	12,797
Net cash generated from financing activities		187,795	42,605
Effect of exchange rate changes on cash and cash equivalents		(49)	(26)
Net increase in cash and cash equivalents		30,913	1,411
Cash and cash equivalents at the beginning of the period		1,421	10
Cash and cash equivalents at the end of the period		32,334	1,421

Urals Energy Public Company Limited
Consolidated Statements of Changes in Shareholders' Equity
(presented in US$ thousands)

	Notes	Share capital	Share premium	Unpaid capital	Cumulative Translation Adjustment	Retained earnings (accumulated deficit)	Equity attributable to Shareholders of Urals Energy Public Company Limited	Minority interest	Total equity
Balance at 31 December 2003		20	10	-	-	(669)	(639)	-	(639)
Effect of currency translation					1,264	-	1,264	1	1,265
Loss for the year					-	(3,672)	(3,672)	14	(3,658)
Total recognized income (loss)					1,264	(3,672)	(2,408)	15	(2,393)
Acquisitions		-	-	-	-	-	-	1,312	1,312
Issuance of shares	12	189	41,291	(11,324)	-	-	30,156	-	30,156
Contribution from shareholders	12	-	871	-	-	-	871	-	871
Balance at 31 December 2004		209	42,172	(11,324)	1,264	(4,341)	27,980	1,327	29,307
Effect of currency translation					(3,560)	-	(3,560)	(46)	(3,606)
Profit for the year					-	7,055	7,055	(82)	6,973
Total recognized income (loss)					(3,560)	7,055	3,495	(128)	3,367
Acquisitions		-	-	-	-	-	-	-	
Issuance of shares	12	251	159,141	11,324	-	-	170,716	-	170,716
Share-based payment	12	-	42	-	-	-	42	-	42
Balance at 31 December 2005		460	201,355	-	(2,296)	2,714	202,233	1,199	203,432

1 Activities

Urals Energy Public Company Limited ("Urals Energy" or the "Company") was incorporated as a limited liability company in Cyprus on 10 November 2003. The Company was formed to act as a holding company for investments in the Russian oil and gas exploration and production sector. Pursuant to a Shareholder Agreement dated 28 July 2004, certain shareholders contributed certain assets including AO Cheptskoye NGDU to the Company, (Notes 4 and 12).

Urals Energy and its subsidiaries (the "Group") are primarily engaged in oil and gas exploration and production in the Russian Federation and processing of crude oil for distribution on both the Russian and international markets.

The registered office of Urals Energy is at 31 Evagorou Avenue, Suite 34, CY-1066, Nicosia, Cyprus. In July 2005, the Company changed its name to Urals Energy Public Company Limited. The Group's primary office in Russia is located at 6 Oktyabrskaya Ul. Moscow, 127018, Russian Federation.

The Group comprises the following subsidiaries:

		Effective interest at 31 December:	
Entity	**Jurisdiction**	**2005**	**2004**
Exploration and production			
ZAO Petrosakh ("Petrosakh")	Sakhalin	97.2%	97.2%
ZAO Arcticneft ("Arcticneft")	Nenetsky	100.0%	-
OOO CNPSEI ("CNPSEI")	Komi	100.0%	100.0%
ZAO Chepetskoye NGDU ("Chepetskoye")	Udmurtia	100.0%	100.0%
OOO Dinyu ("Dinyu")	Komi	100.0%	-
OOO Michayuneft ("Michayuneft")	Komi	100.0%	-
Management company			
OOO Urals Energy	Moscow	100.0%	100.0%
Service company			
Urals Energy (UK) Limited	United Kingdom	100.0%	100.0%
Exploration			
OOO Urals-Nord ("Urals-Nord")*	Nenetsky	100.0%	50.0%
Trading			
UENEXCO Limited ("UENEXCO")**	Cyprus	100.0%	-

** Urals-Nord was an equity associate of the Group at 31 December 2004.*

** UENEXCO was incorporated during 2005 for trading purposes.

2 Basis of Preparation of the Financial Statements and Significant Accounting Policies

Basis of preparation. These consolidated financial statements have been prepared in accordance with, and comply with, International Financial Reporting Standards ("IFRS"). The consolidated financial statements have been prepared under the historical cost convention. The preparation of consolidated financial statements in conformity with IFRS requires management to make prudent estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements preparation and the reported amounts of revenues and expenses during the reporting period. Critical estimates are disclosed in Note 3. Actual results could differ from the estimates.

Functional and presentation currency. The United States Dollar ("US dollar or US$") is the presentation currency for the Group's operations as the majority of the Company's operations is conducted in US dollars and management have used the US dollar accounts to manage the Group's financial risks and exposures, and to measure its performance. Financial statements of the Russian subsidiaries are measured in Russian Roubles and presented in US dollars in accordance with IAS 21 (revised 2003), The Effects of Changes in Foreign Exchange Rates.

Translation to functional currency. Monetary balance sheet items denominated in foreign currencies have been remeasured using the exchange rate at the respective balance sheet date. Exchange gains and losses resulting from foreign currency translation are included in the determination of profit or loss. The US dollar to Russian Rouble exchange rates were 28.78 and 27.75 as of 31 December 2005 and 2004, respectively.

Translation to presentation currency. The results and financial position of each group entity (functional currency of none of which is a currency of a hyperinflationary economy) are translated into the presentation currency as follows:

(i) Assets and liabilities for each balance sheet presented are translated at the closing rate at the date of that balance sheet. Goodwill and fair value adjustments arising on the acquisitions are treated as assets and liabilities of the acquired entity.

(ii) Income and expenses for each income statement are translated at average exchange rates (unless this average is not a reasonable approximation of the cumulative effect of the rates prevailing on the transaction dates, in which case income and expenses are translated at the dates of the transactions).

(iii) All resulting exchange differences are recognised as a separate component of equity.

When a subsidiary is disposed of through sale, liquidation, repayment of share capital or abandonment of all, or part of, that entity, the exchange differences deferred in equity are reclassified to profit or loss.

Group accounting. Subsidiaries, which are those entities in which the Group has an interest of more than one half of the voting rights, or otherwise has power to exercise control over the operations, are consolidated. Subsidiaries are consolidated from the date on which control is transferred to the Group and are no longer consolidated from the date that control ceases. The purchase method of accounting is used to account for the acquisition of subsidiaries by the Group. The cost of an acquisition is measured as the fair value of the consideration provided or liabilities incurred or assumed at the date of exchange plus costs directly attributable to the acquisition.

All intercompany transactions, balances and unrealised gains on transactions between group companies are eliminated; unrealised losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

Minority interest at the balance sheet date represents the minority shareholders' portion of the fair values of the identifiable assets, liabilities and contingent liabilities of the subsidiary at the acquisition date, and the minorities' portion of movements in equity since the date of the combination. Minority interest is presented as a separate component of equity. Where the losses applicable to the minority in a consolidated subsidiary exceed the minority interest in the equity of the subsidiary, the excess and any further losses applicable to the minority are charged against the majority interest except to the extent that the minority has a binding obligation to, and is able to, make good the losses. If the subsidiary subsequently reports profits, the majority interest is allocated all such profits until the minority's share of losses previously absorbed by the majority has been recovered.

Property, plant and equipment. Property, plant and equipment acquired as part of a business combination is recorded at fair value at the acquisition date. All subsequent additions are recorded at historical cost of acquisition or construction and adjusted for accumulated depreciation, depletion and impairment. Oil and gas exploration and production activities are accounted for in accordance with the successful efforts method. Under the successful efforts method, costs of successful development and exploratory wells are capitalised. Costs of unsuccessful exploratory wells are expensed upon determination that the well does not justify commercial development. Other exploration costs are expensed as incurred.

Depletion of capitalized costs of proved oil and gas properties is calculated using the units-of-production method for each field based upon proved reserves for property acquisitions and proved developed reserves for exploration and development costs. Oil and gas reserves for this purpose are determined in accordance with Society of Petroleum Engineers definitions and were estimated by DeGolyer and MacNaughton, the Group's independent reservoir engineers. Gains or losses from retirements or sales of oil and gas properties are included in the determination of profit for the year.

Depreciation of non oil and gas property, plant and equipment is calculated using the straight-line method over their estimated remaining useful lives, as follows:

	Estimated useful life
Refinery and related equipment	19
Buildings	20
Other assets	6 to 20

Provisions. Provisions are recognised when the Group has a present legal or constructive obligation as a result of past events and when it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made.

