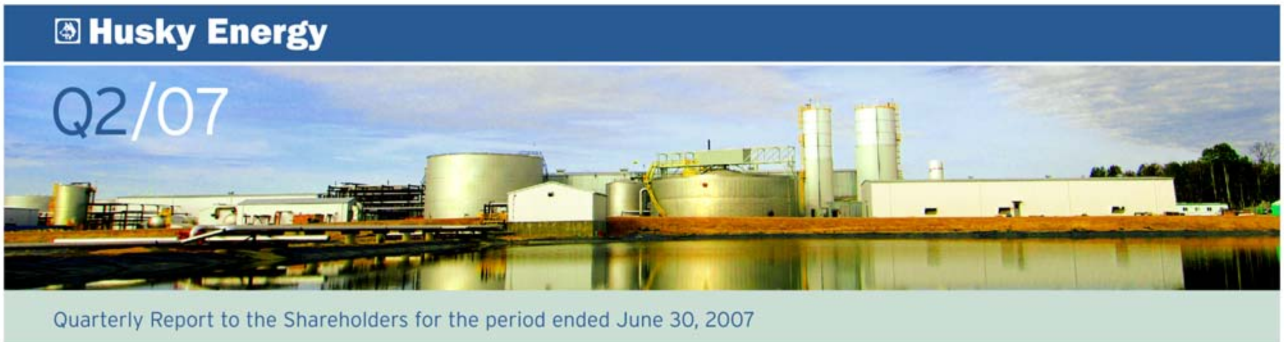
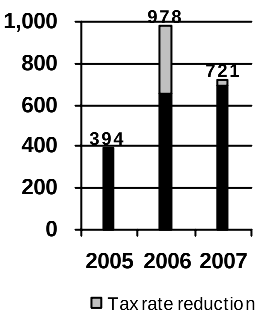
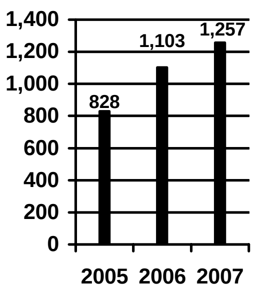


HUSKY ENERGY REPORTS 2007 SECOND QUARTER RESULTS

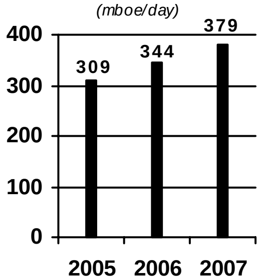
Second Quarter Net Earnings
($ millions)



Second Quarter Cash Flow from Operations
($ millions)



Second Quarter Total Production
(mboe/day)



Calgary, Alberta – Husky Energy Inc. reported net earnings of $721 million or $0.85 per share (diluted) in the second quarter of 2007 compared with $978 million or $1.15 per share (diluted) in the same quarter of 2006. Net earnings for the second quarter of 2007 included a non-recurring benefit due to tax rate reductions of $30 million or $0.04 per share (diluted) compared with $328 million or $0.39 per share (diluted) in the second quarter of 2006. Excluding the non-recurring tax benefits, the second quarter net earnings were $691 million for 2007 compared with $650 million for 2006.

Cash flow from operations in the second quarter was $1.3 billion or $1.48 per share (diluted), a 14% increase compared with $1.1 billion or $1.30 per share (diluted) in the same quarter of 2006. Sales and operating revenues, net of royalties, were $3.2 billion in the second quarter of 2007, up 4% compared with $3.0 billion in the second quarter of 2006.

In the second quarter of 2007, total production averaged 379,100 barrels of oil equivalent per day, a 10% increase over 344,000 barrels of oil equivalent per day in the second quarter of 2006. Total crude oil and natural gas liquids production was 276,500 barrels per day and natural gas production was 615.7 million cubic feet per day.

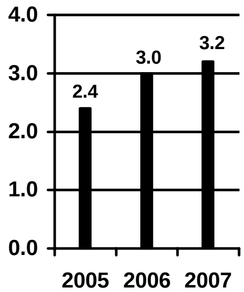
"Husky achieved strong financial performance for the quarter despite the continuing weakness in the U.S. dollar," said Mr. John C.S. Lau, President & Chief Executive Officer, Husky Energy Inc. "In July, the acquisition of the Lima refinery in Ohio, which represents a significant step in Husky's strategy of integrated heavy oil and bitumen development, will contribute positively to Husky's earnings and cash flow."

