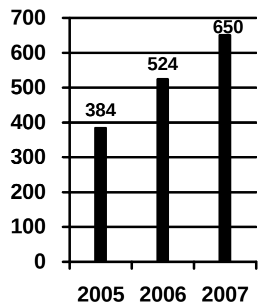
Husky Energy

Q1/07

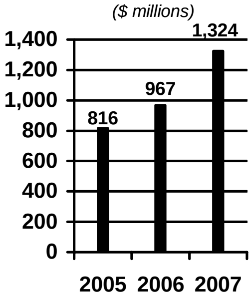
Quarterly Report to the Shareholders for the period ended March 31, 2007

HUSKY ENERGY REPORTS 2007 FIRST QUARTER RESULTS

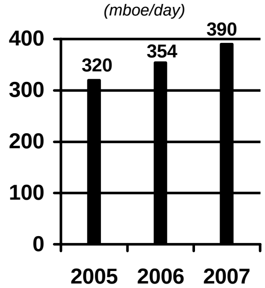
First Quarter
Net Earnings
($ millions)



First Quarter
Cash Flow
from Operations
($ millions)



First Quarter
Total Production
(mboe/day)



Calgary, Alberta – Husky Energy Inc. reported net earnings of $650 million or $1.53 per share (diluted) in the first quarter of 2007, an increase of 24% from $524 million or $1.24 per share (diluted) in the same quarter of 2006. Cash flow from operations in the first quarter was $1,324 million or $3.12 per share (diluted), a 37% increase compared with $967 million or $2.28 per share (diluted) in the same quarter of 2006. Sales and operating revenues, net of royalties, were $3.2 billion in the first quarter of 2007, up 5% compared with $3.1 billion in the first quarter of 2006.

"Husky continues to achieve strong financial results in terms of net earnings, cash flow from operations and production," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "We are pleased to have regulatory approval for production rate increases at the White Rose oil field to 140,000 barrels per day. East Coast Canada is a strategic core area for us and we are evaluating opportunities to develop the newly discovered resources from the West White Rose and North Amethyst fields."

In the first quarter of 2007, total production averaged 390,000 barrels of oil equivalent per day, a 10% increase over the 353,600 barrels of oil equivalent per day in the first quarter of 2006. Total crude oil and natural gas liquids production increased 18% to 283,300 barrels per day, compared with 239,400 barrels per day in the first quarter of 2006. Natural gas production was 640.0 million cubic feet per day, down 7% from the same period last year, due primarily to delays in drilling and tie-ins.

Production at the White Rose oil field averaged 89,400 barrels per day net to Husky in the first quarter. With the latest regulatory and government approval, current reservoir capacity of 125,000 barrels per day is expected to increase to 140,000 barrels per day with the completion of a seventh production well in mid-2007.

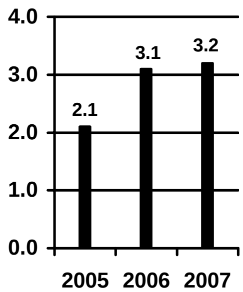
At the Tucker Oil Sands project, production rates are improving with approximately half of the 32 well pairs in production mode and the remaining well pairs in initial steaming mode. Production rates are expected to reach the target level of 30,000 barrels per day over the next 20 months.

The Sunrise Oil Sands project continues to progress with completion of the front-end engineering design work planned for the end of 2007. Solutions for the transporting, upgrading and refining of the bitumen are proceeding.

At Caribou Lake and Saleski, Husky has completed 2-D and 3-D seismic data and conducted drilling activity to further define the resource at these locations.

First Quarter Sales and Operating Revenues

($ billions)



Internationally, Husky completed the interpretation of the 3-D seismic data acquired over the Liwan natural gas discovery offshore China. The Company plans to acquire additional seismic over Block 29/26 and the adjacent Block 29/06 later this year. During the first quarter of 2007, we signed an agreement to secure a deep-water drilling rig for a three year term commencing in mid-2008.

In Indonesia, negotiations for a Gas Sales Agreement and a Madura Production Sharing Contract are progressing. The amended development plan for the Madura BD project will be submitted to regulators for approval once the terms for a Gas Sales Agreement are finalized.

The debottlenecking of the Lloydminster Upgrader from 77,000 barrels per day to 82,000 barrels per day is expected to be complete following a scheduled 40-day turnaround in the second quarter. Front-end engineering design work to double the capacity of the Upgrader to a potential capacity of 150,000 barrels per day continues with work expected to be complete by the end of 2007.

In Minnedosa, construction of the new ethanol production facility is currently 50% complete with commissioning expected in the third quarter of 2007.

Husky continues to strengthen its financial position. Total long-term debt including current portion at March 31, 2007 was $1,527 million, a 5% decrease from $1,611 million at December 31, 2006.

First Quarter Financial Highlights 2007 versus 2006

- Earnings per share to $1.53 from $1.24
- Return on equity to 32.1% from 29.6%
- Return on average capital employed to 27.3% from 23.2%
- Cash flow per share to $3.12 from $2.28
- Debt to capital employed ratio to 14% from 19%
- Debt to cash flow ratio to 0.3 from 0.5
- Market capitalization increased to $34 billion from $30 billion

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") APRIL 17, 2007

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1.0 QUARTERLY FINANCIAL RESULTS

Husky's net earnings for the first quarter of 2007 were $650 million, up $126 million or 24% compared with the first quarter of 2006.

Higher earnings in the first quarter of 2007 were mainly due to higher crude oil production from the White Rose and Terra Nova oil fields, higher medium and heavy crude oil prices and higher light refined product margins and sales volume. Positive factors were partially offset by lower natural gas and light crude oil prices and lower Western Canada sales volume of crude oil and natural gas, higher depletion and depreciation expense in the upstream business segment, narrower upgrading differential, higher feedstock costs for asphalt production and higher income taxes.

Financial Summary

(millions of dollars, except per share amounts and ratios)		Three months ended March 31 **2007**	2006
Segmented earnings			
Upstream		**$ 580**	$ 412
Midstream		**111**	150
Refined Products		**20**	16
Corporate and eliminations		**(61)**	(54)
Net earnings		**$ 650**	$ 524
Per share - Basic and diluted		**$ 1.53**	$ 1.24
Cash flow from operations		**1,324**	967
Per share - Basic and diluted		**3.12**	2.28
Ordinary quarterly dividend per common share		**0.50**	0.25
Special dividend per common share		**0.50**	-
Total assets		**17,781**	15,855
Total long-term debt including current portion		**1,527**	1,838
Return on equity [(1)]	*(percent)*	**32.1**	29.6
Return on average capital employed [(1)]	*(percent)*	**27.3**	23.2

[(1)] *Calculated for the 12 months ended for the dates shown.*

2.0 CORE BUSINESS STRATEGY

Our core business strategy was detailed in our 2006 annual Management's Discussion and Analysis, which is available from the Canadian Securities Administrator's web site, www.sedar.com, the Securities Exchange Commission's web site, www.sec.gov or our web site www.huskyenergy.ca.

In summary, our strategy is to continue to exploit our conventional oil and gas asset base in Western Canada while expanding into new areas with large scale sustainable growth potential. Our plans include projects in the Alberta oil sands, the basins off the East Coast of Canada, the central Mackenzie River Valley, the South China Sea, Madura Strait and the East Java Sea. Our plans for the Midstream and Refined Products segments involve enhancing performance and capturing new value throughout the value chain by further integrating our operations, optimizing our plant operations and expanding plant and infrastructure where warranted.

3.0 CAPABILITY TO DELIVER RESULTS

Our current capacity to deliver results is described in our recently filed MD&A and also in our Annual Information Form that are available from www.sedar.com and www.sec.gov. In order to deliver competitive results we must continually identify and develop an inventory of projects that will provide a satisfactory return on investment. The major projects that we are currently developing are discussed below.

3.1 UPSTREAM

WHITE ROSE OIL FIELD

At the end of the first quarter of 2007, the governments of Canada and Newfoundland and Labrador together with the Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") approved our application to increase production at the White Rose oil field to 50 mmbbls annually, with a maximum 140 mbbls/day, subject to several technical conditions that relate to safety, conservation and production control.

Current reservoir capacity of 125 mbbls/day is expected to increase to 140 mbbls/day with the completion of the seventh production well in mid-2007. Allowing for downtime associated with maintenance regulatory inspection, drilling rig movements and well tie-in activities, the White Rose oil field is expected to produce between 120 mbbls/day and 125 mbbls/day on an annual average basis.

An application to tie-in production from the South White Rose extension is currently undergoing regulatory review. Applications to develop the newly discovered resources from the West White Rose and North Amethyst fields are scheduled to be filed with the C-NLOPB in 2008. These developments are expected to result in a significant extension of the production plateau and life of the White Rose oil field.

The front-end engineering design studies to tie-back satellite reservoirs to the *SeaRose FPSO* have progressed to approximately 30% completion. The scope of these studies has expanded and now includes the South White Rose, North Amethyst and West White Rose oil pools. As a result of the increase in scope, the engineering work is now expected to be completed by the fourth quarter of 2007.

EAST COAST CANADA EXPLORATION AND WHITE ROSE DELINEATION

An additional delineation well is planned for later in 2007 to further define the West White Rose resource.

We are currently evaluating data from our recent 3-D seismic program, which was shot over Exploration Licences 1067 and 1011, to determine future drilling prospectivity.

TUCKER OIL SANDS PROJECT

During the first quarter, the Tucker Oil Sands project completed its commissioning and start-up phase. Half of the 32 well pairs are in production with the remaining well pairs in initial steaming mode. Production rates are expected to increase to 30,000 barrels per day over the next 20 months.

SUNRISE OIL SANDS PROJECT

The front-end engineering design of the Sunrise Oil Sands project is continuing and is approximately 40% complete. This work is expected to be completed by the fourth quarter of 2007. The first phase of the project will have a design rate of 60 mbbls/day and will ultimately be developed to a production plateau of 200 mbbls/day.

In the field, 29 stratigraphic test wells were drilled, cored and logged. Analysis of the data acquired is now underway. In addition, five additional water source wells and two observation wells were drilled. We also continued discussions and planning with various industry participants in respect of the general area's infrastructure needs. Discussions are continuing with regulatory authorities and stakeholders.

CARIBOU AND SALESKI

At Caribou we drilled 39 stratigraphic test wells, completed a 3-D seismic program and tested and cased two water source and four disposal wells. Engineering work during the quarter included modeling and simulation studies. Discussions and presentations proceeded during the quarter with the Alberta Energy and Utilities Board and several stakeholder groups.

During the first quarter of 2007, we acquired 2,560 acres in the Saleski area bringing our total landholdings in this area to 241,760 acres. Activity at Saleski also included drilling various test wells and gathering of 2-D and 3-D seismic data.

NORTHWEST TERRITORIES EXPLORATION

In the Central Mackenzie Valley where we have new oil and gas exploration prospects at Summit Creek and Stewart Lake, we are currently evaluating seismic data acquired in September 2006. We plan to undertake a drilling program in the winter of 2007/2008 to further appraise these discoveries.

CHINA EXPLORATION

During the first quarter of 2007, we signed an agreement to secure a deep-water rig for three years commencing in 2008. This rig will be used to delineate the Liwan natural gas discovery and undertake further exploratory drilling on Block 29/26 in the South China Sea.

We completed the interpretation of the 3-D seismic that was acquired over Liwan and expect to commence delineation drilling in mid-2008. We also plan to acquire additional seismic data over Block 29/26, which contains Liwan and Block 29/06, a plan precipitated by the initial Liwan data interpretation.

In the East China Sea we are preparing to drill one exploration well on Block 04/35. Our schedule remains to spud this well before the end of the year, contingent on rig availability.

INDONESIA NATURAL GAS DEVELOPMENT AND EXPLORATION

In Indonesia, our negotiations to execute a natural gas sales agreement progressed and we are currently awaiting approval from the Indonesian regulator, BPMIGAS. Our amended development plan for the BD natural gas and condensate field in the Madura Strait will be submitted to BPMIGAS for their approval, once the terms for the gas sales agreement are finalized.

Additionally, preparations are underway to acquire 3-D seismic data on our recently awarded exploration block, East Bawean II.

3.2 MIDSTREAM

LLOYDMINSTER TO HARDISTY PIPELINE EXPANSION

The first phase of our pipeline expansion from Lloydminster to Hardisty, Alberta, the intersection with the mainline of the Enbridge Pipeline, was completed in March 2007. The overall project is approximately 73% complete and is on schedule to be finished by the fourth quarter of 2007.

LLOYDMINSTER UPGRADER EXPANSION

The front-end engineering design for the potential expansion of the Lloydminster Upgrader has reached approximately 57% completion. We expect this work will be completed in the fourth quarter of 2007.