Provisions, including those related to dismantlement, abandonment and site restoration, are evaluated and re-estimated annually, and are included in the financial statements at each balance sheet date at their expected net present values using discount rates which reflect the economic environment in which the Group operates.

Changes in provisions resulting from the passage of time are reflected in the statement of income each year under financial items. Other changes in provisions, relating to a change in the expected pattern of settlement of the obligation, changes in the discount rate or in the estimated amount of the obligation, are treated as a change in accounting estimate in the period of the change.

The provision for dismantlement liability is recorded on the balance sheet, with a corresponding amount being recorded as part of property, plant and equipment in accordance with IAS 16.

Leases. Leases of property, plant and equipment where the Group has substantially all the risks and rewards of ownership are classified as finance leases. Finance leases are capitalised at the commencement of the lease at the lower of the fair value of the leased property or the present value of the minimum lease payments. Each lease payment is allocated between the liability and finance charges so as to achieve a constant rate on the finance balance outstanding. The corresponding rental obligations, net of finance charges, are included in other long-term payables. The interest element of the finance cost is charged to the income statement over the lease period. The property, plant and equipment acquired under finance leases are depreciated over the shorter of the useful life of the asset or the lease term, with the comparison being made based on the current annual extraction level.

Leases in which a significant portion of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to the income statement on a straight-line basis over the period of the lease.

Impairment of assets. Assets that are subject to depreciation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell or value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows (cash-generating units).

Inventories. Inventories of extracted crude oil, materials and supplies and construction equipment are valued at the lower of the weighted-average cost and net realisable value. General and administrative expenditure is excluded from inventory costs and expensed in the period incurred.

Trade receivables. Trade receivables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method, net of provision for impairment. A provision for impairment of trade receivables is established when there is objective evidence that the Group will not be able to collect all amounts due according to the original terms of receivables. The amount of the provision is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the effective interest rate. The amount of the provision is recognised in the statement of operations.

Cash and cash equivalents. Cash and cash equivalents include cash in hand and deposits held at call with banks. Cash and cash equivalents are carried at amortised cost using the effective interest method.

Value added tax. Value added taxes related to sales are payable to tax authorities upon collection of receivables from customers. Input VAT is reclaimable against sales VAT upon payment for purchases. The tax authorities permit the settlement of VAT on a net basis. VAT related to sales and purchases which have not been settled at the balance sheet date (VAT deferred) is recognised in the balance sheet on a gross basis and disclosed separately as a current asset and liability. Where provision has been made against debtors deemed to be uncollectible, an impairment loss is recorded for the gross amount of the debtor, including VAT. The related VAT deferred liability is maintained until the debtor is written off for statutory accounting purposes.

Borrowings. Borrowings are recognised initially at the fair value of the liability, net of transaction costs incurred. In subsequent periods, borrowings are stated at amortised cost using the effective yield method; any difference between amount at initial recognition and the redemption amount is recognised as interest expense over the period of the borrowings. Borrowings are classified as current liabilities unless the Group has an unconditional right to defer settlement of the liability for at least 12 months after the balance sheet date.

Loans receivable. The loans advanced by the Group to its shareholder are classified as "loans and receivables" in accordance with IAS 39 and stated at amortised cost using the effective interest method.

Deferred income taxes. Deferred income tax is calculated at rates enacted or substantially enacted at the balance sheet date, using the balance sheet liability method, for all temporary differences between the tax bases of assets and liabilities and their carrying values for financial reporting purposes. The principal temporary differences arise from depreciation on property, plant and equipment, provisions, fair value adjustments to long-term items, and expenses which are charged to the statement of operations before they become deductible for tax purposes.

Deferred income tax assets attributable to deducible temporary differences, unused tax losses and credits are recognised only to the extent that it is probable that future taxable profit or taxable temporary differences will be available against which they can be utilised.

Deferred income tax assets and liabilities are offset when the Group has a legally enforceable right to set off current tax assets against current tax liabilities, when deferred tax balances relate to the same regulatory body, and when they relate to the same taxable entity.

Social costs. The Group incurs employee costs related to the provision of benefits such as health insurance. These amounts principally represent an implicit cost of employing production workers and, accordingly, have been charged to statement of operations.

Pension costs. The Group makes required contributions to the Russian Federation state pension scheme on behalf of its employees. Mandatory contributions to the governmental pension scheme are expensed or capitalized to inventories on a basis consistent with the associated salaries and wages.

Revenue recognition. Revenues are recognised when crude oil or refined products are dispatched to customers and title has transferred. Revenues from non-cash sales are recognised at the fair value of the goods or services received. Gross revenues include export duties and excise taxes but exclude value added taxes.

Segments. The Group operates in one business segment which is crude oil exploration and production. The Group assesses its results of operations and makes its strategic and investment decisions based on the analysis of its profitability as a whole. The Group operates within one geographic segment, which is the Russian Federation.

Reclassifications. Certain reclassifications have been made to 2004 amounts to conform to 2005 presentation. Additionally, certain adjustments were made to 2004 amounts related to the finalization of the Group's purchase accounting for 2004 acquisitions. The table below discloses the adjusted amounts before and after the reclassifications.

Management believes that the current presentation is preferable to that presented in prior years.

	As originally reported	Following reclassification
At 31 December 2004		
Inventories	2,247	2,773
Property, plant and equipment	100,622	102,754
Short-term borrowings and current portion of long-term		38,486
borrowings	38,815	
Accounts payable and accrued expenses	3,019	3,748
Deferred tax liability	17,751	18,390
Other long-term liabilities	-	1,590
Translation difference	1,236	1,264
For the year ended 31 December 2004		
Selling, general and administrative expenses	7,115	6,825
Cost of production	4,062	4,352

At 31 December 2004, inventories, property, plant and equipment, accounts payable and accrued expenses, deferred tax liability, other long-term liabilities and translation difference were increased by \$0.526 million, \$2.132 million, \$0.400 million, \$0.639 million, \$1.590 million and \$0.028 million, respectively, to reflect the respective fair values after the Group completed its purchase accounting for its acquisition of Petrosakh that occurred in December 2004.

Also at 31 December 2004, management reclassified \$0.329 million from short-term borrowings and current portion of long-term debt to accounts payable and accrued expenses to conform to current year's presentation of accrued interest and certain other accruals.

For the year ended 31 December 2004, selling, general and administrative expenses was decreased and cost of production was increased by \$0.290 million, primarily to record salaries of management personnel working at production locations within cost of production.

New accounting developments. In December 2003, the International Accounting Standards Board ("IASB") released 15 revised International Accounting Standards and withdrew one IAS standard. The revised standards were all mandatory for periods starting on or after 1 January 2005.

In 2004, the IASB published five new standards, two revisions and two amendments to existing standards. In 2005, the IASB published one new standard and seven amendments of existing standards. In addition, the International Financial Reporting Interpretations Committee issued five new interpretations in 2004 and two in 2005.

Significant changes relevant to the Group as a result of the new effective or early adopted IFRSs are:

IAS 1 (revised 2003), Presentation of Financial Statements ("IAS 1 (revised)"). IAS 1 (revised) requires the classification as current all financial liabilities for which the Group does not have an unconditional right to defer their settlement for at least twelve months after the balance sheet date. Additionally, IAS 1 (revised) requires that minority interest be presented within total equity and that profit or loss for the period is allocated between "profit or loss attributable to minority interest" and "profit or loss attributable to shareholders of the parent" on the face of the consolidated statements of operations. The revised standard is applied retrospectively in accordance with IAS 8.

IAS 8 (revised 2003), Accounting Policies, Changes in Accounting Estimates and Errors. The Group now applies all voluntary changes in accounting policies retrospectively. Comparatives are amended in accordance with the new policies. All material errors are now corrected retrospectively in the first set of financial statements after their discovery.

IAS 21 (revised 2003) The Effects of Changes in Foreign Exchange Rates ("IAS 21 (revised)"). IAS 21 (revised) clarifies the method of translation of foreign currencies to the functional and presentation currency and clarifies that goodwill and fair value adjustments to assets and liabilities resulting from acquisitions are treated as part of the assets and liabilities of the acquired entity and translated at the exchange rate on the balance sheet date. There was no significant effect upon the Group's retrospective adoption of IAS 21 (revised) on 1 January 2005.

IAS 24 (revised 2003) Related Party Disclosures. The definition of related parties was extended and additional disclosures required by the revised standard were made in these financial statements. The revised standard is applied retrospectively in accordance with IAS 8.