Subsequent to the end of the second quarter, Husky completed the acquisition of the refinery in Lima, Ohio from Valero Energy Corporation. The purchase price was U.S. $1.9 billion, plus net working capital. Various options will be examined to enhance the value of this refinery including opportunities to integrate Husky's heavy oil and oil sands production.

The Tucker Oil Sands project, which is expected to reach 30,000 barrels per day by the end of 2008, completed its initial warm-up phase and is ramping up SAGD production.

Second Quarter
Sales and Operating
Revenues

($ billions)



The Sunrise Oil Sands project continues to progress on schedule with the completion of the front-end engineering design work planned for the fourth quarter of 2007.

Production at the White Rose oil field in the second quarter reached approximately 136,000 barrels per day and averaged 90,300 barrels per day net to Husky. A seventh production well has been completed, bringing total reservoir capacity to 140,000 barrels per day. The field is currently undergoing a 16-day planned turnaround. Drilling of the C-30 delineation well in the western section of the White Rose field commenced in June and is continuing.

At the Lloydminster Upgrader, a scheduled 40-day turnaround has been completed. The majority of the debottleneck projects were completed during the turnaround. Throughput capacity of 82,000 barrels per day will be realized in the fourth quarter of 2007 pending completion of remaining work items. Front-end engineering design for a potential expansion of the Upgrader continues and is expected to be completed in the fourth quarter of 2007.

With regards to exploration, Husky was awarded an 87.5% interest in two exploration licences offshore Greenland. The two blocks cover an area of 21,067 square kilometres and are located approximately 120 kilometres offshore the west coast of Disko Island.

Second Quarter Financial Highlights 2007 versus 2006

- Earnings per share to $0.85 from $1.15
- Return on equity to 27.1% from 34.8%
- Return on average capital employed to 23.8% from 28.2%
- Cash flow per share to $1.48 from $1.30
- Debt to capital employed ratio to 12% from 16%
- Debt to cash flow ratio to 0.3 from 0.4
- Market capitalization increased to $37 billion from $30 billion

Internationally, Husky has commenced a seismic program in the South China Sea over Block 29/26 that contains the Liwan natural gas discovery and the adjacent Block 29/06. The program will evaluate exploration leads for future drilling locations. Delineation of the Liwan discovery will commence in the second half of 2008 upon the arrival of the West Hercules deep water drilling rig.

In Minnedosa, construction of the new ethanol production facility is currently 68% complete with commissioning expected in the fourth quarter of 2007.

Husky's financial position remains strong. At June 30, 2007, Husky's debt to cash flow ratio was 0.3 to 1 and debt to capital was 12%.

For the first six months of 2007, Husky's net earnings were $1.4 billion or $1.61 per share (diluted), compared with $1.5 billion or $1.77 per share (diluted) for the same period in 2006. Cash flow from operations for the first six months of 2007 was $2.6 billion or $3.04 per share (diluted), compared with $2.1 billion or $2.44 per share (diluted) for the same period in 2006.

Production in the first six months of 2007 was 384,600 barrels of oil equivalent per day, compared with 348,700 barrels of oil equivalent per day in the same period in 2006. Total crude oil and natural gas liquids production was 279,900 barrels per day, compared with 235,500 barrels per day during the first six months of 2006. Natural gas production was 627.8 million cubic feet per day, compared with 679.0 million cubic feet per day in the first six months of 2006.

Our current forecast for crude oil production in 2007 remains within our guidance range. Our current forecast for natural gas production in 2007 will likely be less than 670 million cubic feet per day as a result of the redeployment of capital, delayed natural gas well tie-ins and capital project delays.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A") JULY 18, 2007

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2.0	Core Business Strategy	8.0	Changes in Accounting Policies
3.0	Capability to Deliver Results	9.0	Outstanding Share Data
4.0	Results of Operations	10.0	Non-GAAP Measures
5.0	Liquidity and Capital Resources	11.0	Reader Advisories
6.0	Risks and Risk Management	12.0	Forward-looking Statements

1.0 QUARTERLY FINANCIAL RESULTS

Husky's net earnings for the second quarter of 2007 were $721 million, down $257 million or 26% compared with the second quarter of 2006.