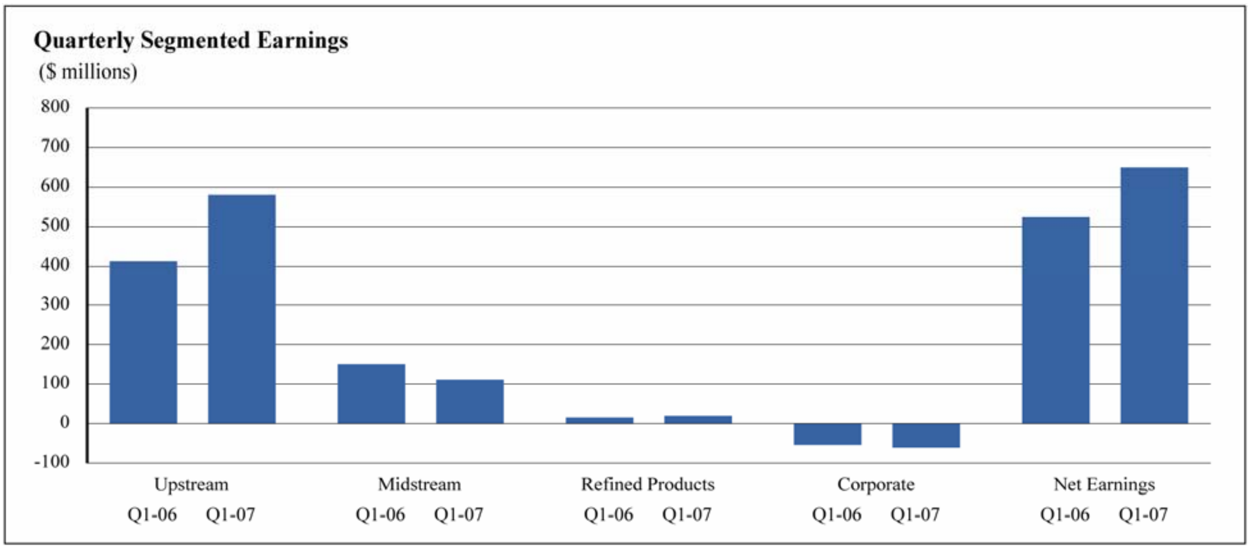
3.3 REFINED PRODUCTS

MINNEDOSA ETHANOL PLANT

At Minnedosa, the ethanol plant is 50% complete. We expect to commission the plant in the third quarter followed by full operation in the fourth quarter of 2007.

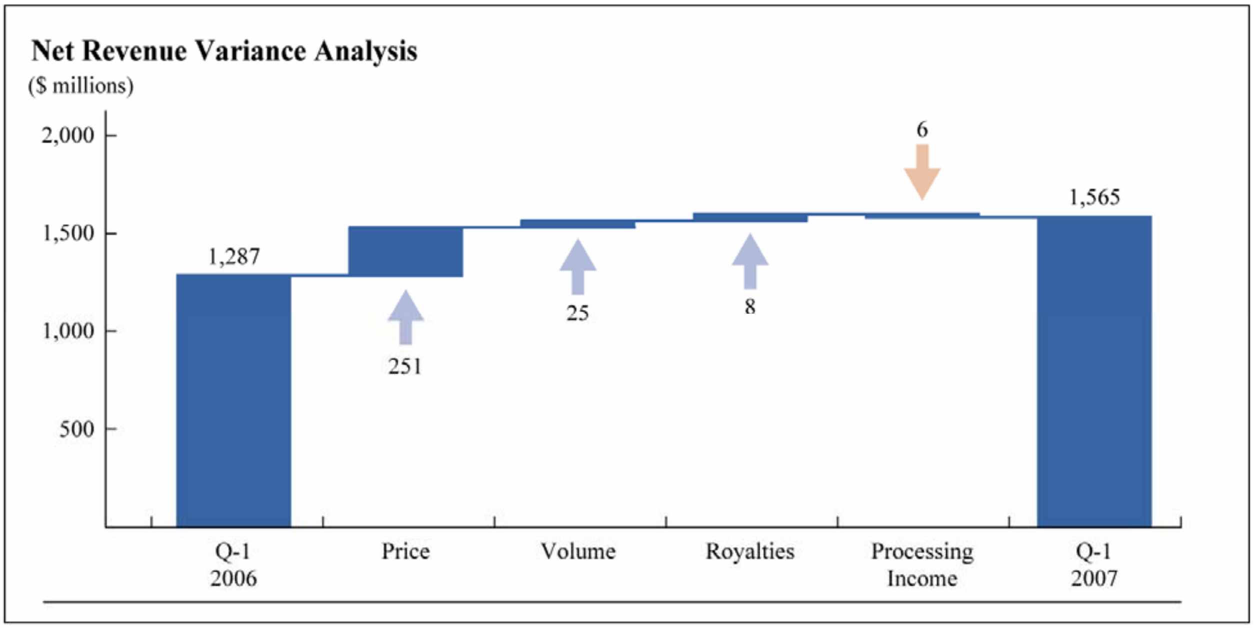
4.0 RESULTS OF OPERATIONS

The following table discloses earnings by major business segment and includes corporate expenses and intersegment profit elimination amounts, the aggregate of which is equal to consolidated net earnings.



4.1 UPSTREAM

Upstream Earnings Summary	Three months ended March 31	
(millions of dollars)	**2007**	2006
Gross revenues	**$ 1,763**	$ 1,493
Royalties	**198**	206
Net revenues	**1,565**	1,287
Operating and administration expenses	**323**	311
Depletion, depreciation and amortization	**399**	351
Income taxes	**263**	213
Earnings	**$ 580**	$ 412



THE UPSTREAM BUSINESS ENVIRONMENT

Commodity Prices

The prices we receive for our crude oil production are determined by global economic factors. The grade of our crude oil also affects the price we receive. The economics of refining crude oil into finished products such as gasoline and distillates favours light sweet crude oil over heavy sour crude oil because the light sweet feedstock yields a higher proportion of more valuable motor fuels, such as gasoline without the need to incur the additional costs of removing residual asphaltenes and sulphur.

Natural gas prices are not affected as much by global economics, but by local supply and demand because transportation of natural gas is generally still limited to pipelines.

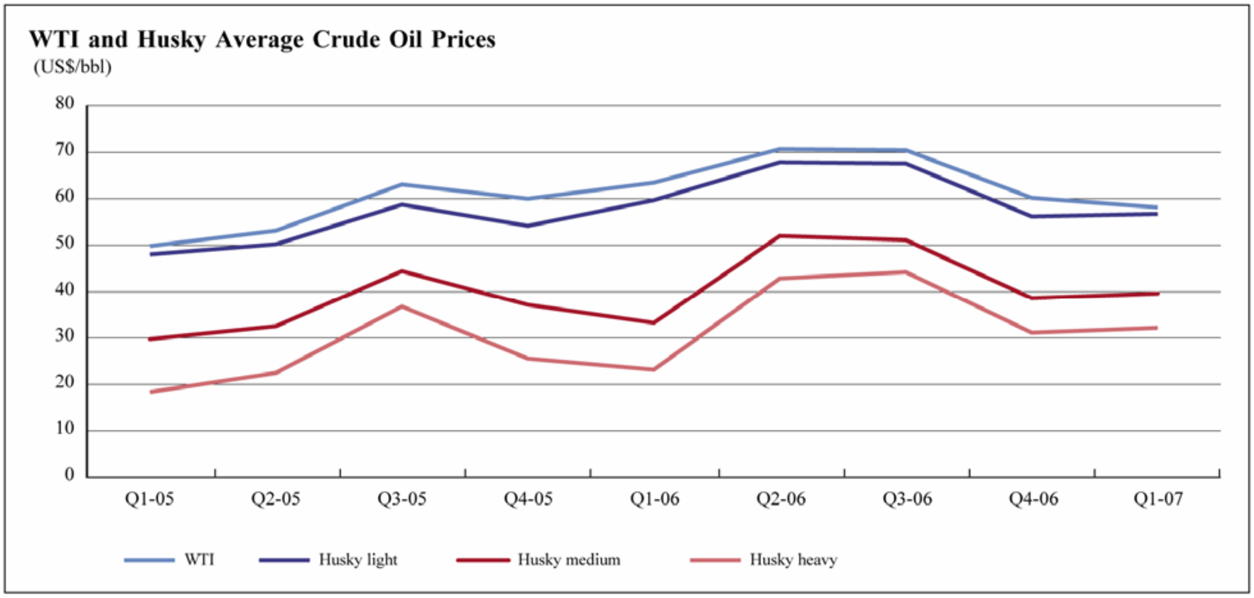
Our Upstream results are significantly influenced by commodity prices. The following table shows certain select average quarterly market benchmark prices:

Average Benchmark Prices and U.S. Exchange Rate		Three months ended				
		March 31 2007	Dec. 31 2006	Sept. 30 2006	June 30 2006	March 31 2006
WTI crude oil [1]	*(U.S. $/bbl)*	**58.16**	60.21	70.48	70.70	63.48
Brent crude oil [2]	*(U.S. $/bbl)*	**57.75**	59.68	69.49	69.62	61.75
Canadian light crude 0.3% sulphur	*($/bbl)*	**67.76**	65.12	79.65	78.97	69.40
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**38.25**	35.24	49.61	48.65	26.25
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**6.77**	6.56	6.58	6.79	8.98
NIT natural gas	*($/GJ)*	**7.07**	6.03	5.72	5.95	8.79
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**17.32**	21.75	19.24	17.99	29.20
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.854**	0.878	0.892	0.891	0.866

(1) *Prices quoted are near-month contract prices for settlement during the next month.*
(2) *Dated Brent prices which are dated less than 15 days prior to loading for delivery.*

Crude Oil

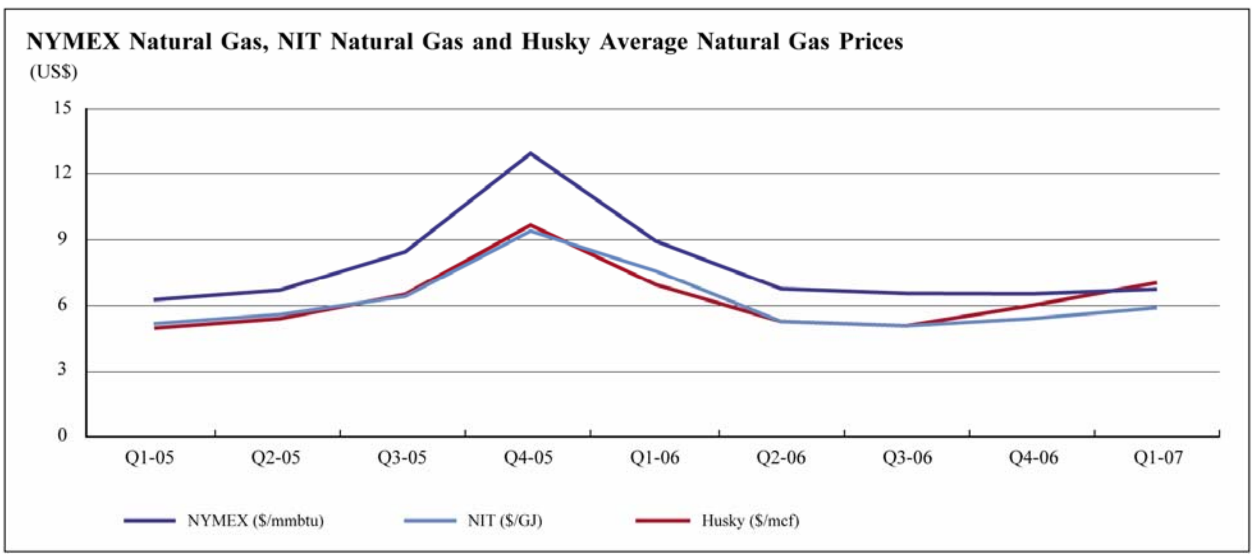
The following graph illustrates the relative changes over several quarters in the realized prices of our three main crude oil categories expressed in U.S. dollars and West Texas Intermediate ("WTI"), the main benchmark crude oil.



The majority of our crude oil production is marketed in North America and the primary benchmark crude oil is WTI. During the first quarter of 2007, WTI decreased from a January 1st price of U.S. $61/bbl to U.S. $50/bbl by January 18th and then returned to U.S. $62/bbl by March 7th, only to drop to U.S. $56/bbl, as many U.S. refineries began maintenance programs, and then back up to U.S. $63/bbl due to market reaction to an international dispute.

Natural Gas

The following graph illustrates the relative changes over several quarters in our natural gas price realized compared with two major benchmark prices.



During 2006, lower heating demand and higher natural gas supplies led to higher than average natural gas storage levels at the end of the year and throughout the first quarter of 2007. These events kept natural gas prices on the low side during the first quarter of 2007 relative to the first quarter of 2006. The NYMEX price for near month settlement averaged U.S. $6.77/mmbtu during the first quarter of 2007.