IAS 36 (revised 2004) Impairment of Assets ("IAS 36"). The Group now performs impairment tests of goodwill, intangible asset not yet available for use and intangible assets with indefinite useful life at least annually. The 'bottom-up/top-down' approach to testing goodwill was replaced by a simpler method. As applicable, the goodwill is, from the acquisition date, allocated to each of the acquirer's cash-generating units ("CGU"), or groups of CGUs, that are expected to benefit from the synergies of the business combination. Each unit or group of units to which the goodwill is allocated represents the lowest level at which the goodwill is monitored and is not larger than a segment. Reversals of impairment losses of goodwill are now prohibited. The clarifications of certain elements of value in use calculations in the revised IAS 36 did not have an impact on these financial statements. Management now assesses reasonableness of the assumptions on which the Group's current cash flow projections are based by examining the causes of differences between past cash flow projections and actual cash flows. The revised IAS 36 is applied in accordance with the standard's transitional provisions to goodwill and intangible assets acquired in business combinations for which the agreement date is on or after 31 March 2004 and to all other assets prospectively from 1 January 2005.

IAS 38 (revised 2004) Intangible Assets ("IAS 38"). The revised IAS 38 is applied prospectively in accordance with its transitional provisions. The amended accounting policies apply to intangible assets acquired in business combinations for which the agreement date is on or after 31 March 2004 and to all other intangible assets acquired on or after 1 January 2005. Intangible assets now include assets that arise from contractual or other legal rights, regardless of whether those rights are transferable or separable. The probability of inflow of economic benefits recognition criterion is now deemed to be always met for intangibles that are acquired separately or in a business combination. The Group's policies were amended to introduce the concept of indefinite life intangible assets which exist when, based on an analysis of all of the relevant factors, management concludes that there is no foreseeable limit to the period over which the asset is expected to generate net cash inflows. Such intangibles are not amortised but tested for impairment at least annually. The Group has reassessed the useful lives of its intangible assets in accordance with the transitional provisions of IAS 38. No adjustment resulted from this reassessment.

IFRS 2, Share-based Payment. IFRS 2 requires that the fair value of the employee services received in exchange for the grant of the equity instruments is recognised as an expense over the vesting period. For transactions with parties other than employees, the Group accounts for the transaction based upon the fair value of goods or services provided, unless the fair values are not reliably estimable. The adoption of IFRS 2 on 1 January 2005 did not have a material effect on the Group as the Group had no outstanding share-based awards upon adoption.

IFRS 3, Business Combinations. IFRS 3 requires accounting for all business combinations by applying the purchase method and separate recognition, at the acquisition date, of the acquiree's contingent liabilities if their fair values can be measured reliably. It also requires that the identifiable assets, liabilities and contingent liabilities are measured at their fair values irrespective of the extent of any minority interest. Any resulting goodwill is tested for impairment annually, or when there are indications of impairment. The excess of the Group's interest in the net fair value of an acquiree's identifiable assets, liabilities and contingent liabilities over the cost ("negative goodwill") is recognized immediately in the consolidated statement of operations. The Group applies transitional provisions of IFRS 3 and applies it to all business combinations for which the agreement date is on or after 31 March 2004.

IFRS 5 (issued 2005) Non-current Assets Held for Sale and Discontinued Operations ("IFRS 5"). The Group applies IFRS 5 prospectively in accordance with its transitional provisions to non-current assets (or disposal groups) that meet the criteria to be classified as 'held for sale' and operations that meet the criteria to be classified as 'discontinued' after 1 January 2005. The Group's accounting policies now describe assets 'held for sale' as those that will be recovered principally through a sale transaction rather than through continuing use. Subject to certain exceptions, assets or disposal groups that are classified as 'held for sale' are measured at the lower of carrying amount and fair value less costs to sell. Such assets cease to be depreciated and are presented separately on the face of the balance sheet. There was no impact of the adoption of IFRS 5.

IFRS 6, Exploration for and Evaluation of Mineral Resources ("IFRS 6"). IFRS 6 was early adopted by the Group, before its effective date. IFRS 6 allows an entity to continue using the accounting policies for exploration and evaluation assets applied immediately before adopting the IFRS, subject to certain impairment test requirements. As permitted under IFRS 6, the Group capitalizes exploration and evaluation costs until such time as the economic viability of producing the underlying resources is determined.

IAS 21 (Amendment) - Net Investment in a Foreign Operation. The amendment to IAS 21 was early adopted by the Group, before its effective date. It clarifies treatment of foreign exchange differences on intercompany loans that form part of a net investment in a foreign operation.

The adoption of all the other new or revised standards that are effective for 2005 did not have a material impact on the Group's financial position, statements of income or of cash flows.

New or revised standards that are not yet effective. Certain new standards and interpretations have been published that are mandatory for the Group's accounting periods beginning on or after 1 January 2006 or later periods and which the Group has not early adopted:

IFRIC 4, Determining whether an Arrangement contains a Lease (effective from 1 January 2006); *IAS 39 (Amendment) – The Fair Value Option* (effective from 1 January 2006); *IAS 39 (Amendment) - Cash Flow Hedge Accounting of Forecast Intragroup Transactions* (effective from 1 January 2006); *IAS 39 (Amendment) – Financial Guarantee Contracts* (effective from 1 January 2006); *IFRS 7, Financial Instruments: Disclosures and a Complementary Amendment to IAS 1 Presentation of Financial Statements - Capital Disclosures* (effective from 1 January 2007); *IAS 19 (Amendment) - Employee Benefits* (effective from 1 January 2006); *IFRS 1 (Amendment) - First-time Adoption of International Financial Reporting Standards and IFRS 6 (Amendment) - Exploration for and Evaluation of Mineral Resources* (effective from 1 January 2006); *IFRIC 5, Rights to Interests arising from Decommissioning, Restoration and Environmental Rehabilitation Funds* (effective from 1 January 2006); *IFRIC 6, Liabilities arising from Participating in a Specific Market - Waste Electrical and Electronic Equipment* (effective for periods beginning on or after 1 December 2005); *IFRIC 7, Applying the Restatement Approach under IAS 29* (effective for periods beginning on or after 1 March 2006); *IFRIC 8, Scope of IFRS 2* (effective for periods beginning on or after 1 May 2006) and *IFRIC 9, Reassessment of Embedded Derivatives* (effective for periods beginning on or after 1 June 2006).

3 Critical Estimates in Applying Accounting Policies

These new standards and interpretations are not expected to significantly affect the Group's financial statements when adopted on 1 January 2006 or later.

The Group makes estimates and assumptions that affect the reported amounts of assets and liabilities. Estimates and judgements are continually evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Management also makes certain judgements, apart from those involving estimations, in the process of applying the accounting policies. Judgments that have the most significant effect on the amounts recognised in the financial statements and estimates that can cause a significant adjustment to the carrying amount of assets and liabilities are outlined below.

Accounting for extractive industry activity. The Group follows the successful efforts method of accounting for oil and gas properties. Under the successful efforts method, property acquisitions, successful exploratory wells, all development costs and support equipment and facilities are capitalised. Unsuccessful exploratory wells are charged to expense at the time the wells are determined to be non-productive. Production costs, overhead and all exploration costs other than exploratory drilling are charged to expense as incurred. Acquisition costs of unproved properties, exploration and evaluation costs are evaluated periodically and any impairment assessed is charged to expense.

The Group calculates depreciation, depletion and amortisation of capitalised costs of oil and gas properties using the unit-of-production method for each field based upon proved developed reserves for exploration and development costs, and total proved reserves for acquisitions of proved properties. For this purpose, the oil and gas reserves of key fields have been determined based on estimates of mineral reserves determined in accordance with internationally recognised definitions and independently assessed by internationally recognised petroleum engineers. The present value of the estimated costs of dismantling oil and gas production facilities, including abandonment and site restoration costs are recognised when the obligation is incurred and are included within the carrying value of property, plant and equipment, and therefore subject to amortisation thereon using the unit-of-production method. Changes in estimates of reserves can result in significant changes in depletion expense.

Tax legislation. Russian tax, currency and customs legislation is subject to varying interpretations as further discussed in Note 17.

Deferred income tax asset recognition. Deferred tax assets represent income taxes recoverable through future deductions from taxable profits. Deferred income tax assets are recorded on the Group's consolidated balance sheets to the extent that realisation of the related tax benefits is probable. In determining future taxable profits and the amount of tax benefits that are probable in the future, management makes judgements and applies estimation based on recent years' taxable profits and expectations of future taxable income.