Second Quarter

The decrease in net earnings in the second quarter of 2007 was mainly related to a variance of $290 million in income taxes, primarily from a future tax recovery recorded in the second quarter of 2006. In addition, stock-based compensation was $28 million higher in the second quarter of 2007 compared with the second quarter of 2006.

Earnings before income taxes were $992 million in the second quarter of 2007 compared with $959 million in the second quarter of 2006, an increase of $33 million. The increase in earnings before income taxes includes higher earnings from the Upstream and Refined Products segments partially offset by lower earnings from the Midstream segment. During the second quarter of 2007, the upgrader at Lloydminster underwent a 49 day turnaround and as a result synthetic crude sales volume was 42% lower than the corresponding quarter in 2006.

Cash flow from operations was $1.3 billion in the second quarter of 2007 compared with $1.1 billion in the second quarter of 2006.

Six Months

Husky's net earnings for the first six months of 2007 were $1.4 billion compared with $1.5 billion during the first six months of 2006. The decrease in net earnings in the first six months of 2007 resulted primarily from the tax recovery recorded in 2006.

Earnings before income taxes were $1.9 billion in the first six months of 2007 compared with $1.7 billion in the first six months of 2006. The increase in earnings before income taxes in 2007 resulted from the same factors that affected the second quarter.

Cash flow from operations was $2.6 billion in the first six months of 2007 compared with $2.1 billion in the first six months of 2006.

Financial Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except per share amounts and ratios)	**2007**	2006	**2007**	2006
Segmented earnings				
Upstream	**$ 636**	$ 822	**$ 1,216**	$ 1,234
Midstream	**77**	140	**188**	290
Refined Products	**53**	52	**73**	68
Corporate and eliminations	**(45)**	(36)	**(106)**	(90)
Net earnings	**$ 721**	$ 978	**$ 1,371**	$ 1,502
Per share - Basic and diluted [(1)]	**$ 0.85**	$ 1.15	**$ 1.61**	$ 1.77
Cash flow from operations	**1,257**	1,103	**2,581**	2,070
Per share - Basic and diluted [(1)]	**1.48**	1.30	**3.04**	2.44
Ordinary quarterly dividend per common share [(1)]	**0.25**	0.125	**0.50**	0.25
Special dividend per common share [(1)]	**-**	-	**0.25**	-
Total assets	**17,969**	16,328	**17,969**	16,328
Total long-term debt including current portion	**1,423**	1,722	**1,423**	1,722
Return on equity [(2)] *(percent)*	**27.1**	34.8	**27.1**	34.8
Return on average capital employed [(2)] *(percent)*	**23.8**	28.2	**23.8**	28.2

[(1)] *Reflects a two-for-one share split on June 27, 2007, which has been applied retroactively. Refer to Note 9 to the Consolidated Financial Statements.*
[(2)] *Calculated for the 12 months ended for the dates shown.*

2.0 CORE BUSINESS STRATEGY

Our core business strategy was presented in our 2006 annual Management's Discussion and Analysis, which is available from the Canadian Securities Administrators' web site, www.sedar.com, the U.S. Securities and 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 growth projects. 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 in Indonesia. Our plans for the Midstream and Refined Products segments involve enhancing performance and capturing new value throughout the value chain by further integrating existing operations and the Lima refinery, optimizing our plant operations and expanding plant and infrastructure operations where warranted.

3.0 CAPABILITY TO DELIVER RESULTS

Our current capacity to deliver results was also provided in our recently filed MD&A and 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 and opportunities that will provide a satisfactory return on investment. The major projects that are currently at varying stages of development 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 conditions that relate to safety, conservation and production control.

In early June 2007, the seventh production well was completed. The completion of this well has increased reservoir production capacity to the approved 140 mbbls/day. 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 (87 mbbls/day to 91 mbbls/day Husky's share) on an annual average basis. One additional gas injection well remains to be drilled in the third quarter of 2007. The completion of this well will conclude our 18 well development plan for the South Avalon portion of the White Rose oil field.