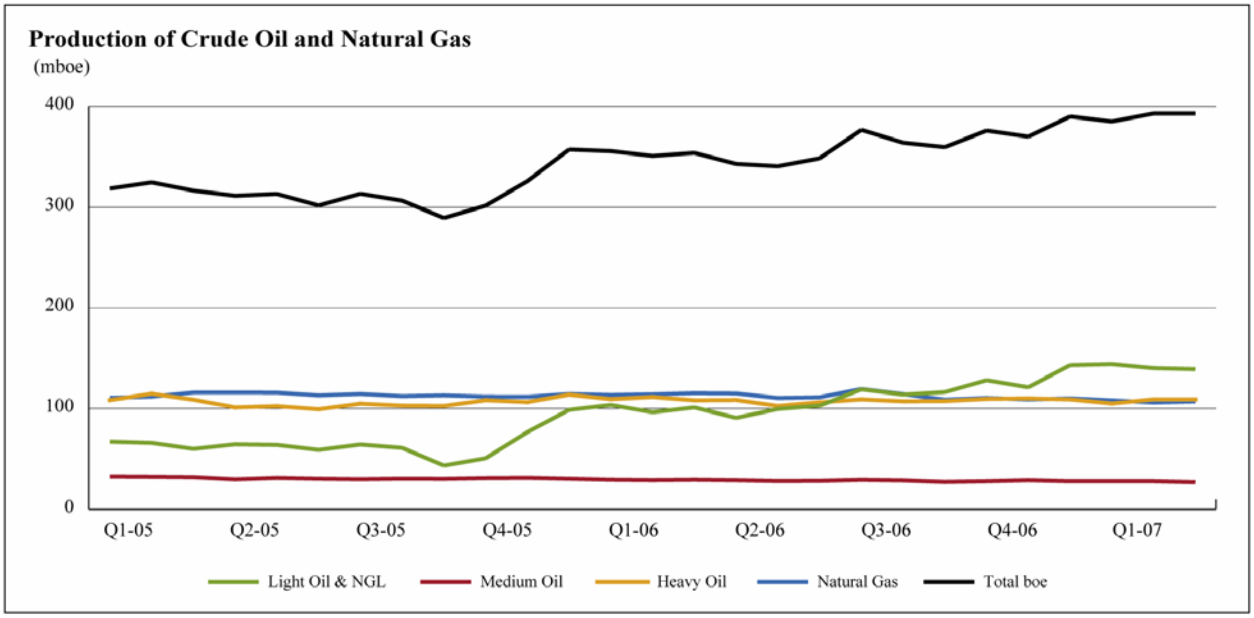
The average prices we realized during the first quarter of 2007 compared with the first quarter of 2006 are illustrated below.

Average Sales Prices		Three months ended March 31	
		2007	2006
Crude Oil	*($/bbl)*		
Light crude oil & NGL		**$ 64.88**	$ 67.04
Medium crude oil		**46.40**	38.39
Heavy crude oil		**37.67**	26.73
Total average		**52.70**	45.08
Natural Gas	*($/mcf)*		
Average		**6.94**	8.06

OIL AND GAS PRODUCTION

The following table discloses our gross daily production rate by location and product type for five sequential quarters.

Daily Gross Production		Three months ended				
		March 31	Dec. 31	Sept. 30	June 30	March 31
		2007	2006	2006	2006	2006
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**30.1**	30.4	30.2	29.8	31.3
Medium crude oil		**27.5**	28.0	28.1	28.5	29.4
Heavy crude oil & bitumen		**108.0**	109.5	107.9	105.6	109.5
		165.6	167.9	166.2	163.9	170.2
East Coast Canada						
White Rose - light crude oil		**89.4**	79.4	75.9	53.0	46.4
Terra Nova - light crude oil		**14.7**	6.7	-	2.8	9.3
China						
Wenchang - light crude oil & NGL		**13.6**	11.7	11.1	12.1	13.5
		283.3	265.7	253.2	231.8	239.4
Natural gas	*(mmcf/day)*	**640.0**	662.2	669.1	672.8	685.4
Total	*(mboe/day)*	**390.0**	376.1	364.7	344.0	353.6



Revenue

During the first quarter of 2007, our upstream net revenues were $1.6 billion, compared with $1.3 billion in the first quarter of 2006. Our revenues are affected largely by the volatility of oil and gas commodity prices. Our oil and gas production is predominately sold at the prevailing market prices and those prices are subject to the precarious balance between supply and demand on a global scale. A large number of factors can impact perceived supply and demand and those perceptions drive the oil and gas commodity markets up and down, all of which are beyond our control.

In the first quarter of 2007, Western Canada was the source of 58% of our crude oil and 100% of our natural gas production resulting in 59% of upstream revenue before royalties, the East Coast of Canada contributed 37% of our crude oil production, 76% of our light crude oil production and resulted in 36% of upstream revenue before royalties and China contributed 5% of revenue.

In the first quarter of 2006, Western Canada was the source of 71% of our crude oil and 100% of our natural gas production resulting in 70% of upstream revenue before royalties, the East Coast Canada contributed 23% of our crude oil production, 62% of our light crude oil production and resulted in 24% of upstream revenue before royalties and China contributed 6% of revenue.

Crude Oil Production

In the first quarter of 2007, Western Canada crude oil and NGL production declined 3% compared with the first quarter of 2006. Heavy crude oil production accounted for about half of the decrease, particularly from thermal operations, which are currently undergoing optimization and debottleneck work. The remainder of the decline was mainly lower medium crude oil and NGL production which resulted from natural reservoir declines not yet offset by new drilling.

Crude oil production from the White Rose and Terra Nova oil fields off the East Coast of Canada averaged 104.1 mbbls/day during the first quarter of 2007 compared with 55.7 mbbls/day during the first quarter of 2006, an increase of 87%. At White Rose, the productive capacity of the field increased to 125 mbbls/day with the completion of the sixth production well in November 2006. Production at Terra Nova was curtailed during the first quarter of 2006 as a result of protracted mechanical issues, which were resolved in late 2006.

At Wenchang in the South China Sea, production was marginally higher in the first quarter of 2007 compared to the same period in 2006. New production wells and well workovers in the fourth quarter of 2006 boosted production levels in the first quarter of 2007. The installation of gas liquid extraction facilities also augmented crude oil production.

On April 11, 2007, we closed a transaction to dispose of several properties located mainly in northwest Alberta and southwest Saskatchewan with current production of approximately 5,200 boe/day. Total proceeds amounted to $339 million.

Natural Gas Production

All of our natural gas production is from Western Canada. In the first quarter of 2007, the foothills of Alberta and British Columbia, the deep basin of Alberta and the plains of northeast British Columbia and northwest Alberta were the sources of 57% of our natural gas production, the remainder was from the plains throughout Alberta and southwest Saskatchewan.

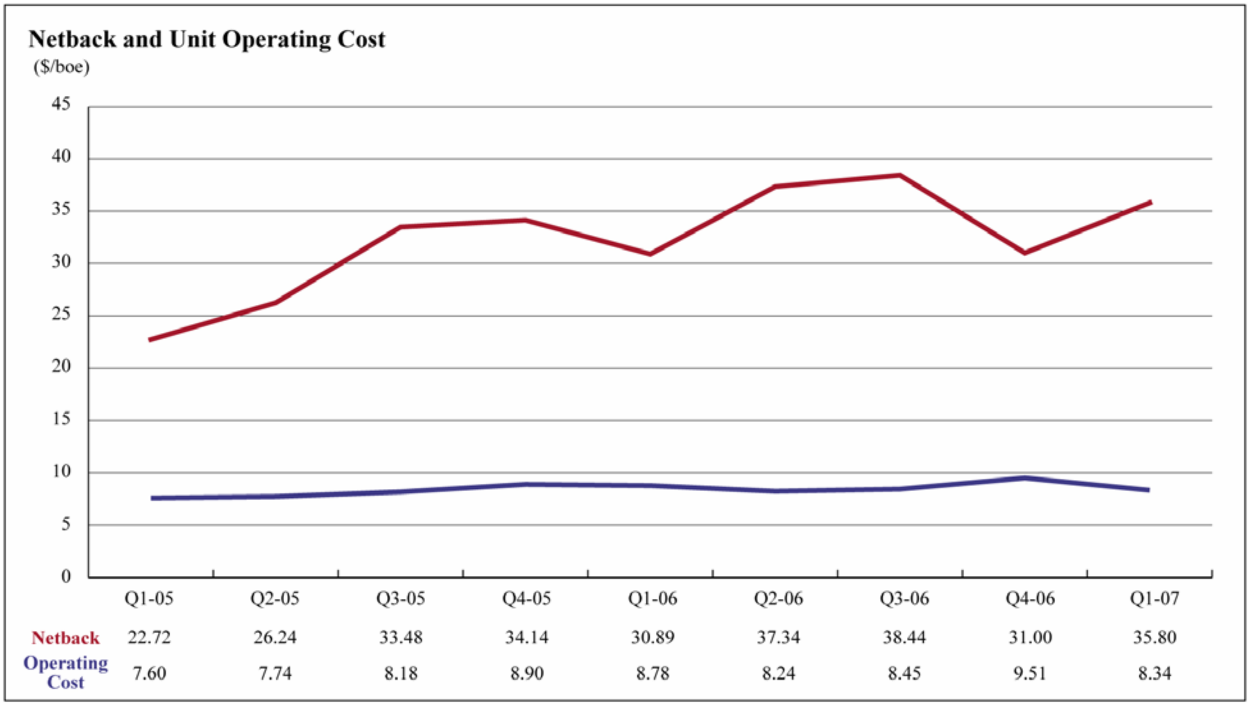
Production of natural gas was down approximately 7% in the first quarter of 2007 compared with the first quarter of 2006 primarily due to drilling and infrastructure delays, plant restrictions and mechanical related down-time.

2007 Gross Production Guidance		**Full Year Forecast**	Three months ended Mar. 31	Year ended Dec. 31
		2007	**2007**	2006
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		**128 - 135**	**148**	111
Medium crude oil		**28 - 30**	**27**	29
Heavy crude oil & bitumen		**122 - 130**	**108**	108
		278 - 295	**283**	248
Natural gas	*(mmcf/day)*	**670 - 690**	**640**	672
Total barrels of oil equivalent	*(mboe/day)*	**390 - 410**	**390**	360

Effective Royalty Rates	Three months ended March 31			
Royalties per unit of production and percentage of upstream gross revenues	**2007**		2006	
	$	**%**	**$**	**%**
Crude oil & NGL				
Light crude oil & NGL	**4.48**/*bbl*	**7**	6.33/*bbl*	9
Medium crude oil	**7.99**/*bbl*	**17**	6.46/*bbl*	17
Heavy crude oil & bitumen	**4.72**/*bbl*	**13**	3.06/*bbl*	11
Natural gas	**1.25**/*mcf*	**18**	1.64/*mcf*	20
Total	**5.63**/*boe*	**11**	6.47/*boe*	14

Upstream Revenue Mix	Three months ended March 31	
Percentage of upstream net revenues	**2007**	2006
Crude oil & NGL		
Light crude oil & NGL	**51**	43
Medium crude oil	**6**	7
Heavy crude oil & bitumen	**21**	18
	78	68
Natural gas	**22**	32
	100	100

UNIT OPERATING COSTS

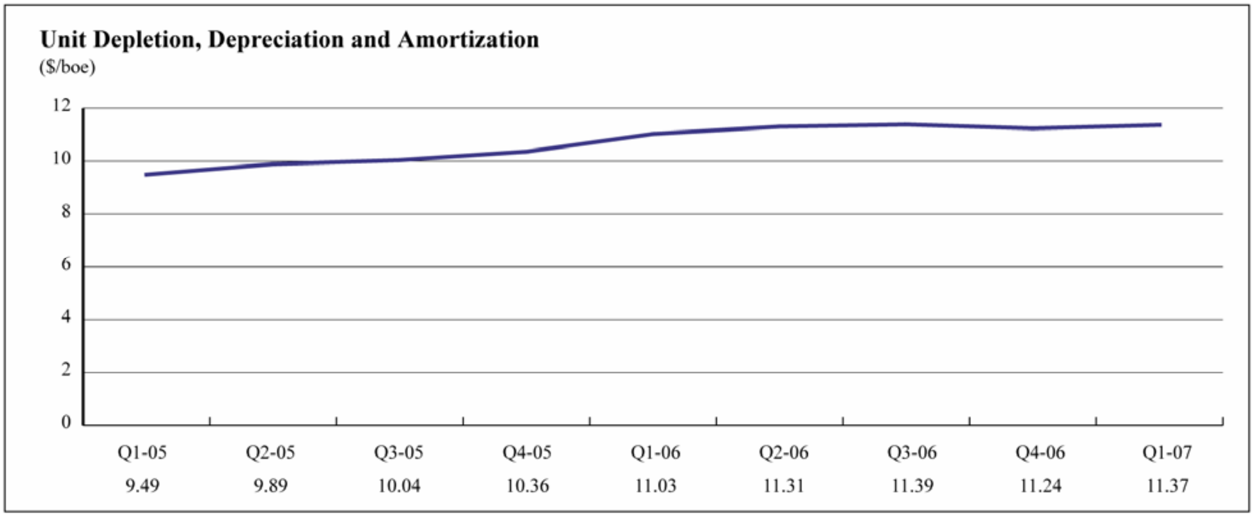


Operating costs in Western Canada averaged $10.55/boe in the first quarter of 2007 compared with $9.31/boe in the same period in 2006. Increasing operating costs in Western Canada are related to the nature of exploitation necessary to manage production from maturing fields and new more extensive but less prolific reservoirs. Western Canada operations require increasing amounts of infrastructure including more wells, more extensive pipeline systems, crude and water trucking and more extensive natural gas compression systems. These factors in turn require higher energy consumption, workovers and generally more material costs. In addition, higher levels of industry activity lead naturally to competition for resources and consequential higher service rates and unit costs. Our efforts are focused on managing rising operating costs by all means available to us. We strive to keep our infrastructure, including gas plants, crude processing plants, transportation systems, compression systems, lease access and other infrastructure fully utilized.