Related party transactions. In the normal course of business, the Group enters into transactions with its related parties. Judgement is applied in determining if transactions are priced at market or non-market interest rates, where there is no active market for such transactions. The basis for judgement is pricing for similar types of transactions with unrelated parties and effective interest rate analyses.

Assumptions to determine amount of provisions. In determining amounts of provisions, management uses all information available to determine whether an asset is recoverable or whether it is probable that an event will result in outflows of resources from the Group. Significant judgment is used to estimate the amounts of provisions, including such factors as the current overall economic conditions, specific customer, counterparty or industry conditions and the current overall legal and tax environment. Changes in any of these conditions may result in adjustments to provisions recorded by the Group.

Useful lives of property, plant and equipment. Items of property, plant and equipment are stated at cost less accumulated depreciation. The estimation of the useful life of an item of property, plant and equipment is a matter of management judgment based upon experience with similar assets. In determining the useful life of an asset, management considers the expected usage, estimated technical obsolescence, physical wear and tear and the physical environment in which the asset is operated. Changes in any of these conditions or estimates may result in adjustments to future depreciation rates.

Fair values of acquired assets and liabilities. Since its inception, the Group has completed several significant acquisitions (Note 4). IFRS 3 requires that, at the date of acquisition, all identifiable assets (including intangible assets), liabilities and contingent liabilities of an acquired entity be recorded at their respective fair values. The estimation of fair values requires management judgment. For significant acquisitions, management engages independent experts to advise as to the fair values of acquired assets and liabilities. Changes in any of the estimates subsequent to the finalization of acquisition accounting may result in losses in future periods.

Going concern. Management assumed that the Group will continue as a going concern.

Fair values of financial instruments. Fair value is the amount at which a financial instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation, and is best evidenced by an active quoted market price. The estimated fair values of financial instruments have been determined by the Group using available market information, where it exists, and appropriate valuation methodologies where no market information is available. However, judgement is necessarily required to interpret market data to determine the estimated fair value.

Cash and cash equivalents are carried at amortised cost which approximates current fair value.

At 31 December 2005 and 2004, the carrying amounts of trade and other receivables, short-term borrowings, trade and other payables, taxes payable and advances from customers approximated their fair values.

The fair values of the Group's long-term borrowings were estimated based upon rates available to the Group on similar instruments of similar maturities. At 31 December 2005 and 2004, management believes that the fair values of its borrowings approximate their respective carrying values.

4 Acquisitions

Acquisition of Dinyu. In November 2005, the Group acquired a 100.0 percent stake in Dinyu from Lonsdacks Investments Limited for $61.5 million following the approval from the Russian Federal Antimonopoly Service.

Subsequent to its purchase of Dinyu, on 21 December 2005 the Group purchased the 35 percent stake owned by third parties in the 65 percent-owned subsidiary of Dinyu, OOO Michayuneft ("Michayuneft") for $0.2 million. Since the date of acquisition, Dinyu contributed $0.466 million of net profit to the Group's operating results.

Acquisition of Arcticneft. In July 2005, the Group acquired a 100.0 percent equity interest in Arcticneft from OAO LUKoil for $23 million net of debt. Arcticneft holds production licenses in the Nenetsky Autonomous Region of the Russian Federation. Since the date of acquisition, Arcticneft contributed $0.320 million of net loss to the Group's operating results.

Management's purchase accounting allocation resulted in an excess of $16.8 million of net identifiable assets and oil and gas properties and equipment over the purchase price. Management believes that this amount is attributed to the seller's undervaluing of Arcticneft and its desire to dispose of non-core assets. The associated gain was recorded in the Group's consolidated statement of operations for the year ended 31 December 2005.

Acquisition of Urals-Nord. In April 2005, the Company acquired the remaining 50.0 percent interest in OOO Urals Nord ("Urals Nord") for $14 million. On that date $1.5 million was paid immediately in cash and $12.5 million was paid in October 2005. The Group incurred $0.84 million of additional cost related to seismic review of the license areas. Urals Nord holds 5 exploration licenses for Beluginisky, Zapadno-Sorokinskiy, Fakelniy, Nadezhdinskiy and Alfinskiy Prospects. Urals-Nord has been consolidated from the date of acquisition. Management believes that the purchase price for Urals-Nord approximates the fair value of unproved oil and gas properties acquired. Such unproved oil and gas properties are included within property, plant and equipment in the consolidated balance sheet. No goodwill was recognized in the acquisition. Since the date of acquisition, Urals-Nord contributed $0.035 million of net loss to the Group's operating results.

Fair values of acquired companies. The table below discloses the carrying values and fair values of the assets and liabilities of the companies acquired during 2005 immediately prior to and upon acquisition, respectively. The values disclosed below comprise 100 percent of the assets and liabilities of the acquirees. The IFRS carrying values before the acquisition reported below relate to the IFRS carrying values in the separate accounts of the acquirees. Such stakes were revalued to their fair values at the acquisition date for purposes of these consolidated financial statements.

	Urals-Nord		Arcticneft,		Dinyu, including Michayuneft	
	IFRS carrying amounts before acquisition	Fair values at acquisition	IFRS carrying amounts before acquisition	Fair values at acquisition	IFRS carrying amounts before acquisition	Fair values at acquisition
Cash and cash equivalents	-	-	2,045	2,045	122	122
Accounts receivable and prepayments	-	-	1,719	1,719	4,224	4,224
Other current assets	-	-	8,350	12,583	1,243	1,243
Oil and gas properties and equipment	840	19,261	34,073	74,040	15,460	86,466
Other non-current assets	-	-	188	188	857	857
Short-term borrowings and current portion of long-term borrowings	840	840	13,036	13,036	8,653	8,563
Other current liabilities	-	-	20,425	20,425	5,574	5,574
Deferred income tax liability, non-current	-	4,421	5,934	16,503	-	17,041
Other non-current liabilities	-	-	784	784	-	-

Summary combined financial information. The following table sets forth summary combined financial information for the year ended 31 December 2005 that is presented to provide information to evaluate the financial effects of the acquisitions of Arcticneft, Dinyu and Urals-Nord as if they had occurred on 1 January 2005.

	Group results	Urals-Nord	Arcticneft	Dinyu	Adjustments and eliminations	Summary combined
Total revenues	92,918	-	22,154	31,831	(27,507)	119,396
Profit (loss) for the period	7,055	(35)	(1,082)	2,354	(669)	7,623

The summary combined financial information should not be construed to represent consolidated financial information. Group results include the activities of the acquired entities from the respective acquisition dates through 31 December 2005. Total revenues and profit (loss) for the period for Urals-Nord, Arcticneft and Dinyu comprise the respective entities' results for the full year, including the period prior to acquisition, without adjustments for intercompany transactions or fair values. Adjustments and eliminations include the following: (a) depreciation, depletion and amortization was adjusted to reflect the higher carrying values of property, plant and equipment following fair value adjustments; (b) intercompany eliminations were recorded; (c) adjustments to eliminate results of the period included both in the Group results and the respective entities' results for the full year; and (d) corresponding adjustments for income taxes were recorded. However, no adjustments were made to adjust interest expense for borrowings used to finance these acquisitions.

Acquisition of Petrosakh. In December 2004, the Group acquired a 97.2 percent equity interest in Petrosakh for $46.9 million. Petrosakh is an integrated oil and gas exploration and production company located on Sakhalin Island in the Russian Far East. Petrosakh operates the Okruzhnoye and Pogranichnoye onshore oil fields licenses and has an exploration license for the off-shore part of the Pogranichnoye field. No goodwill was recognized on the acquisition of Petrosakh.

Acquisition of CNPSEI. In November 2004, the Group acquired a 100.0 percent equity interest in CNPSEI for $6.8 million. CNPSEI is an oil and gas exploration and production company located in the Komi region of northern Russia. CNPSEI operates the Sosnovskoye and Yuzhnotebukskoye onshore oil field licenses. No goodwill was recognized on the acquisition of CNPSEI.

Acquisition of Chepetskoye. In October 2004, the Group acquired a 100.0 percent interest in Chepetskoye, from one if its principal shareholders for nominal consideration. Chepetskoye is an oil and gas exploration and production company located in the Udmurtia region of the Russian Federation. Chepetskoye operates the Zapadno-Krasnogorsky onshore oil field licenses.

This acquisition was contemplated as part of the Urals Energy Shareholder Agreement dated 28 July 2004, whereby shareholders would contribute cash or assets for their equity interests in Urals Energy (Note 12). Chepetskoye was recognised initially at its fair value of $5.9 million.

Fair values of acquired companies. The table below discloses the carrying values and fair values of the assets and liabilities of the companies acquired during 2004 immediately prior to and upon acquisition, respectively. The values disclosed below comprise 100.0 percent of the assets and liabilities of the acquirees. The IFRS carrying values before the acquisition reported below relate to the IFRS carrying values in the separate accounts of the acquirees. Such stakes were revalued to their fair values at the acquisition date for purposes of these consolidated financial statements.

	Petrosakh		CNPSEI		Chepetskoye	
	IFRS carrying amounts before acquisition	Fair values at acquisition	IFRS carrying amounts before acquisition	Fair values at acquisition	IFRS carrying amounts before acquisition	Fair values at acquisition
Cash and cash equivalents	373	373	1	1	158	158
Other current assets	2,540	3,776	1,016	1,016	654	654
Properties, plant and equipment (excluding oil and gas properties)	16,517	13,220	1,520	1,520	401	401
Oil and gas properties	6,439	60,698	3,264	7,886	7,529	15,768
Other non-current assets	59	59	-	-	-	-
Short-term borrowings and current portion of long-term borrowings	10,478	10,478	-	-	8,650	8,650
Other current liabilities	2,327	2,266	2,101	2,101	266	266
Deferred income tax liability, non-current	2,559	14,915	270	1,417	31	2,008
Other non-current liabilities	2,205	2,205	105	105	155	155

Had these acquisitions been completed on 1 January 2004, consolidated revenues and net loss would have been $33.7 million and $3.0 million, respectively, for the year ended 31 December 2004.

5 Accounts receivable and prepayments

	31 December:	
	2005	2004
Accounts and notes receivable – trade ($0.586 million and $0.608 million provision for impairment at 31 December 2005 and 2004)	7,871	70
Prepaid taxes, other than value added tax	4,408	410
Advances to suppliers	3,871	453
Recoverable taxes including VAT	3,503	1,720
Receivables from related parties (Note 19)	2,725	723
Other	1,410	330
Total accounts receivable and prepayments	23,788	3,706

6 Inventories

	31 December: 2005	2004
Crude oil	3,252	1,184
Petroleum products	1,590	592
Materials and supplies	7,799	997
Total inventories	**12,641**	**2,773**

7 Property, Plant and Equipment

Activity within property, plant and equipment for the two years ended 31 December 2005 is detailed below.

	Oil and gas properties	Refinery and related equipment	Buildings	Other Assets	Assets under construction	Total
Cost						
Balance at 31 December 2003	-	-	-	-	-	-
Translation difference	1,933	124	14	57	50	2,178
Business combinations	84,876	8,560	975	3,582	1,770	99,763
Additions	-	-	-	133	1,217	1,350
Transfers	579	-	-	-	(579)	-
Balance at 31 December 2004	87,388	8,684	989	3,772	2,458	103,291
Translation difference	(5,129)	(315)	(41)	(154)	(219)	(5,858)
Business combinations	172,110	615	1,100	650	5,405	179,880
Additions	4,697	-	-	209	16,452	21,358
Transfers	8,053	-	-	964	(9,017)	-
Changes in estimates of dismantlement provision	(765)	-	-	-	-	(765)
Disposals	(217)	-	-	(310)	(325)	(852)
Balance at 31 December 2005	266,137	8,984	2,048	5,131	14,754	297,054

	Oil and gas properties	Refinery and related equipment	Buildings	Other Assets	Assets under construction	Total
Accumulated Depreciation						
Balance at 31 December 2003	-	-	-	-	-	-
Translation difference	(14)	-	-	(1)	-	(15)
Depreciation, depletion and amortization	(505)	-	-	(17)	-	(522)
Balance at 31 December 2004	(519)	-	-	(18)	-	(537)
Translation difference	128	8	4	10	-	150
Depreciation, depletion and amortization	(8,044)	(510)	(226)	(614)	-	(9,394)
Disposals	118	-	-	94	-	212
Balance at 31 December 2005	(8,317)	(502)	(222)	(528)	-	(9,569)
Net Book Value						
Balance at 31 December 2004	86,869	8,684	989	3,754	2,458	102,754
Balance at 31 December 2005	257,820	8,482	1,826	4,603	14,754	287,485

Included within oil and gas properties at 31 December 2005 and 2004 were exploration and evaluation assets of $140.5 million and $37.5 million, respectively, including property acquisition costs with net book values of $134.0 million and $37.5 million, respectively, not subject to depletion. Additionally, included within oil and gas properties at 31 December 2005 and 2004 were property acquisition costs with net book value of $41.6 million and $12.8 million, respectively, that were being depleted over total proved reserves.

The Group's oil fields are situated in the Russian Federation on land owned by the Russian government. The Group holds licenses and associated mining plots and pays production taxes to extract oil and gas from the fields. The licenses expire between 2008 and 2067, but may be extended. Management intends to renew the licences as the properties are expected to remain productive subsequent to the license expiration date.

Estimated costs of dismantling oil and gas production facilities, including abandonment and site restoration costs, amounting to $0.020 million and $0.198 million at 31 December 2005 and 2004, respectively, are included in the cost of oil and gas properties. The Group has estimated its liability based on current environmental legislation using estimated costs when the expenses are expected to be incurred.

At 31 December 2005 and 2004, property, plant and equipment with carrying net book value of $90.2 million and $1.6 million, respectively, was pledged as collateral for the Group's borrowings.

8 Accounts Payable and Accrued Expenses

	31 December:	
	2005	**2004**
Trade payables	2,809	236
Interest payable	833	224
Wages and salaries	806	278
Advances from and payables to related parties (Note 19)	77	861
Payable under guarantee arrangements (Note 19)	-	1,073
Other payable and accrued expenses	3,407	1,076
Total accounts payable and accrued expenses	7,932	3,748

Of interest payable, $0.117 million was payable to related parties at 31 December 2004.

9 Taxes

Income taxes for the periods ended 31 December 2005 and 2004 comprised the following:

	Year ended 31 December:	
	2005	**2004**
Current tax expense	890	103
Deferred tax charge (benefit)	(3,155)	(280)
Income tax charge (benefit)	(2,265)	(177)

Below is a reconciliation of profit (loss) before taxation to income tax charge (benefit):

	Year ended 31 December:	
	2005	**2004**
Profit (loss) before income tax	4,708	(3,835)
Theoretical tax charge (benefit) at the statutory rate of 24 percent	1,130	(920)
Excess of net assets acquired over purchase price	(4,030)	-
Non-recurring mobilization costs	1,721	-
Losses utilized in the current year	(1,340)	-
Tax credits related to seismic surveys	(1,047)	-
Expenses at other tax rates	939	-
Other income not assessable for income tax purposes	-	(10)
Other expenses and losses not deductible for income tax purposes	334	748
Effect of tax penalties	28	5
Income tax charge (benefit)	(2,265)	(177)

The movement in deferred tax assets and liabilities during the year ended 31 December 2005 was as follows:

	2005	Recognized in equity for translation differences	Charged (credited) to the statement of operations	Effect of acquisitions	2004
Deferred tax liabilities					
Property, plant and equipment	52,620	(1,066)	(1,883)	36,167	19,402
Inventories	90	(3)	(1,479)	1,445	127
Payables	291	-	223	68	-
Borrowings received	-	(3)	(142)	-	145
Other taxable temporary differences	113	(2)	115	-	-
Deferred tax assets					
Receivables	(155)	6	5	-	(166)
Dismantlement provision	(190)	7	219	(188)	(228)
Payables	(360)	14	158	(190)	(342)
Inventories	(114)	4	87	-	(205)
Other deductible temporary differences	(555)	19	(93)	(429)	(52)
Tax losses	(640)	16	(365)	-	(291)
Net deferred tax liability	51,100	(1,008)	(3,155)	36,873	18,390

The movement in deferred tax assets and liabilities during the year ended 31 December 2004 was as follows:

	2004	Recognized in equity for translation differences	Charged (credited) to the statement of operations	Effect of acquisitions	2003
Deferred tax liabilities					
Property, plant and equipment	19,402	372	(40)	19,070	-
Inventories	127	2	-	125	-
Borrowings received	145	2	-	143	-
Deferred tax assets					
Receivables	(166)	(55)	21	(132)	-
Dismantlement provision	(228)	(5)	-	(223)	-
Payables	(342)	(5)	-	(337)	-
Inventories	(205)	(3)	-	(202)	-
Other deductible temporary differences	(52)	(20)	19	(51)	-
Tax losses	(291)	(11)	(280)	-	-
Net deferred tax liability	18,390	277	(280)	18,393	-

There is no concept of consolidated tax returns in the Russian Federation and, consequently, tax losses and current tax assets of different subsidiaries cannot be set off against tax liabilities and taxable profits of other subsidiaries. Accordingly, taxes may accrue even where there is a net consolidated tax loss. Similarly, deferred tax assets of one subsidiary cannot be offset against deferred tax liabilities of another subsidiary. At 31 December 2005 and 2004, deferred tax assets of $2.000 million and $1.754 million, respectively, have not been recognized for deductible temporary differences for which it is not probable that sufficient taxable profit will be available to allow the benefit of that deferred tax asset to be utilised.