Operating costs at the East Coast offshore operations averaged $3.03/bbl in the first quarter of 2007 compared with $7.35/bbl in the first quarter of 2006. Unit operating costs in the first quarter of 2007 benefited from higher production volume from both White Rose and Terra Nova.

Operating costs at the South China Sea offshore operations averaged $4.28/bbl in the first quarter of 2007 compared with $3.52/bbl in the same period in 2006. Increased unit operating costs resulted from the maturing of the reservoir and the addition of liquids extraction to the operation.

DEPLETION



Depletion, depreciation and amortization ("DD&A") under the full cost method of accounting for oil and gas activities is calculated on a country-by-country basis. The DD&A rate is calculated by dividing the capital costs subject to DD&A by the proved oil and gas reserves expressed as an equivalent barrel. The resultant dollar per barrel of oil equivalent is assigned to each barrel of oil equivalent that is produced to determine the DD&A expense for the period.

Total DD&A averaged $11.37/boe in the first quarter of 2007 compared with $11.03/boe in the first quarter of 2006.

DD&A in Canada averaged $11.37/boe in the first quarter of 2007 compared with $11.26/boe in the first quarter of 2006. The increase in DD&A results primarily from higher capital. Increasing capital is due to increased drilling and associated infrastructure in Western Canada and large capital investment required to develop offshore reserves off the East Coast of Canada.

DD&A in China averaged $11.11/boe in the first quarter of 2007 compared with $8.98/boe in the first quarter of 2006. Increasing unit DD&A results from declining reserve volume due to reservoir depletion.

Operating Netbacks

	Western Canada		East Coast		International		Total	
Three months ended March 31	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Light Crude Oil *(per boe)* [(1)]								
Sales price	**$ 57.00**	$ 60.48	**$ 66.46**	$ 69.65	**$ 68.25**	$ 73.65	**$ 64.78**	$ 67.52
Royalties	**6.20**	5.46	**2.11**	3.69	**10.35**	5.96	**3.69**	4.51
Operating costs	**11.95**	11.80	**3.03**	7.35	**4.90**	3.52	**4.95**	8.15
	38.85	43.22	**61.32**	58.61	**53.00**	64.17	**56.14**	54.86
Medium Crude Oil *(per boe)* [(1)]								
Sales price	**46.19**	38.52	**-**	-	**-**	-	**46.19**	38.52
Royalties	**7.96**	6.29	**-**	-	**-**	-	**7.96**	6.29
Operating costs	**13.56**	12.51	**-**	-	**-**	-	**13.56**	12.51
	24.67	19.72	**-**	-	**-**	-	**24.67**	19.72
Heavy Crude Oil & Bitumen *(per boe)* [(1)]								
Sales price	**37.67**	26.97	**-**	-	**-**	-	**37.67**	26.97
Royalties	**4.72**	3.10	**-**	-	**-**	-	**4.72**	3.10
Operating costs	**11.84**	11.22	**-**	-	**-**	-	**11.84**	11.22
	21.11	12.65	**-**	-	**-**	-	**21.11**	12.65
Total Crude Oil *(per boe)* [(1)]								
Sales price	**42.46**	34.74	**66.46**	69.65	**68.25**	73.65	**52.46**	43.35
Royalties	**5.53**	4.08	**2.11**	3.69	**10.35**	5.96	**4.52**	3.98
Operating costs	**12.15**	11.55	**3.03**	7.35	**4.90**	3.52	**8.47**	10.52
	24.78	19.11	**61.32**	58.61	**53.00**	64.17	**39.47**	28.85
Natural Gas *(per mcfge)* [(2)]								
Sales price	**7.01**	8.05	**-**	-	**-**	-	**7.01**	8.05
Royalties	**1.44**	1.90	**-**	-	**-**	-	**1.44**	1.90
Operating costs	**1.33**	0.99	**-**	-	**-**	-	**1.33**	0.99
	4.24	5.16	**-**	-	**-**	-	**4.24**	5.16
Equivalent Unit *(per boe)* [(1)]								
Sales price	**42.31**	40.18	**66.46**	69.65	**68.25**	73.65	**49.67**	46.13
Royalties	**6.73**	7.03	**2.11**	3.69	**10.35**	5.96	**5.63**	6.46
Operating costs	**10.55**	9.31	**3.03**	7.35	**4.90**	3.52	**8.34**	8.78
	$ 25.03	$ 23.84	**$ 61.32**	$ 58.61	**$ 53.00**	$ 64.17	**$ 35.70**	$ 30.89

[(1)] *Includes associated co-products converted to boe.*
[(2)] *Includes associated co-products converted to mcfge.*

UPSTREAM CAPITAL EXPENDITURES

Capital expenditures during the first quarter of 2007 were funded primarily with internally generated cash flow.

Our 2007 Upstream Capital expenditure guidance remains unchanged from that reported in our recently filed annual MD&A.

2007 Capital Expenditure Guidance

(millions of dollars)	
Western Canada - oil & gas	**$ 1,840**
- oil sands	**330**
East Coast Canada	**290**
International	**160**
	$ 2,620

The following table summarizes our capital expenditures for the periods presented.

Capital Expenditures Summary (1)	Three months ended March 31	
(millions of dollars)	**2007**	2006
Exploration		
Western Canada	**$ 165**	$ 167
East Coast Canada and Frontier	**5**	21
International	**5**	1
	175	189
Development		
Western Canada	**388**	513
East Coast Canada	**54**	52
International	**-**	3
	442	568
	$ 617	$ 757

(1) *Excludes capitalized costs related to asset retirement obligations incurred during the period.*

During the first quarter of 2007, capital expenditures were $553 million (90%) in Western Canada, $59 million (9%) off the East Coast of Canada and $5 million (1%) offshore China, Indonesia and other international areas.

Western Canada

In Western Canada, we invested $466 million on exploration and development on conventional areas, which produce variously light, medium, heavy crude oil or natural gas throughout the Western Canada Sedimentary Basin, $272 million of which was invested on properties in Alberta, northeast British Columbia and southern Saskatchewan primarily to further develop properties with proved reserves. We drilled 234 net wells in these regions resulting in 29 oil wells and 139 natural gas wells. In the Lloydminster area of Alberta and Saskatchewan, from which the majority of our heavy crude oil is produced, we invested $139 million, again mainly to extend proved properties. We drilled 128 net wells in the Lloydminster area resulting in 115 oil wells and 10 natural gas wells. Our principal exploration program is conducted along the foothills of Alberta and British Columbia and in the deep basin region of Alberta. In the first quarter of 2007, we invested $55 million drilling in these natural gas prone areas.

During the first quarter of 2007, we drilled five net exploration wells in the foothills/deep basin regions; all were completed natural gas wells.

We spent $87 million in the oil sands areas during the first quarter of 2007, $30 million at Tucker where production is ramping up. We invested $24 million on the Sunrise project. Front-end engineering design is currently underway. We invested $33 million at our other oil sands areas principally at Saleski where we acquired additional lands, began to acquire seismic data and drilled several evaluation wells. We also drilled several stratigraphic test wells, water source and disposal evaluation wells and acquired seismic data at Caribou.

The following table discloses the number of gross and net exploration and development wells we completed during the quarter ended March 31, 2007 and the same quarter in 2006. The data indicates that 89% of the exploration wells and 96% of the development wells we drilled resulted in wells capable of commercial production.

Western Canada Wells Drilled (1) (2)		Three months ended March 31			
		2007		2006	
		Gross	**Net**	Gross	Net
Exploration	Oil	**20**	**20**	22	22
	Gas	**65**	**56**	158	86
	Dry	**9**	**9**	15	14
		94	**85**	195	122
Development	Oil	**138**	**130**	110	103
	Gas	**168**	**137**	225	193
	Dry	**10**	**10**	9	9
		316	**277**	344	305
Total		**410**	**362**	539	427

(1) *Excludes stratigraphic test wells.*
(2) *Includes non-operated wells.*

Off the East Coast of Canada

During the first quarter of 2007 capital expenditures in the region off the East Coast of Canada totalled $59 million. We are currently drilling the seventh production well at the White Rose oil field and a delineation well in the south portion of the Far East flank at the Terra Nova oil field. Exploration expenditures in the East Coast offshore areas were minimal during the first quarter of 2007 as drilling locations were being evaluated.

International

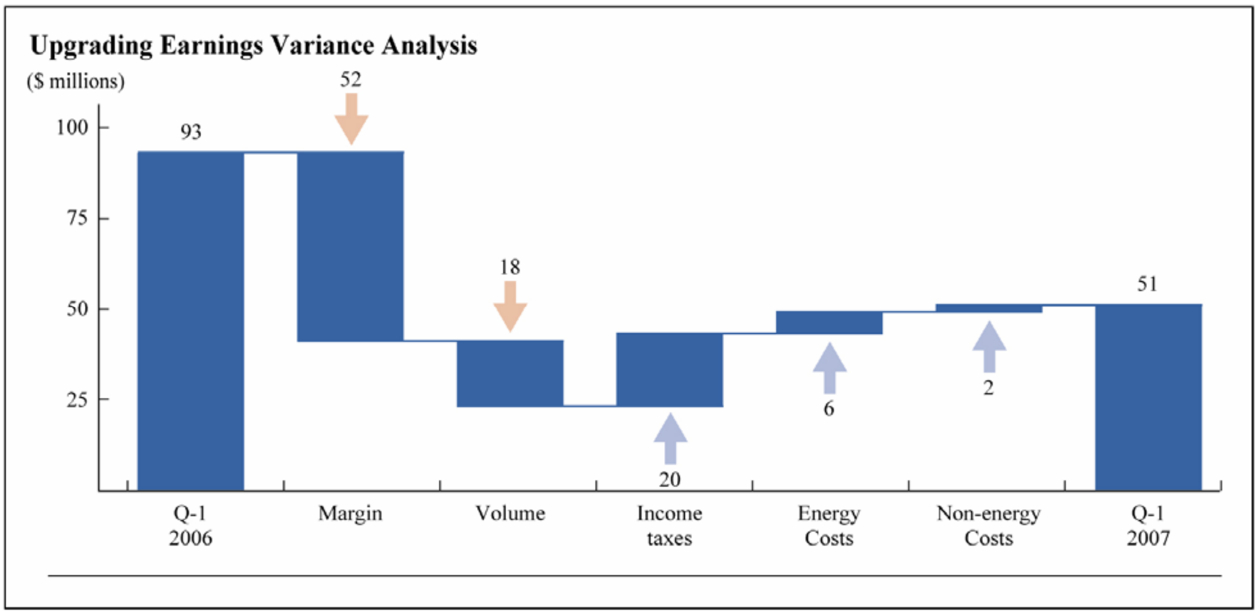
During the first quarter of 2007 we invested $5 million on international exploration for drilling location evaluations for the South and East China Seas and on the East Bawean II exploration block in the Java Sea.

4.2 MIDSTREAM

Upgrading Earnings Summary

(millions of dollars, except where indicated)		Three months ended March 31 2007	2006
Gross margin		**$ 138**	$ 208
Operating costs		**58**	66
Other recoveries		**(1)**	(1)
Depreciation and amortization		**6**	6
Income taxes		**24**	44
Earnings		**$ 51**	$ 93
Selected operating data:			
Upgrader throughput [(1)]	*(mbbls/day)*	**69.0**	71.3
Synthetic crude oil sales	*(mbbls/day)*	**57.8**	63.4
Upgrading differential	*($/bbl)*	**$ 24.11**	$ 34.82
Unit margin	*($/bbl)*	**$ 26.44**	$ 36.38
Unit operating cost [(2)]	*($/bbl)*	**$ 9.30**	$ 10.24

[(1)] *Throughput includes diluent returned to the field.*
[(2)] *Based on throughput.*



Upgrading earnings in the first quarter of 2007 were $51 million, a decrease of $42 million from the first quarter of 2006 due primarily to reduced light to heavy oil price differential. Upgrader throughput in the first quarter of 2007 was 3% lower than the comparable quarter in 2006 as a result of some unexpected plant outages. Lower upgrader operating costs during the first quarter of 2007, primarily natural gas and other energy related costs, partially offset the effect of the narrow upgrading differential.