The Group has not recognised deferred tax liabilities for temporary differences associated with investments in subsidiaries as the Group is able to control the timing of the reversal of those temporary differences and does not intend to reverse them in the foreseeable future. At 31 December 2005 and 2004, the estimated unrecorded deferred tax liabilities for such differences were $1.395 million and $0.638 million, respectively.

Taxes payable at 31 December 2005 and 2004 were as follows:

	31 December:	
	2005	**2004**
Income taxes payable	6,039	387
Unified production tax	2,257	654
Value added tax	1,311	577
Other taxes payable	1,880	299
Total taxes payable	11,487	1,917

10 Borrowings

All borrowings outstanding at 31 December 2005 were denominated in US Dollars.

Short-term borrowings. Short-term borrowings and current portion of long-term borrowings were as follows at 31 December 2005 and 2004.

	31 December:	
	2005	**2004**
Loan from Alfa Eco M	-	10,993
Related party borrowings	-	27,493
Current portion of long-term borrowings	34,117	-
Total short-term borrowings and current portion of long-term borrowings	34,117	38,486

Loan from Alfa Eco M. Alfa Eco M is related to previous shareholders of Petrosakh (Note 4). The loan was rouble denominated, bore interest at 9.5 percent per annum and was fully repaid in June 2005.

Related party borrowings. At 31 December 2005 and 2004, outstanding borrowings from related parties totalled nil and $27.5 million, respectively. The borrowings, which were fully repaid or converted to shares of the Group during 2005, were unsecured and from shareholders and companies controlled by shareholders. All borrowings were denominated in US dollars except those from Nafta (B) NV, which were denominated in Euros.

The table below outlines all activity on related party borrowings outstanding at 31 December 2004.

Name of party	**31 December 2005**	**31 December 2004**	**Date of repayment/ conversion (2005)**
Shareholders – settled against unpaid capital			
Hillsilk Limited	-	330	March
Shareholders – converted to shares			
Radwood Business Inc.	-	500	August
Polaris Business Limited	-	300	August
Citara International Limited	-	5,000	August
Fantin Finance Limited	-	3,000	August
Shareholders – converted to shares and settled against unpaid capital			
Texas Oceanic Petroleum LLC	-	1,500	August
Controlled by shareholders – settled against unpaid capital			
UEN Trading Limited	-	8,660	March
Controlled by shareholders – converted to shares			
Nafta (B) NV	-	6,822	June
Other	-	1,381	
Total related party borrowings	-	27,493	

Shareholders. During 2005, the $0.330 million loan due to Hillsilk Limited and $1.0 million of the $1.5 million loan due to Texas Oceanic Petroleum LLC were converted to equity as settlement of the shareholders’ unpaid share capital balances (Note 12) and the remaining $0.5 million were converted to additional shares of the Group (Note 12).

In July 2005, the Group amended its loan agreements with Radwood Business Inc., Polaris Business Limited, Citara International Limited, Fantin Finance Limited and Texas Oceanic Petroleum LLC (who collectively at 31 December 2004, provided $9.3 million, Libor plus 2.0 percent unsecured notes to the Group), whereby the loan interest was restated to 15.0 percent per annum, effective retroactively to the origination of the loan. In August 2005, the balance of the loans, including unpaid interest, were extinguished by issuing 3,879,844 shares at a conversion rate of $2.65 per share, the estimated fair value of the Group's shares at the time the conversion was agreed.

In accordance with IAS 39, *Financial Instruments, Recognition and Measurement*, this modification and conversion comprise an extinguishment of debt. Accordingly, the difference of $0.6 million between the carrying value of the borrowings at the time of the extinguishment and the fair value of the consideration provided by the Group were recognized as a loss on extinguishment of debt in the consolidated statement of operations.

Controlled by shareholders. During 2005, the $8.660 million loan due to UEN Trading Limited was converted to equity as settlement of a portion of UEN Cyprus Limited's unpaid share capital balance (Note 12).

In June 2005, the Group settled its obligation to Nafta (B) NV by issuing shares at $2.65 per share (Note 12).

Long-term borrowings. Long-term borrowings were as follows at 31 December 2005 and 2004.

	31 December:	
	2005	**2004**
BNP Paribas Reserve Based Loan Facility	69,000	-
Bank Zenit	12,000	-
Other	122	-
Subtotal	81,122	-
Less: current portion of long-term borrowings	(34,117)	-
Total long-term borrowings	47,005	-

BNP Paribas Reserve Based Loan Facility. In November 2005, the Group closed a five year, revolving Reserve Based Loan Facility with BNP Paribas, underwritten to a maximum commitment of $100.0 million. In November 2005, the maximum amount then available of $69.0 million was drawn. The facility is divided into a senior conforming tranche of $59.0 million that bears interest at LIBOR plus 5.0 percent and a junior non-conforming tranche of $10.0 million priced at LIBOR plus 6.25 percent. Both tranches are repayable in full in December 2010. The loan was collateralized by liens on property, plant and equipment of subsidiaries (Note 7). The Group is subject to certain financial and other technical covenants under the BNP Paribas Reserve Based Loan Facility including the maintenance of a minimum financial ratios. The Group is in compliance with its covenants under the facility at 31 December 2005.

Bank Zenit. In March 2005, the Chepetskoye and CNPSEI entered into two loan agreements with Bank Zenit totalling $12.0 million. The loan agreements bore interest at 11.0 percent per annum and were scheduled to mature in March 2010. The loans contained cross default provisions and were collateralized by liens on property, plant and equipment of these subsidiaries (Note 7). This loan was repaid in February 2006.

BNP Paribas Bank Credit Facility. In June 2005, the Petrosakh entered into a $20.0 million, 18 month per-export credit facility with BNP Paribas Bank. This variable interest debt facility bore interest at LIBOR plus 5.0 percent and was originally repayable in December 2006. This facility was repaid in full in November 2005.

RP Capital Group. In July 2005, the Group entered into a 10.0 percent convertible preferred note agreement with RP Capital Group for up to $15.0 million. In the event of a qualifying initial public offering (“IPO”) the notes were convertible into ordinary shares at a 20 percent discount to the IPO price. In July 2005 the Group issued $10.0 million of the convertible notes at par. These notes were converted into 2,929,651 shares in August 2005. No gain or loss was recognized on conversion.

Scheduled maturities of long-term borrowings outstanding were as follows:

	Scheduled maturities at 31 December:	
Year ended 31 December:	**2005**	**2004**
One year	34,117	38,486
Two to five years	47,005	-
Thereafter	-	-
Total long-term borrowings	81,122	38,486

11 Dismantlement Provision

The dismantlement provision represents the net present value of the estimated future obligation for dismantlement, abandonment and site restoration costs which are expected to be incurred at the end of the production lives of the oil and gas fields. The discount rate used to calculate the net present value of the dismantling liability was 13.0 percent.

	Year ended 31 December:	
	2005	2004
Opening dismantlement provision	950	-
Translation difference	(21)	20
Acquisitions	785	920
Additions	20	-
Changes in estimates	(1,145)	-
Change due to passage of time	224	10
Closing dismantlement provision	813	950

As further discussed in Note 17, environmental regulations and their enforcement are under development by governmental authorities. Consequently, the ultimate dismantlement, abandonment and site restoration obligation may differ from the estimated amounts and this difference could be significant.