Infrastructure and Marketing Earnings Summary	Three months ended March 31	
(millions of dollars, except where indicated)	**2007**	2006
Gross margin - pipeline	**$ 26**	$ 26
- other infrastructure and marketing	**72**	68
	98	94
Other expenses	**4**	2
Depreciation and amortization	**7**	6
Income taxes	**27**	29
Earnings	**$ 60**	$ 57
Selected operating data:		
Aggregate pipeline throughput *(mbbls/day)*	**493**	500

Infrastructure and marketing earnings in the first quarter of 2007 were marginally higher compared with the first quarter of 2006.

MIDSTREAM CAPITAL EXPENDITURES

Midstream capital expenditures totalled $84 million in the first three months of 2007: $48 million at the Lloydminster Upgrader, primarily for front-end engineering design for a proposed expansion, a small debottleneck project and reliability projects. The remaining $36 million was spent on a pipeline extension between Lloydminster and Hardisty, Alberta.

4.3 REFINED PRODUCTS

Refined Products Earnings Summary		Three months ended March 31	
(millions of dollars, except where indicated)		**2007**	2006
Gross margin - fuel sales		**$ 42**	$ 22
- ancillary sales		**9**	8
- asphalt sales		**13**	21
		64	51
Operating and other expenses		**18**	16
Depreciation and amortization		**16**	10
Income taxes		**10**	9
Earnings		**$ 20**	$ 16
Selected operating data:			
Number of fuel outlets		**506**	514
Light oil sales	*(million litres/day)*	**8.9**	8.6
Light oil retail sales per outlet	*(thousand litres/day)*	**12.9**	12.9
Prince George refinery throughput	*(mbbls/day)*	**11.1**	9.3
Asphalt sales	*(mbbls/day)*	**17.3**	17.7
Lloydminster refinery throughput	*(mbbls/day)*	**24.7**	27.1
Ethanol production	*(thousand litres/day)*	**318.1**	26.1

Refined Products earnings in the first quarter of 2007 increased by $4 million compared with the first quarter of 2006 primarily due to increased fuel margins partially offset by higher depreciation created by the start up of the Lloydminster Ethanol Plant and lower gross margin from the asphalt business due to higher heavy crude oil feedstock costs.

REFINED PRODUCTS CAPITAL EXPENDITURES

Refined Products capital expenditures totalled $40 million during the first quarter of 2007. The Minnedosa ethanol plant currently under construction accounted for $27 million, $6 million for marketing location upgrades and construction, $4 million for debottleneck and upgrade projects at the Lloydminster asphalt refinery and the Prince George refinery.

4.4 CORPORATE

Corporate Summary	Three months ended March 31	
(millions of dollars) income (expense)	**2007**	2006
Intersegment eliminations - net	**$ (25)**	$ 9
Administration expenses	**(11)**	(4)
Stock-based compensation	**(21)**	(70)
Accretion	**(1)**	-
Other - net	**(5)**	(4)
Depreciation and amortization	**(5)**	(6)
Interest on debt	**(24)**	(38)
Interest capitalized	**3**	11
Foreign exchange - realized	**6**	27
Foreign exchange - unrealized	**(5)**	(22)
Income taxes	**27**	43
Earnings (loss)	**$ (61)**	$ (54)

Foreign Exchange Summary	Three months ended March 31	
(millions of dollars)	**2007**	2006
(Gain) loss on translation of U.S. dollar denominated long-term debt		
Realized	**$ -**	$ (31)
Unrealized	**(14)**	30
	(14)	(1)
Cross currency swaps	**4**	(1)
Other (gains) losses	**9**	(3)
	$ (1)	$ (5)
U.S./Canadian dollar exchange rates:		
At beginning of period	**U.S. $0.858**	U.S. $0.858
At end of period	**U.S. $0.867**	U.S. $0.857

CORPORATE CAPITAL EXPENDITURES

Corporate capital expenditures totaled $5 million in the first three months of 2007 primarily for various office and information system upgrades.

CONSOLIDATED INCOME TAXES

During the first quarter of 2007, consolidated income taxes consisted of $72 million of current taxes and $225 million of future taxes compared with current taxes of $204 million and future taxes of $48 million in the same period of 2006.

The decrease in current taxes and increase in future taxes in the first quarter of 2007 compared with the first quarter of 2006 was due to the deferral of White Rose income.

Quarterly Financial Summary

	Three months ended							
	March 31	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30
(millions of dollars, except per share amounts and ratios)	**2007**	2006	2006	2006	2006	2005	2005	2005
Sales and operating revenues, net of royalties	**$ 3,244**	$ 3,084	$ 3,436	$ 3,040	$ 3,104	$ 3,207	$ 2,594	$ 2,350
Segmented earnings								
Upstream	**$ 580**	$ 453	$ 608	$ 822	$ 412	$ 533	$ 445	$ 307
Midstream	**111**	105	87	140	150	135	61	130
Refined Products	**20**	10	28	52	16	17	27	20
Corporate and eliminations	**(61)**	(26)	(41)	(36)	(54)	(16)	23	(63)
Net earnings	**$ 650**	$ 542	$ 682	$ 978	$ 524	$ 669	$ 556	$ 394
Per share - Basic and diluted	**$ 1.53**	$ 1.28	$ 1.61	$ 2.31	$ 1.24	$ 1.58	$ 1.31	$ 0.93
Cash flow from operations	**1,324**	1,207	1,224	1,103	967	1,197	944	828
Per share - Basic and diluted	**3.12**	2.84	2.88	2.60	2.28	2.82	2.23	1.95
Ordinary quarterly dividend per common share	**0.50**	0.50	0.50	0.25	0.25	0.25	0.14	0.14
Special dividend per common share	**0.50**	-	-	-	-	1.00	-	-
Total assets	**17,781**	17,933	17,324	16,328	15,855	15,716	14,670	14,055
Total long-term debt including current portion	**1,527**	1,611	1,722	1,722	1,838	1,886	1,896	2,192
Return on equity [(1)] *(percent)*	**32.1**	31.8	34.2	34.8	29.6	29.2	22.9	20.2
Return on average capital employed [(1)] *(percent)*	**27.3**	27.0	28.7	28.2	23.2	22.8	17.9	15.3

[(1)] *Calculated for the 12 months ended for the dates shown.*

4.5 SENSITIVITY ANALYSIS

The following table indicates the relative annual effect of changes in certain key variables on our pre-tax cash flow and net earnings. The analysis is based on business conditions and production volumes during the first quarter of 2007. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant. While these sensitivities are applicable for the period and magnitude of changes on which they are based, they may not be applicable in other periods, under other economic circumstances or greater magnitudes of change.

Sensitivity Analysis	2007 First Quarter Average	Increase	Effect on Pre-tax Cash Flow		Effect on Net Earnings	
			($ millions)	*($/share)* [(5)]	*($ millions)*	*($/share)* [(5)]
Upstream and Midstream						
WTI benchmark crude oil price	$ 58.16	*U.S. $1.00/bbl*	107	0.25	73	0.17
NYMEX benchmark natural gas price [(1)]	$ 6.77	*U.S. $0.20/mmbtu*	35	0.08	24	0.06
WTI/Lloyd crude blend differential [(2)]	$ 17.32	*U.S. $1.00/bbl*	(31)	(0.07)	(21)	(0.05)
Exchange rate (U.S. $ per Cdn $) [(3)]	$ 0.85	*U.S. $0.01*	(74)	(0.17)	(55)	(0.13)
Refined Products						
Light oil margins	$ 0.04	*Cdn $0.005/litre*	16	0.04	10	0.02
Asphalt margins	$ 7.88	*Cdn $1.00/bbl*	6	0.01	4	0.01
Consolidated						
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	$ 0.867 [(4)]	*U.S. $0.01*			9	0.02

[(1)] Includes decrease in earnings related to natural gas consumption.
[(2)] Includes impact of upstream and upgrading operations only.
[(3)] Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items.
[(4)] U.S./Canadian dollar exchange rate at March 31, 2007.
[(5)] Based on 424.3 million common shares outstanding as of March 31, 2007.

5.0 LIQUIDITY AND CAPITAL RESOURCES

During the first quarter of 2007, cash flow from operating activities financed all of our capital requirements and dividend payment. At March 31, 2007 we had $1.4 billion in unused committed credit facilities.

Cash Flow Summary	Three months ended March 31	
(millions of dollars, except ratios)	**2007**	2006
Cash flow - operating activities	**$ 672**	$ 1,131
- financing activities	**$ (222)**	$ (439)
- investing activities	**$ (892)**	$ (860)
Financial Ratios		
Debt to capital employed *(percent)*	**14.1**	19.3
Corporate reinvestment ratio *(percent)* [(1) (2)]	**63**	80

[(1)] Calculated for the 12 months ended for the dates shown.
[(2)] Reinvestment ratio is based on net capital expenditures including corporate acquisitions.

5.1 OPERATING ACTIVITIES

In the first quarter of 2007, cash generated from operating activities amounted to $672 million compared with $1.1 billion in the first quarter of 2006. Lower cash flow from operating activities was primarily due to a decrease in non-cash working capital resulting primarily from payment of cash income taxes payable.

5.2 FINANCING ACTIVITIES

In the first quarter of 2007, cash used in financing activities amounted to $222 million compared with $439 million in the first quarter of 2006. During the first quarter of 2007, cash provided by a change in non-cash working capital associated with financing activities, offset by higher dividends, primarily resulted in a lower use of cash compared with the first quarter of 2006. The change in non-cash working capital mainly related to an increase in dividends payable, due to the special dividend of $0.50 per common share declared in February 2007. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

5.3 INVESTING ACTIVITIES

In the first quarter of 2007, cash used in investing activities amounted to $892 million compared with $860 million in the first quarter of 2006. Cash invested in both periods was used primarily for capital expenditures.

5.4 SOURCES OF CAPITAL

We are currently able to fund our capital programs principally by cash provided from operating activities. We also maintain access to sufficient capital via capital debt markets commensurate with the strength of our balance sheet and continually examine our options with respect to sources of long and short-term capital resources. In addition, from time to time we engage in hedging a portion of our revenue to protect cash flow.

Working capital is the amount by which current assets exceed current liabilities. At March 31, 2007, our working capital deficiency was $341 million compared with $495 million at December 31, 2006. These working capital deficits are primarily the result of accounts payable related to capital expenditures for exploration and development. Settlement of these current liabilities is funded by cash provided by operating activities and, to the extent necessary, by bank borrowings. This position is a common characteristic of the oil and gas industry which, by the nature of its business, spends large amounts of capital.

(millions of dollars)	March 31 **2007**	Dec. 31 2006	Change	
Current assets				
Cash and cash equivalents	**$ -**	$ 442	$ (442)	Tax payment
Accounts receivable	**1,202**	1,284	(82)	Lower gas prices
Income taxes receivable	**82**	-	82	Tax assessment recoverable
Inventories	**420**	428	(8)	
Prepaid expenses	**20**	25	(5)	
	1,724	2,179	(455)	
Current liabilities				
Bank operating loans	**83**	-	(83)	Outstanding cheques
Accounts payable	**1,110**	1,268	158	Lower capital and operating cost accruals
Accrued interest payable	**28**	27	(1)	
Income taxes payable	**-**	615	615	Tax payment made
Other accrued liabilities	**844**	664	(180)	Special dividend declared in February 2007
Long-term debt due within one year	**-**	100	100	Payment of medium-term notes
	2,065	2,674	609	
Working capital	**$ (341)**	$ (495)	$ 154	

Sources and Uses of Cash

(millions of dollars)	Three months ended March 31 2007	Year ended December 31 2006
Cash sourced		
Cash flow from operations [1]	**$ 1,324**	$ 4,501
Debt issue	**518**	1,226
Asset sales	**-**	34
Proceeds from exercise of stock options	**1**	3
	1,843	5,764
Cash used		
Capital expenditures	**734**	3,171
Debt repayment	**535**	1,493
Special dividend on common shares	**212**	-
Ordinary dividends on common shares	**212**	636
Settlement of asset retirement obligations	**14**	36
Settlement of cross currency swap	**-**	47
Other	**2**	13
	1,709	5,396
Net cash	**134**	368
Decrease in non-cash working capital	**(576)**	(94)
Increase (decrease) in cash and cash equivalents	**(442)**	274
Cash and cash equivalents - beginning of period	**442**	168
Cash and cash equivalents - end of period	**$ -**	$ 442

[1] *Cash flow from operations represents net earnings plus items not affecting cash, which include accretion, depletion, depreciation and amortization, future income taxes and foreign exchange.*

Capital Structure

(millions of dollars)	March 31, 2007 Outstanding (U.S. $)	(Cdn $)	Available (Cdn $)
Short-term bank debt	$ -	$ 5	$ 185
Long-term bank debt			
Syndicated credit facility	-	-	1,020
Bilateral credit facilities	-	-	150
Medium-term notes (1)	-	200	
Capital securities	225	259	
U.S. public notes	900	1,038	
	1,125	1,502	1,355
Fair value adjustment (1)	-	4	
Debt issue costs (2)	-	(14)	
Unwound interest rate swaps (3)	-	40	
Total short-term and long-term debt	$ 1,125	$ 1,532	$ 1,355
Common shares, retained earnings and accumulated other comprehensive income		$ 9,837	

(1) *The carrying value of the medium-term notes has been adjusted to fair value to meet the accounting requirements for a fair value hedge. Refer to Notes 3 and 11 to the Consolidated Financial Statements.*
(2) *Debt issue costs have been reclassified to long-term debt with the adoption of financial instruments. Previously these deferred costs were included in other assets. Refer to Notes 3 and 6 to the Consolidated Financial Statements.*
(3) *The unamortized portion of the gain on previously unwound interest rate swaps that would be designated as fair value hedges is required to be included in the carrying value of long-term debt with the adoption of financial instruments. Refer to Notes 3 and 6 to the Consolidated Financial Statements.*

At March 31, 2007, we had unused committed long and short-term borrowing credit facilities totalling $1.4 billion. A total of $30 million of our borrowing credit facilities were used in support of outstanding letters of credit and an additional $68 million of letters of credit were outstanding at March 31, 2007 and supported by dedicated letters of credit lines.

We currently have a shelf prospectus dated September 21, 2006 that enables us to offer up to U.S. $1.0 billion of debt securities in the United States until October 21, 2008. During the 25 months that the prospectus is effective, debt securities may be offered in amounts, at prices and on terms to be determined based on market conditions at the time of sale. As of the date of this Management's Discussion and Analysis, no debt securities had been issued under this shelf prospectus.

5.5 CREDIT RATINGS

Our credit ratings are available in our recently filed Annual Information Form at www.sedar.com.

5.6 CONTRACTUAL OBLIGATIONS AND COMMERCIAL COMMITMENTS

Refer to Husky's 2006 annual Management's Discussion and Analysis under the caption "Cash Requirements," which summarizes contractual obligations and commercial commitments. There has been no material change in these amounts as at March 31, 2007.

5.7 OFF BALANCE SHEET ARRANGEMENTS

We do not utilize off balance sheet arrangements with unconsolidated entities to enhance perceived liquidity.

We engage, in the ordinary course of business, in the securitization of accounts receivable. At March 31, 2007, we had no accounts receivable sold under the securitization program. The securitization program permits the sale of a maximum $350 million of accounts receivable on a revolving basis. The accounts receivable are sold to an unrelated third party and in accordance with the agreement we must provide a loss reserve to replace defaulted receivables. The securitization agreement expires on January 31, 2009.

The securitization program provides us with cost effective short-term funding for general corporate use. We account for these securitizations as asset sales. In the event the program is terminated our liquidity would not be materially reduced.

5.8 Transactions with Related Parties

We did not have any significant transactions with related parties during the first three months of 2007 or during the year ended December 31, 2006.

5.9 Significant Customers

We did not have any customers that constituted more than 10% of total sales and operating revenues during the first three months of 2007.

6.0 Risks and Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks see our Annual Information Form recently filed on the Canadian Securities Administrator's web site, www.sedar.com, the Securities Exchange Commission's web site, www.sec.gov or our web site www.huskyenergy.ca.

6.1 Financial Risks

Our financial risks are largely related to commodity prices, exchange rates, interest rates, credit risk, changes in fiscal policy related to royalties and taxes and others. From time to time, we use financial and derivative instruments to manage our exposure to these risks.

Power Consumption

At March 31, 2007, we had a cash flow hedge for power consumption as follows:

(millions of dollars, except where indicated)	Notional Volumes *(MW)*	Term	Price	Fair Value
Fixed price purchase	20.0	Apr. to Jun. 2007	$ 63.63/MWh	$ (0.4)

Interest Rate Risk Management

In the first three months of 2007, interest rate risk management activities resulted in a decrease to interest expense of $1 million.

Cross currency swaps resulted in an addition to interest expense of $1 million in the first three months of 2007.

Husky has interest rate swaps on $200 million of long-term debt effective February 8, 2002 whereby 6.95% was swapped for CDOR + 175 bps until July 14, 2009. During the first three months of 2007, these swaps resulted in an offset to interest expense amounting to $1 million.

The amortization of previous interest rate swap terminations resulted in an additional $1 million offset to interest expense in the first three months of 2007.

Foreign Currency Risk Management

At March 31, 2007, we had the following cross currency debt swaps in place:

- U.S. $150 million at 6.25% swapped at $1.41 to $212 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $90 million at 5.65 % until June 15, 2012.

- U.S. $50 million at 6.25% swapped at $1.17 to $59 million at 5.67% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.17 to $88 million at 5.61% until June 15, 2012

At March 31, 2007 the cost of a U.S. dollar in Canadian currency was $1.1529.

Our results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of our revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. The majority of our expenditures are in Canadian dollars. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities.

In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in Husky's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as in the related interest expense. At March 31, 2007, 86% or $1.3 billion of our long-term debt was denominated in U.S. dollars. The percentage of our long-term debt exposed to the Cdn/U.S. exchange rate decreases to 60% when cross currency swaps are considered.

7.0 Critical Accounting Estimates

Certain of our accounting policies require that we make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. For a discussion about those accounting policies, please refer to our Management's Discussion and Analysis for the year ended December 31, 2006 available at www.sedar.com.

8.0 Changes in Accounting Policies

Financial Instruments and Hedging Activities

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3855, "Financial Instruments - Recognition and Measurement," section 3865, "Hedges," section 1530, "Comprehensive Income" and section 3861, "Financial Instruments - Disclosure and Presentation." These standards have been adopted prospectively. See Note 3a) to the Consolidated Financial Statements.

Accounting Changes

In July 2006, the AcSB issued a revised CICA section 1506, "Accounting Changes." These amendments were made to harmonize section 1506 with current IFRS. The changes covered by this section include changes in accounting policy, changes in accounting estimates and correction of errors. Under CICA section 1506, voluntary changes in accounting policy are only permitted if they result in financial statements that provide more reliable and relevant information. When a change in accounting policy is made, this change is applied retrospectively unless impractical. Changes in accounting estimates are generally applied prospectively and material prior period errors are corrected retrospectively. This section also outlines additional disclosure requirements when accounting changes are applied including justification for voluntary changes, complete description of the policy, primary source of GAAP and detailed effect on financial statement line items. CICA section 1506 is effective for fiscal years beginning on or after January 1, 2007.

9.0 OUTSTANDING SHARE DATA

(in thousands, except per share amounts)		Three months ended March 31 2007	Year ended December 31 2006
Share price (1)	High	**$ 81.89**	$ 83.00
	Low	**$ 70.80**	$ 58.00
	Close at end of period	**$ 80.66**	$ 78.04
Average daily trading volume		**590**	605
Weighted average number of common shares outstanding			
	Basic and diluted	**424,285**	424,206
Issued and outstanding at end of period (2)			
Number of common shares		**424,306**	424,269
Number of stock options		**5,285**	5,828
Number of stock options exercisable		**1,938**	2,232

(1) *Trading in the common shares of Husky Energy Inc. ("HSE") commenced on the Toronto Stock Exchange on August 28, 2000. The Company is represented in the S&P/TSX Composite, S&P/TSX Canadian Energy Sector and in the S&P/TSX 60 indices.*

(2) *There were no significant issuances of common shares, stock options or any other securities convertible into, or exercisable or exchangeable for common shares during the period from March 31, 2007 to April 10, 2007. During this period, six thousand stock options were exercised for shares and 263 thousand stock options were surrendered for cash. At April 10, 2007, the Company had 424,312 thousand common shares outstanding and there were 5,016 thousand stock options outstanding, of which 1,670 thousand were exercisable.*

10.0 NON-GAAP MEASURES

DISCLOSURE OF CASH FLOW FROM OPERATIONS

Management's Discussion and Analysis contains the term "cash flow from operations," which should not be considered an alternative to, or more meaningful than "cash flow - operating activities" as determined in accordance with generally accepted accounting principles as an indicator of our financial performance. Our determination of cash flow from operations may not be comparable to that reported by other companies. Cash flow from operations equals net earnings plus items not affecting cash which include accretion, depletion, depreciation and amortization, future income taxes, foreign exchange and other non-cash items.

The following table shows the reconciliation of cash flow from operations to cash flow - operating activities for the periods noted:

(millions of dollars)		Three months ended March 31 2007	Year ended December 31 2006
Non-GAAP	Cash flow from operations	**$ 1,324**	$ 4,501
	Settlement of asset retirement obligations	**(14)**	(36)
	Change in non-cash working capital	**(638)**	544
GAAP	Cash flow - operating activities	**$ 672**	$ 5,009

11.0 READER ADVISORIES

This MD&A should be read in conjunction with the Consolidated Financial Statements and related Notes. Readers are encouraged to refer to Husky's MD&A and Consolidated Financial Statements and 2006 Annual Information Form filed in 2007 with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and at www.huskyenergy.ca.

Use of Pronouns and Other Terms Denoting Husky

In this MD&A the pronouns "we," "our" and "us" and the terms "Husky" and "the Company" denote the corporate entity Husky Energy Inc. and its subsidiaries on a consolidated basis.

Standard Comparisons in this Document

Unless otherwise indicated, the discussions in this MD&A with respect to results for the three months ended March 31, 2007 are compared with results for the three months ended March 31, 2006. Discussions with respect to Husky's financial position as at March 31, 2007 are compared with its financial position at December 31, 2006.

Additional Reader Guidance

- The Consolidated Financial Statements and comparative financial information included in this Interim Report have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").
- All dollar amounts are in millions of Canadian dollars, unless otherwise indicated.
- Unless otherwise indicated, all production volumes quoted are gross, which represent the Company's working interest share before royalties.
- Prices quoted include or exclude the effect of hedging as indicated.

Cautionary Note Required by National Instrument 51-101

The Company uses the terms barrels of oil equivalent ("boe") and thousand cubic feet of gas equivalent ("mcfge"), which are calculated on an energy equivalence basis whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. Readers are cautioned that the terms boe and mcfge may be misleading, particularly if used in isolation. This measure is primarily applicable at the burner tip and does not represent value equivalence at the well head.

Husky's disclosure of reserves data and other oil and gas information is made in reliance on an exemption granted to Husky by Canadian securities regulatory authorities, which permits Husky to provide disclosure required by and consistent with those of the United States Securities and Exchange Commission and the Financial Accounting Standards Board in the United States in place of much of the disclosure expected by National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities." Please refer to "Disclosure of Exemption Under National Instrument 51-101" on page 2 of our Annual Information Form for the year ended December 31, 2006 filed with securities regulatory authorities for further information.