12 Equity

At 31 December 2005, the Group's authorized ordinary shares were 100 million, each having a par value of 0.0025 Cypriot pounds, of which 86.9 million were issued and outstanding shares at 31 December 2005.

In January 2006, the Group's shareholders approved a resolution increasing the authorized shares by 20 million to 120 million.

Share activity and other capital contributions for the two years ended 31 December 2005 are outlined below. All share amounts have been given retroactive effect for the 400:1 share split executed in July 2005.

	Number of shares (thousands of shares)	Share capital	Share premium	Unpaid capital
Balance at 31 December 2003	4,000	20	10	-
Share issuance	36,000	189	41,291	(11,324)
Contribution from shareholders	-	-	871	-
Balance at 31 December 2004	40,000	209	42,172	(11,324)
Partial conversion of Texas Oceanic Petroleum LLC loan	-	-	-	1,000
Conversion of UEN Trading Limited loan	-	-	-	8,660
Conversion of Hillsilk Limited	-	-	-	330
Conversion of other related party loans	-	-	-	1,027
Issuance of shares to Nafta (B) NV	9,434	50	24,950	-
Conversion of shareholder loans	3,880	20	10,261	-
Conversion of RP Capital Group loan	2,930	16	9,984	-
Shares issued for cash	30,667	165	113,946	-
Unpaid capital received in cash	-	-	-	307
Share-based payment	-	-	42	-
Balance at 31 December 2005	86,911	460	201,355	-

Urals Energy was created on 10 November 2003. Share capital at incorporation comprised 10,000 authorized and issued ordinary shares with a nominal value of one Cyprus Pound (CYP). In July 2004, the shareholders signed a Shareholder Agreement (the "Agreement") whereby, the Group issued an additional 90,000 ordinary shares for total consideration of $41.5 million. The share issuance was settled with in-kind contributions with a fair value of $17.5 million (comprising a 100 percent interest in Chepetskoye valued at $5.9 million, shareholder advances to group companies totalling $9.7 million and expenses incurred on behalf of the Group totalling $1.9 million) and cash of $24.0 million. At 31 December 2004, $11.3 million of the cash contributions remained unpaid.

In addition to contributions in accordance with the Shareholder's Agreement, during 2004, the shareholders also contributed their equity interest in OOO Urals Energy with a fair value of $0.9 million. This contribution was recorded as additional paid-in capital.

Partial conversion of Texas Oceanic Petroleum LLC loan. In May 2005, $1.0 million of the $1.5 million loan due to Texas Oceanic Petroleum LLC was converted to equity as settlement of Texas Oceanic Petroleum's unpaid share capital (Note 10). The remaining balance was converted to shares of the Group.

Conversion of UEN Trading Limited loan. In March 2005, the $8.660 million loan due to UEN Trading Limited was converted to equity as settlement of UEN Cyprus Limited's unpaid share capital (Note 10).

Issuance of shares to Nafta (B) NV. In June 2005, the Group issued 9,434 ordinary shares to Nafta (B) NV, a company owned in majority by two of the shareholders, for total consideration of $25.0 million. The share issuance was settled with a cash contribution of $18.4 million and conversion of $6.6 million in existing debt of Nafta B.

Conversion of shareholder loans. In August 2005, the Group extinguished its loans from Radwood Business Inc., Polaris Business Limited, Citara International Limited, Fantin Finance Limited and Texas Oceanic Petroleum LLC by issuing 3,879,844 shares at a conversion rate of $2.65 per share (Note 10).

Conversion of RP Capital Group loan. In August 2005, the Group extinguished $10.0 million of debt outstanding to RP Capital Group by issuing 2,929,651 shares (Note 10).

Shares issued for cash. In August 2005, the Group completed an initial public offering of its shares. As part of the offering, the Group issued 30,667,050 shares in exchange for $114.1 million, net of transaction costs.

Share-based payments. During 2005, the Group granted a share-based award to one of its officers. Under the award, the officer shall have the option to purchase a certain number of the Group's shares at a share price equal to $131 million divided by the number of Group shares that are issued and outstanding at both 1 August 2006 and 1 August 2007. The option is in two parts comprised of the number of shares that can be purchased for a payment of $125,000 on 1 August 2006 and of $125,000 on 1 August 2007, which are the respective vesting dates of the two parts of the award. The officer is required to be continuously employed by the Group through the vesting dates. Notification of intent to purchase must be submitted within three days of the respective dates, and payment and delivery of shares to the officer are to occur within 15 days of the respective dates.

During 2005, the Group estimated the total fair value of the award to be $0.067 million, of which $0.042 million was recognized during 2005 within selling, general and administrative expenses, with respect to this award. The full amount of the award is being recognized over its vesting period. The Black-Scholes option valuation model, used for valuing this award, was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, this option valuation model requires the input of highly subjective assumptions, including the expected stock price volatility. As the Group's shares were not publicly traded at the time of the grant of this award, management estimated the volatility measure through consultation with independent experts. Changes in the subjective input assumptions can materially affect the fair value estimate. Based on the assumptions below, the weighted average fair value of this option was estimated to be $0.067 million. Significant assumptions included in the option valuation model are summarized as follows.

Share price	$2.65
Dividend yield	-
Expected volatility	25.00%
Risk-free interest rate	4.00%
Expected life	1-2 years

13 Revenues

	Year ended 31 December:	
	2005	**2004**
Crude oil		
Export sales	69,177	2,546
Domestic sales (Russian Federation)	13,433	3,774
Petroleum (refined) products – domestic sales	9,904	1,643
Other sales	404	221
Total gross revenues	92,918	8,184

14 Cost of Production

	Year ended 31 December:	
	2005	**2004**
Depreciation and depletion	8,285	507
Unified production tax	16,829	1,394
Cost of purchased products	12,455	-
Wages and salaries (including payroll taxes of $1.457 million and $0.230 million for the years ended 31 December 2005 and 2004, respectively)	7,341	647
Materials	2,276	189
Other	3,256	1,615
Total cost of production	50,442	4,352

15 Selling, General and Administrative Expenses

	Year ended 31 December:	
	2005	2004
Wages and salaries	5,179	1,197
Audit and professional consultancy fees	2,542	2,767
Office rent and other expenses	1,522	759
Other taxes	1,338	312
Transport and storage services	998	102
Loading services	845	-
Loss on disposal of assets	254	14
Other expenses	1,290	1,674
Total selling, general and administrative expenses	13,968	6,825

16 Mobilization Costs

The Group's mineral licenses require that the Group perform certain exploration, evaluation and development activities as a condition of maintaining and/or renewing the licenses. During 2005, the Group entered into an agreement with KCA Deutag to provide a specialized drilling rig for the purpose of obligatory exploratory drilling on one of the Group's properties on Sakhalin Island. As part of the agreement, the Group was required to transport the rig approximately 5,000 kilometres to reach Sakhalin Island. By disclosing the agreements to secure and transport the rig, management was able to demonstrate to the licensing authorities its commitment to fulfilling its obligations under the license. However, due to delays in transportation and seasonal weather concerns, the Group was forced to terminate its agreement and abort the transport prior to the rig's arrival to Sakhalin Island, resulting in mobilization costs of $7.2 million being expensed during 2005.

The Group was subsequently able to modify an existing rig to drill an exploratory well on the property in order to maintain compliance with the license terms.

17 Contingencies, Commitments and Operating Risks

Operating environment of the Group. Whilst there have been improvements in economic trends in the country, the Russian Federation continues to display certain characteristics of an emerging market. These characteristics include, but are not limited to, the existence of a currency that is not freely convertible in most countries outside of the Russian Federation, restrictive currency controls, and relatively high inflation. The tax, currency and customs legislation within the Russian Federation is subject to varying interpretations, and changes, which can occur frequently.

The future economic direction of the Russian Federation is largely dependent upon the effectiveness of economic, financial and monetary measures undertaken by the Government, together with tax, legal, regulatory, and political developments.

Sales and royalty commitments. In accordance with Petrosakh's license terms, Petrosakh is required to sell 20.0 percent of its annual oil production in the form of petroleum products to the Sakhalin Island region at market prices.

In accordance with the sale purchase agreement to acquire Petrosakh, the Group agreed to pay a perpetual royalty to the previous shareholders of $0.25 per ton of crude oil produced from the currently unproved off-shore licensed area.