Terms and abbreviations

bbls	*barrels*
bps	*basis points*
mbbls	*thousand barrels*
mbbls/day	*thousand barrels per day*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
mmcf/day	*million cubic feet per day*
bcf	*billion cubic feet*
tcf	*trillion cubic feet*
boe	*barrels of oil equivalent*
mboe	*thousand barrels of oil equivalent*
mboe/day	*thousand barrels of oil equivalent per day*
mmboe	*million barrels of oil equivalent*
mcfge	*thousand cubic feet of gas equivalent*
GJ	*gigajoule*
mmbtu	*million British Thermal Units*
mmlt	*million long tons*
MW	*megawatt*
MWh	*megawatt-hour*
NGL	*natural gas liquids*
WTI	*West Texas Intermediate*
NYMEX	*New York Mercantile Exchange*
NIT	*NOVA Inventory Transfer*
LIBOR	*London Interbank Offered Rate*
CDOR	*Certificate of Deposit Offered Rate*

SEDAR	*System for Electronic Document Analysis and Retrieval*
FPSO	*Floating production, storage and offloading vessel*
FEED	*Front-end engineering design*
OPEC	*Organization of Petroleum Exporting Countries*
WCSB	*Western Canada Sedimentary Basin*
SAGD	*Steam-assisted gravity drainage*
Bitumen	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. It is more viscous than 10 degrees API*
Coalbed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
Carbonate	*Sedimentary rock primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite) which forms many petroleum reservoirs*
Petroleum in Place	*The total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. Oil in place, gas in place and bitumen in place are defined in the same manner*
Surfactant	*A substance that tends to reduce the surface tension of a liquid in which it is dissolved*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
Front-end Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
NOVA Inventory Transfer	*Exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline*
Hectare	*One hectare is equal to 2.47 acres*
Feedstock	*Raw materials which are processed into petroleum products*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Gross/Net Acres/Wells	*Gross refers to the total number of acres/wells in which an interest is owned. Net refers to the sum of the fractional working interests owned by a company*
Initial Reserves	*Remaining reserves plus cumulative production*
Possible Reserves	*Are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves*
Discovered Resource	*Are those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered resources are divided into economic and uneconomic categories, with the estimated future recoverable portion classified as reserves and contingent resources, respectively*
Contingent Resource	*Are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but not currently economic*
Dated Brent	*Prices which are dated less than 15 days prior to loading for delivery*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
Capital Employed	*Short- and long-term debt and shareholders' equity*
Capital Expenditures	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Equity	*Shares and retained earnings*
Total Debt	*Long-term debt including current portion and bank operating loans*

12.0 FORWARD-LOOKING STATEMENTS

Certain statements in this release and Interim Report are forward-looking statements or information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The Company is hereby providing cautionary statements identifying important factors that could cause the Company's actual results to differ materially from those projected in these forward-looking statements. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result," "are expected to," "will continue," "is anticipated," "estimated," "intend," "plan," "projection," "could," "vision," "goals," "objective" and "outlook") are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. In particular, forward-looking statements include: our general strategic plans, our production guidance, our White Rose oil field drilling, development and production plans, our production plans for the Tucker in-situ oil sands project, our Sunrise oil sands project design schedule, the schedule and expected results of our offshore China geophysical and drilling programs, our Minnedosa plant commissioning schedule, the schedule and our plans for expanding our heavy crude oil mainline, our Lloydminster Upgrader debottlenecking plans and expected results and schedule of our Lloydminster Upgrader expansion design plans. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this release and Interim Report. Among the key factors that have a direct bearing on our results of operations are the nature of our involvement in the business of exploration for, and development and production of crude oil and natural gas reserves and the fluctuation of the exchange rates between the Canadian and United States dollar.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. The risks, uncertainties and other factors, many of which are beyond our control, that could influence actual results include, but are not limited to

- *the prices we receive for our crude and natural gas production;*
- *demand for our products and our cost of operations;*

- *our ability to replace our proved oil and gas reserves in a cost effective manner;*
- *competitive actions of other companies, including increased competition from other oil and gas companies;*
- *business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting us or other parties whose operations or assets directly or indirectly affect us and that may or may not be financially recoverable;*
- *foreign exchange risk;*
- *actions by governmental authorities, including changes in environmental and other regulations that may impose operating costs or restrictions in areas where we operate; and*
- *the accuracy of our reserve estimates and estimated production levels.*

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable law, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of dollars, except share data)	**March 31 2007**	December 31 2006
	(unaudited)	
Assets		
Current assets		
Cash and cash equivalents	**$ -**	$ 442
Accounts receivable	**1,284**	1,284
Inventories	**420**	428
Prepaid expenses	**20**	25
	1,724	2,179
Property, plant and equipment - (full cost accounting)	**26,292**	25,552
Less accumulated depletion, depreciation and amortization	**10,435**	10,002
	15,857	15,550
Goodwill	**160**	160
Other assets	**40**	44
	$ 17,781	$ 17,933
Liabilities and Shareholders' Equity		
Current liabilities		
Bank operating loans *(note 5)*	**$ 83**	$ -
Accounts payable and accrued liabilities	**1,982**	2,574
Long-term debt due within one year *(note 6)*	**-**	100
	2,065	2,674
Long-term debt *(note 6)*	**1,527**	1,511
Other long-term liabilities *(note 7)*	**761**	756
Future income taxes	**3,591**	3,372
Commitments and contingencies *(note 8)*		
Shareholders' equity		
Common shares *(note 9)*	**3,536**	3,533
Retained earnings	**6,317**	6,087
Accumulated other comprehensive income	**(16)**	-
	9,837	9,620
	$ 17,781	$ 17,933
Common shares outstanding *(millions) (note 9)*	**424.3**	424.3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Earnings and Comprehensive Income

(millions of dollars, except share data) (unaudited)	Three months ended March 31 **2007**	2006
Sales and operating revenues, net of royalties	**$ 3,244**	$ 3,104
Costs and expenses		
Cost of sales and operating expenses	**1,779**	1,827
Selling and administration expenses	**38**	27
Stock-based compensation	**21**	70
Depletion, depreciation and amortization	**433**	379
Interest - net *(note 6)*	**21**	27
Foreign exchange *(note 6)*	**(1)**	(5)
Other - net	**6**	3
	2,297	2,328
Earnings before income taxes	**947**	776
Income taxes		
Current	**72**	204
Future	**225**	48
	297	252
Net earnings	**650**	524
Other comprehensive income, net of tax *(note 3)*	**2**	-
Comprehensive income *(note 3)*	**$ 652**	$ 524
Earnings per share		
Basic and diluted	**$ 1.53**	$ 1.24
Weighted average number of common shares outstanding *(millions)*		
Basic and diluted	**424.3**	424.1

Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

(millions of dollars) (unaudited)	Three months ended March 31 **2007**	2006
Retained earnings, beginning of period	**$ 6,087**	$ 3,997
Net earnings	**650**	524
Dividends on common shares - ordinary	**(212)**	(106)
- special	**(212)**	-
Adoption of financial instruments *(notes 3, 11)*	**4**	-
Retained earnings, end of period	**$ 6,317**	$ 4,415
Accumulated other comprehensive income, beginning of period	**$ -**	$ -
Adoption of financial instruments *(notes 3, 11)*	**(18)**	-
Other comprehensive income, net of tax *(note 3)*	**2**	-
Accumulated other comprehensive income, end of period	**$ (16)**	$ -

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

	Three months ended March 31	
(millions of dollars) (unaudited)	**2007**	2006
Operating activities		
Net earnings	**$ 650**	$ 524
Items not affecting cash		
Accretion *(note 7)*	**12**	9
Depletion, depreciation and amortization	**433**	379
Future income taxes	**225**	48
Foreign exchange	**(10)**	(1)
Other	**14**	8
Settlement of asset retirement obligations	**(14)**	(8)
Change in non-cash working capital *(note 4)*	**(638)**	172
Cash flow - operating activities	**672**	1,131
Financing activities		
Bank operating loans financing - net	**83**	132
Long-term debt issue	**435**	975
Long-term debt repayment	**(535)**	(1,022)
Proceeds from exercise of stock options	**1**	1
Dividends on common shares	**(424)**	(106)
Change in non-cash working capital *(note 4)*	**218**	(419)
Cash flow - financing activities	**(222)**	(439)
Available for investing	**450**	692
Investing activities		
Capital expenditures	**(734)**	(860)
Asset sales	**-**	32
Other	**(2)**	(1)
Change in non-cash working capital *(note 4)*	**(156)**	(31)
Cash flow - investing activities	**(892)**	(860)
Decrease in cash and cash equivalents	**(442)**	(168)
Cash and cash equivalents, beginning of period	**442**	168
Cash and cash equivalents, end of period	**$ -**	$ -

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Notes to the Consolidated Financial Statements

Three months ended March 31, 2007 *(unaudited)*

Except where indicated, all dollar amounts are in millions.

Note 1 Segmented Financial Information

	Upstream		Midstream				Refined Products		Corporate and Eliminations [1]		Total	
			Upgrading		Infrastructure and Marketing							
	2007	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Three months ended March 31												
Sales and operating revenues, net of royalties	**$ 1,565**	$ 1,287	**$ 359**	$ 405	**$ 2,555**	$ 2,464	**$ 618**	$ 546	**$ (1,853)**	$ (1,598)	**$ 3,244**	$ 3,104
Costs and expenses												
Operating, cost of sales, selling and general	**323**	311	**278**	262	**2,461**	2,372	**572**	511	**(1,790)**	(1,529)	**1,844**	1,927
Depletion, depreciation and amortization	**399**	351	**6**	6	**7**	6	**16**	10	**5**	6	**433**	379
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**21**	27	**21**	27
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(1)**	(5)	**(1)**	(5)
	722	662	**284**	268	**2,468**	2,378	**588**	521	**(1,765)**	(1,501)	**2,297**	2,328
Earnings (loss) before income taxes	**843**	625	**75**	137	**87**	86	**30**	25	**(88)**	(97)	**947**	776
Current income taxes	**22**	143	**1**	24	**16**	19	**8**	9	**25**	9	**72**	204
Future income taxes	**241**	70	**23**	20	**11**	10	**2**	-	**(52)**	(52)	**225**	48
Net earnings (loss)	**$ 580**	$ 412	**$ 51**	$ 93	**$ 60**	$ 57	**$ 20**	$ 16	**$ (61)**	$ (54)	**$ 650**	$ 524
Capital employed - As at March 31	**$10,069**	$ 8,815	**$ 826**	$ 670	**$ 667**	$ 342	**$ 684**	$ 527	**$ (799)**	$ (443)	**$ 11,447**	$ 9,911
Capital expenditures - Three months ended March 31	**$ 617**	$ 757	**$ 48**	$ 37	**$ 36**	$ 1	**$ 40**	$ 64	**$ 5**	$ 6	**$ 746**	$ 865
Total assets - As at March 31	**$ 14,168**	$ 13,075	**$ 1,177**	$ 981	**$ 1,057**	$ 802	**$ 1,180**	$ 883	**$ 199**	$ 114	**$ 17,781**	$ 15,855

[1] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventories.*

Note 2 Significant Accounting Policies

The interim consolidated financial statements of Husky Energy Inc. (“Husky” or “the Company”) have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2006, except as noted below. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Company’s annual report for the year ended December 31, 2006. Certain prior years' amounts have been reclassified to conform with current presentation.

Note 3 Changes in Accounting Policies

a) Financial Instruments and Hedging Activities

Effective January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants (“CICA”) section 3855, “Financial Instruments - Recognition and Measurement,” section 3865, “Hedges,” section 1530, “Comprehensive Income” and section 3861, “Financial Instruments - Disclosure and Presentation.” The Company has adopted these standards prospectively and the comparative interim consolidated financial statements have not been restated. Transition amounts have been recorded in retained earnings or accumulated other comprehensive income.

i) Financial Instruments

All financial instruments must initially be recognized at fair value on the balance sheet. The Company has classified each financial instrument into the following categories: held for trading financial assets and financial liabilities, loans or receivables, held to maturity investments, available for sale financial assets, and other financial liabilities. Subsequent measurement of the financial instruments is based on their classification. Unrealized gains and losses on held for trading financial instruments are recognized in earnings. Gains and losses on available for sale financial assets are recognized in other comprehensive income and are transferred to earnings when the asset is derecognized. The other categories of financial instruments are recognized at amortized cost using the effective interest rate method.

Upon adoption and with any new financial instrument, an irrevocable election is available that allows entities to classify any financial asset or financial liability as held for trading, even if the financial instrument does not meet the criteria to designate it as held for trading. The Company has not elected to classify any financial assets or financial liabilities as held for trading unless they meet the held for trading criteria. A held for trading financial instrument is not a loan or receivable and includes one of the following criteria:

- is a derivative, except for those derivatives that have been designated as effective hedging instruments;
- has been acquired or incurred principally for the purpose of selling or repurchasing in the near future; or
- is part of a portfolio of financial instruments that are managed together and for which there is evidence of a recent actual pattern of short-term profit taking.

For financial assets and financial liabilities that are not classified as held for trading, the transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability are added to the fair value initially recognized for that financial instrument. These costs are expensed to earnings using the effective interest rate method.

ii) Derivative Instruments and Hedging Activities

Derivative instruments are utilized by the Company to manage market risk against the volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company’s policy is not to utilize derivative instruments for speculative purposes. The Company may choose to designate derivative instruments as hedges. Hedge accounting continues to be optional.

At the inception of a hedge, the Company formally documents the designation of the hedge, the risk management objectives, the hedging relationships between the hedged items and hedging items and the method for testing the effectiveness of the hedge, which must be reasonably assured over the term of the hedge. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Company formally assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

All derivative instruments are recorded on the balance sheet at fair value in either accounts receivable, other assets, accounts payable and accrued liabilities, or other long-term liabilities. Freestanding derivative instruments are classified as held for trading financial instruments. Gains and losses on these instruments are recorded in other expenses in the consolidated statement of earnings in the period they occur. Derivative instruments that have been designated and qualify for hedge accounting have been classified as either fair value or cash flow hedges. For fair value hedges, the gains or losses arising from adjusting the derivative to its fair value are recognized immediately in earnings along with the gain or loss on the hedged item. For cash flow hedges, the effective portion of the gains and losses is recorded in other comprehensive income until the hedged transaction is recognized in earnings. When the earnings impact of the underlying hedged transaction is recognized in the consolidated statement of earnings, the fair value of the associated cash flow hedge is reclassified from other comprehensive income into earnings. Any hedge ineffectiveness is immediately recognized in earnings. For any hedging relationship that has been determined to be ineffective, hedge accounting is discontinued on a prospective basis.

The Company may enter into commodity price contracts to hedge anticipated sales of crude oil and natural gas production to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream oil and gas revenues as the related sales occur.

The Company may enter into commodity price contracts to offset fixed price contracts entered into with customers and suppliers to retain market prices while meeting customer or supplier pricing requirements. Gains and losses from these contracts are recognized in midstream revenues or costs of sales.

The Company may enter into power price contracts to hedge anticipated purchases of electricity to manage its exposure to price fluctuations. Gains and losses from these contracts are recognized in upstream operating expenses as the related purchases occur.

The Company may enter into interest rate swap agreements to hedge its fixed and floating interest rate mix on long-term debt. Gains and losses from these contracts are recognized as an adjustment to the interest expense on the hedged debt instrument.

The Company may enter into foreign exchange contracts to hedge its foreign currency exposures on U.S. dollar denominated long-term debt. Gains and losses on these instruments related to foreign exchange are recorded in the foreign exchange expense in the period to which they relate, offsetting the respective foreign exchange gains and losses recognized on the underlying foreign currency long-term debt. The remaining portion of the gain or loss is recorded in accumulated other comprehensive income and is adjusted for changes in the fair value of the instrument over the life of the debt.

The Company may enter into foreign exchange forwards and foreign exchange collars to hedge anticipated U.S. dollar denominated crude oil and natural gas sales. Gains and losses on these instruments are recognized as an adjustment to upstream oil and gas revenues when the sale is recorded.

For cash flow hedges that have been terminated or cease to be effective, prospective gains or losses on the derivative are recognized in earnings. Any gain or loss that has been included in accumulated other comprehensive income at the time the hedge is discontinued continues to be deferred in accumulated other comprehensive income until the original hedged transaction is recognized in earnings. However, if the likelihood of the original hedged transaction occurring is no longer probable, the entire gain or loss in accumulated other comprehensive income related to this transaction is immediately reclassified to earnings.

Fair values of the derivatives are based on quoted market prices where available. The fair values of swaps and forwards are based on forward market prices. If a forward price is not available for a commodity based forward, a forward price is estimated using an existing forward price adjusted for quality or location.

iii) Embedded Derivatives

Embedded derivatives are derivatives embedded in a host contract. They are recorded separately from the host contract when their economic characteristics and risks are not clearly and closely related to those of the host contract, the terms of the embedded derivatives are the same as those of a freestanding derivative and the combined contract is not classified as held for trading or designated at fair value. The Company has selected January 1, 2003 as its transition date for accounting for any potential embedded derivatives.

iv) Comprehensive Income

Comprehensive income consists of net earnings and other comprehensive income (“OCI”). OCI comprises the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge and the change in fair value of any available for sale financial instruments. Amounts included in OCI are shown net of tax. Accumulated other comprehensive income is a new equity category comprised of the cumulative amounts of OCI.

b) Accounting Changes

Effective January 1, 2007, the Company adopted the revised recommendations of CICA section 1506, “Accounting Changes.”

The new recommendations permit voluntary changes in accounting policy only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in earnings. The guidance was effective for all changes in accounting polices, changes in accounting estimates and corrections of prior period errors initiated in periods beginning on or after January 1, 2007.

Note 4 Cash Flows - Change in Non-cash Working Capital

	Three months ended March 31	
	2007	2006
a) Change in non-cash working capital was as follows:		
Decrease (increase) in non-cash working capital		
Accounts receivable	**$ 2**	$ 104
Inventories	**8**	32
Prepaid expenses	**(1)**	4
Accounts payable and accrued liabilities	**(585)**	(418)
Change in non-cash working capital	**$ (576)**	$ (278)
Relating to:		
Operating activities	**$ (638)**	$ 172
Financing activities	**218**	(419)
Investing activities	**(156)**	(31)
b) Other cash flow information:		
Cash taxes paid	**$ 768**	$ 129
Cash interest paid	**23**	32

Note 5 Bank Operating Loans

At March 31, 2007, the Company had unsecured short-term borrowing lines of credit with banks totalling $220 million (December 31, 2006 - $220 million). As at March 31, 2007, bank operating loans (excluding reclassified outstanding cheques) were $5 million (December 31, 2006 - nil) and letters of credit under these lines of credit totalled $30 million (December 31, 2006 - $19 million).

Note 6 Long-term Debt

	Maturity	March 31 2007	Dec. 31 2006	March 31 2007	Dec. 31 2006
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Medium-term notes [(1)]	2009	**$ 204**	$ 300	**$ -**	$ -
6.25% notes	2012	**461**	466	**400**	400
7.55% debentures	2016	**231**	233	**200**	200
6.15% notes	2019	**346**	350	**300**	300
8.90% capital securities	2028	**259**	262	**225**	225
Debt issue costs [(2)]		**(14)**	-	**-**	-
Unwound interest rate swaps [(3)]		**40**	-	**-**	-
Total long-term debt		**1,527**	1,611	**$1,125**	$ 1,125
Amount due within one year		**-**	(100)		
		$ 1,527	$ 1,511		

[(1)] *The carrying value of the medium-term notes has been adjusted to fair value to meet the accounting requirements for a fair value hedge. Refer to note 11, Financial Instruments and Risk Management.*
[(2)] *Debt issue costs have been reclassified to long-term debt with the adoption of financial instruments. Previously, these deferred costs were included in other assets.*
[(3)] *The unamortized portion of the gain on previously unwound interest rate swaps that would be designated as fair value hedges is required to be included in the carrying value of long-term debt with the adoption of financial instruments.*

Interest - net consisted of:

	Three months ended March 31 2007	2006
Long-term debt	**$ 28**	$ 37
Short-term debt	**1**	1
	29	38
Amount capitalized	**(3)**	(11)
	26	27
Interest income	**(5)**	-
	$ 21	$ 27

Foreign exchange consisted of:

	Three months ended March 31 2007	2006
Gain on translation of U.S. dollar denominated long-term debt	**$ (14)**	$ (1)
Cross currency swaps	**4**	(1)
Other (gains) losses	**9**	(3)
	$ (1)	$ (5)

Note 7 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Three months ended March 31	
	2007	2006
Asset retirement obligations at beginning of period	**$ 622**	$ 557
Liabilities incurred	**8**	6
Liabilities settled	**(14)**	(8)
Accretion	**12**	9
Asset retirement obligations at end of period	**$ 628**	$ 564

At March 31, 2007, the estimated total undiscounted inflation adjusted amount required to settle outstanding asset retirement obligations was $3.8 billion. These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 30 years into the future. This amount has been discounted using credit adjusted risk free rates ranging from 6.2% to 6.5%.

Note 8 Commitments and Contingencies

The Company has no material litigation other than various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial position, results of operations or liquidity.

Note 9 Share Capital

The Company's authorized share capital consists of an unlimited number of no par value common and preferred shares.

Common Shares

Changes to issued common shares were as follows:

	Three months ended March 31			
	2007		2006	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of period	424,268,509	$ 3,533	424,125,078	$ 3,523
Options exercised	37,798	3	45,500	3
Balance at March 31	**424,306,307**	**$ 3,536**	424,170,578	$ 3,526

Stock Options

A summary of the status of the Company's stock option plan is presented below:

	Three months ended March 31			
	2007		2006	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	5,828	$ 32.81	7,285	$ 25.81
Granted	-	$ -	340	$ 66.34
Exercised for common shares	(37)	$ 23.99	(46)	$ 20.21
Surrendered for cash	(384)	$ 24.11	(412)	$ 22.19
Forfeited	(122)	$ 69.11	(73)	$ 29.52
Outstanding at March 31	**5,285**	**$ 32.29**	7,094	$ 27.96
Options exercisable at March 31	**1,938**	**$ 27.01**	1,152	$ 22.94

	March 31, 2007				
	Outstanding Options			Options Exercisable	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices
$13.61 - $14.99	66	$ 14.45	1	66	$ 14.45
$15.00 - $22.99	67	$ 20.63	2	67	$ 20.63
$23.00 - $23.99	3,786	$ 23.48	2	1,522	$ 23.48
$24.00 - $39.99	279	$ 31.82	3	97	$ 31.38
$40.00 - $55.99	362	$ 51.90	3	88	$ 52.52
$56.00 - $76.39	725	$ 71.42	4	98	$ 67.28
	5,285	**$ 32.29**	**3**	**1,938**	**$ 27.01**

A downward adjustment of $0.35 was made to the exercise price of all outstanding stock options effective February 28, 2007, pursuant to the terms of the stock option plan under which the options were issued as a result of the special $0.50 per share dividend that was declared in February 2007.

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended March 31	
	2007	2006
Employer current service cost	**$ 6**	$ 4
Interest cost	**2**	2
Expected return on plan assets	**(2)**	(1)
Amortization of net actuarial losses	**1**	-
	$ 7	$ 5

Note 11 Financial Instruments and Risk Management

As described in note 3a), on January 1, 2007, the Company adopted the new CICA requirements relating to financial instruments. The following table summarizes the prospective adoption adjustments that were required as at January 1, 2007.

	December 31, 2006 (As Reported)	Adoption Adjustment	January 1, 2007 (As Restated)
Consolidated Balance Sheets			
Assets			
Accounts receivable	$ 1,284	$ 6	$ 1,290
Prepaid expenses	25	(2)	23
Other assets	44	(7)	37
Liabilities and Shareholders' Equity			
Accounts payable and accrued liabilities	2,574	(5)	2,569
Long-term debt due within one year	100	(2)	98
Long-term debt	1,511	34	1,545
Other long-term liabilities	756	(10)	746
Future income taxes	3,372	(6)	3,366
Retained earnings	6,087	4	6,091
Accumulated other comprehensive income	-	(18)	(18)

Commodity Price Risk Management

Power Consumption

At March 31, 2007, the Company had a cash flow hedge for power consumption as follows:

	Notional Volumes *(MW)*	Term	Price	Fair Value
Fixed price purchase	20.0	Apr. to Jun. 2007	$63.63/MWh	$ (0.4)

The fair value of the derivative has been recorded in accounts payable and accrued liabilities with the offset included in accumulated other comprehensive income.

Natural Gas Contracts

At March 31, 2007, the Company had the following external offsetting physical purchase and sale natural gas contracts, which met the definition of a derivative instrument:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	45,842	$ 3
Physical sale contracts	(45,842)	$ (1)

These contracts have been recorded at their fair value in accounts receivable and the resulting unrealized gain has been recorded in other expenses in the consolidated statement of earnings for the period.

Interest Rate Risk Management

At March 31, 2007, the Company had entered into a fair value hedge using interest rate swap arrangements whereby the fixed interest rate coupon on the medium-term notes was swapped to floating rates with the following terms:

Debt	Amount	Swap Maturity	Swap Rate *(percent)*	Fair Value
6.95% medium-term notes	$ 200	July 14, 2009	CDOR + 175 bps	$ 4

This contract has been recorded at fair value in other assets. During the first quarter of 2007, the Company realized a gain of $1 million (2006 - gain of $1 million) from interest rate risk management activities.

Foreign Currency Risk Management

At March 31, 2007, the Company had a cash flow hedge using the following cross currency debt swaps:

Debt	Swap Amount	Canadian Equivalent	Swap Maturity	Interest Rate *(percent)*	Fair Value
6.25% notes	U.S. $ 150	$ 212	June 15, 2012	7.41	$ (60)
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65	$ (4)
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67	$ (2)
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61	$ (1)

These contracts have been recorded at fair value in other long-term liabilities. The portion of the fair value of the derivative related to foreign exchange losses has been recorded in earnings to offset the foreign exchange on the translation of the underlying debt. The remainder of the loss has been included in accumulated other comprehensive income.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. During the first quarter of 2007, the impact of these contracts was a gain of less than $1 million (2006 - gain of $1 million).

Sale of Accounts Receivable

The Company has a securitization program to sell, on a revolving basis, accounts receivable to a third party up to $350 million. As at March 31, 2007 and December 31, 2006, no accounts receivable had been sold under the program.

Note 12 Subsequent Event

The Company entered into an agreement to dispose of certain non-core properties in Western Canada for total proceeds of $339 million. The transaction closed on April 11, 2007.

Husky Energy Inc. will host a conference call for analysts and investors on Wednesday, April 18, 2007 at 4:15 p.m. Eastern time to discuss Husky's first quarter results. To participate please dial 1-800-319-4610 beginning at 4:05 p.m. Eastern time.

Mr. John C.S. Lau, President & Chief Executive Officer, and other officers will be participating in the call.

A live audio webcast of the conference call will be available via Husky's website, www.huskyenergy.ca, under Investor Relations. The webcast will be archived for approximately 90 days.

Those unable to listen to the call live may listen to a recording by dialing 1-800-319-6413 one hour after the completion of the call, approximately 6:15 p.m. (EST), then dialing reservation number 3169. The Postview will be available until Friday, May 18, 2007.

Media are invited to listen to the conference call by dialing 1-800-597-1419 beginning at 4:05 p.m. Eastern time.

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