Exploration licenses – investment commitments. The Company's application for an extension of the Pogranichnoye License area offshore Sakhalin Island has been successful. The Russian Federal Agency for Natural Resources granted the license extension in January 2006. The license period was extended to 1 February 2011 and the terms of the amended license now require a total of five exploration wells to be drilled during the period 2005-2010. The East Okruzhnoye No. 1 well spudded in 2005 will qualify as the first of the five exploration wells required by the amended license. Management currently estimate such expenditure to approximate $19.0 million.

Urals Nord has five geological studies licenses which expire in January 2008. According to the license agreement terms Urals Nord is required to drill exploration wells and perform seismic works. Management currently estimate such expenditure to approximate $36 million.

Other capital commitments. At 31 December 2005 and 2004 the Group had no other significant contractual commitments for capital expenditures.

Taxation. Russian tax, currency and customs legislation is subject to varying interpretations, and changes, which can occur frequently. Management's interpretation of such legislation as applied to the transactions and activity of the Group may be challenged by the relevant regional and federal authorities. Recent events within the Russian Federation suggest that the tax authorities may be taking a more assertive position in their interpretation of the legislation and assessments, and it is possible that transactions and activities that have not been challenged in the past may be challenged. As a result, significant additional taxes, penalties and interest may be assessed. Fiscal periods remain open to review by the authorities in respect of taxes for three calendar years preceding the year of review. Under certain circumstances reviews may cover longer periods.

As at 31 December 2005 and 2004 management believes that its interpretation of the relevant legislation is appropriate and the Group's tax, currency and customs positions will be sustained. Where management believes it is probable that a position cannot be sustained, an appropriate amount has been accrued for in these financial statements.

Insurance policies. At 31 December 2005, the Group held limited insurance policies in relation to its assets, operations, or in respect of public liability or other insurable risks. Since the absence of insurance alone does not indicate an asset has been impaired or a liability incurred, no provision has been made in these financial statements.

Restoration, rehabilitation and environmental costs. The Group companies have operated in the upstream and refining oil industry in the Russian Federation for many years and its activities have had an impact on the environment. The enforcement of environmental regulations in the Russian Federation is evolving and the enforcement posture of government authorities is continually being reconsidered. The Group periodically evaluates its obligation related thereto. The outcome of environmental liabilities under proposed or future legislation, or as a result of stricter enforcement of existing legislation, cannot reasonably be estimated at present, but could be material. Under the current levels of enforcement of existing legislation, management believes there are no significant liabilities in addition to amounts which are already accrued and which would have a material adverse effect on the financial position of the Group.

Legal proceedings. During the year, the Group was involved in a number of court proceedings (both as a plaintiff and a defendant) arising in the ordinary course of business. In the opinion of management, there are no current legal proceedings or other claims outstanding, which could have a material effect on the result of operations or financial position of the Group and which have not been accrued or disclosed in these consolidated financial statements.

Oilfield licenses. The Group is subject to periodic reviews of its activities by governmental authorities with respect to the requirements of its oil filed licenses. Management of the Group correspond with governmental authorities to agree on remedial actions, if necessary, to resolve any findings resulting from these reviews. Failure to comply with the terms of a license could result in fines, penalties or license limitations, suspension or revocations. The Group's management believes any issues of non-compliance will be resolved through negotiations or corrective actions without any materially adverse effect on the financial position or the operating results of the Group.

18 Financial Risks

Foreign exchange risk. The Group has substantial amounts of foreign currency denominated long-term borrowings and is thus exposed to foreign exchange risk. Foreign currency denominated assets and liabilities give rise to foreign exchange exposure. The Group does not have formal arrangements to mitigate foreign exchange risks.

Interest rate risk. The Group's income and operating cash flows are substantially independent of changes in market interest rates. The Group obtains funds from, and deposits its cash surpluses with, banks at current market interest rates, and does not utilize hedging instruments to manage its exposure to changes in interest rates. The details of interest rates associated with the Group's borrowings are discussed in Note 10.

The carrying value of the Group's receivables, payables and borrowings approximate their fair values (Note 3).

Credit risk. Financial assets, which potentially subject Group entities to credit risk, consist principally of trade receivables. The Group has policies in place to ensure that sales of products and services are made to customers with an appropriate credit history. The carrying amount of accounts receivable, net of provision for impairment of receivables, represents the maximum amount exposed to credit risk. The Group has no other significant concentrations of credit risk. Although collection of receivables could be influenced by economic factors, management believes that there is no significant risk of loss to the Group beyond the provision already recorded.
Cash is placed in financial institutions, which are considered at time of deposit to have minimal risk of default.

Commodity and pricing risk. The Group's operations are significantly affected by the prevailing price of crude oil both in the international oil market and in the Russian Federation. Crude oil prices have historically been highly volatile, dependent upon the balance between supply and demand and particularly sensitive to OPEC production levels. Crude oil prices in the Russian Federation are below international levels primarily due to constraints on the export of crude oil. Also, domestic crude oil prices are contract specific as there is no active market for domestic crude oil and marker prices are not available. There is typically no straight correlation between domestic and international oil prices. The Group's subsidiary - Petrosakh, operates on Sakhalin Island where the surrounding ocean is not navigateable for several months of the year, this further increases the exposure to commodity price risk.

19 Related-Party Transactions

For the purposes of these financial statements, parties are considered to be related if one party has the ability to control the other party, is under common control, or can exercise significant influence over the other party in making financial or operational decisions as defined by IAS 24 Related Party Disclosures. In considering each possible related party relationship, attention is directed to the substance of the relationship, not merely the legal form.

Trading relationship with related parties. The Group has transactions in the ordinary course of business with ZAO NC Urals, ZAO "Chepetskoye" NGDU (through July 2004, when contributed by the Group shareholder to Urals Energy), Urals ARA NV and Nafta (B) NV which all are controlled by major shareholders. These transactions include sales and purchases of crude oil and petroleum products. Such sales ended beginning September 2005. Below are the annual sales, purchases and receivables balances for each year presented:

	As of or for the year ended 31 December:	
	2005	**2004**
Sales of crude oil on export markets	5,515	2,212
Associated volumes, tons	17,580	9,000
Sales of petroleum products on domestic markets	-	212
Associated volumes, tons	-	
Purchases of crude oil	-	1,178
Associated volumes, tons	-	10,950
Commission revenue		24
Interest income	-	-
Interest expense	77	135
Management fees received	-	208
Rental fees paid (included in selling, general and administrative expense)	306	264
Other expenses	790	232
Accounts and notes receivable	1,474	-
Loans receivable	1,251	723
Other payables and accrued expenses	74	61
Trade advances received	3	800

Lending relationships with related parties. See Note 10 for details of loans from shareholders and from companies controlled by shareholders.

Guarantees issued to parties related to previous shareholders of subsidiaries. In September 2004, CNPSEI issued a $1.5 million guarantee to secure borrowings of OOO Neftegazrazvitiye, a former shareholder. The loan bore interest of 14.0 percent per annum. OOO Neftegazrazvitiye defaulted on its obligations and therefore failed to repay the loan. CNPSEI, as the guarantor repaid a portion of the loan during 2004 and the remainder during 2005. The Group's obligation was recognised at its fair value in the purchase price adjustment in the accompanying financial statements. Accordingly, there was no impact on the Group's statement of operations for the years ended 31 December 2005 and 2004.

Compensation to senior management. The Group's senior management team comprises 10 people whose compensation totalled $4.174 million and $1.917 million for the periods ended 31 December 2005 and 2004, respectively, including salary and bonuses of $4.106 million and $1.917 million respectively, and stock compensation of $0.042 million and nil, respectively, and no other compensation was paid for both years.

20 Subsequent Events

Subordinated loan. In January 2006, the Group obtained a $12.0 million subordinated loan from BNP Paribas. The subordinated loan bears interest at LIBOR plus 5.0 percent and is repayable over five years in one payment on 10 November 2010. Attached to the subordinated loan were warrants to purchase up to two million of the Group's common stock for £3.03. The warrants are exercisable at any time and expire in November 2010. The Group used the proceeds from the subordinated loan to repay its debt to bank Zenit of $12.0 million.

Share-based payments. In February 2006, the Group's Board of Directors approved a Restricted Stock Plan (the "Plan") authorizing the Compensation Committee of the Board of Directors to issue restricted stock of up to five percent of the outstanding shares of the Group. Upon adoption, the Group issued 1,561,725 shares of restricted stock. The vesting schedule for the restricted stock varies by individual award and, of the February 2006 grant, 1,040,445 shares, 260,625 shares and 260,625 shares vest on 1 January 2007, 2008 and 2009, respectively.