SeaRose FPSO Tie-back Program

In June 2007, glory hole excavation into the seabed commenced at what will become the North Amethyst drill centre using the suction hopper dredge vessel, Vasco da Gama. The North Amethyst glory hole is currently 65% complete. Front-end engineering design studies to support the tie-back of various satellite reservoirs and required facility modifications are, in total, approximately 80% complete.

The South White Rose Extension development plan amendment is currently under review by the C-NLOPB. We also plan to submit applications for our proposed tie-backs at North Amethyst and West White Rose in the coming months.

East Coast Canada Exploration and White Rose Delineation

We are currently drilling the C-30 delineation well, which will provide additional data on resources discovered in 2006 in the western section of the White Rose field. A side-track of the C-30 well is planned to further evaluate reservoir quality and we intend to conduct a drill stem test to determine productivity in this part of the reservoir.

In addition, evaluation of 3-D seismic data acquired over Exploration Licences 1067 and 1011 is progressing.

Tucker Oil Sands Project

During the second quarter, we continued to steam the reservoir at Tucker through the well pairs, both the production and injection wells. At the end of the second quarter, all of the well pairs had been switched to steam-assisted gravity drainage ("SAGD") production, steaming through the injector of each pair. Initially, production has a high steam/oil ratio, which is expected to improve in the coming months as production ramps up.

Sunrise Oil Sands Project

The front-end engineering design of the Sunrise Oil Sands project is continuing and is approximately 67% 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 of bitumen sales, and will ultimately be developed by successive phases to a production plateau of 200 mbbls/day.

In the field, early site preparation work will be completed this fall, expansion of the drilling camp and commencement of accommodations for construction workers for the second half of 2008. The winter 2008 drilling program is in the planning phase; currently, 50 stratigraphic test and observation well locations are being surveyed and licensed. Regulatory application for the project water supply was submitted in early spring and work on water disposal logistics continues. We are also continuing to discuss and plan the general area's infrastructure needs with various industry participants.

Caribou

At Caribou, we completed geological mapping and integration with the 3-D seismic acquired earlier in 2007. Geological modeling and simulation studies continued in the second quarter. Discussions and negotiations are continuing with regulatory authorities and various stakeholder groups on the Energy and Utilities Board and Alberta Environment application. Front-end engineering has commenced and is expected to be completed in the fourth quarter of 2007.

SALESKI

At Saleski, geological mapping and cross sections are being assembled for stratigraphic drilling locations. An initial survey is underway to determine the appropriate route for an all season access road. In addition, we are examining the technical merits of various production processes for Saleski.

NORTHWEST TERRITORIES EXPLORATION

In May 2007, we were awarded EL 443, which covers 224,886 acres adjacent to our existing landholdings in the Central Mackenzie Valley. In respect of our 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 second quarter of 2007, we began to acquire seismic data in the South China Sea over Block 29/26, which contains the Liwan natural gas discovery, and the adjacent Block 29/06. The program will cover a total of 766,000 acres and will evaluate exploration leads for future drilling locations. Proposed delineation well locations are currently being evaluated based on 3-D seismic data acquired earlier. Delineation of Liwan is planned to commence in the second half of 2008 upon the arrival of the West Hercules deep water drilling rig, which is currently being constructed. At June 30, 2007, the West Hercules was 64% complete. We have secured the West Hercules for three years.

On June 27, 2007, we entered into an agreement for the use of a jack-up rig for shallow water drilling. The rig will be available in October 2007 and will be deployed in the South China Sea on Block 23/15. We will continue to pursue securing an additional rig suitable for the remainder of our shallow water exploration program.

INDONESIA NATURAL GAS DEVELOPMENT AND EXPLORATION

In Indonesia, our negotiations continued with BPMIGAS and other players in order to expedite the approval process. Our amended development plan for the BD natural gas and condensate field in the Madura Strait was submitted to BPMIGAS for their approval. Environmental impact studies were started during the second quarter.

We are currently assessing bids to acquire 3-D seismic data on our recently awarded exploration block, East Bawean II.

OFFSHORE GREENLAND

In June 2007, we were awarded two adjacent exploration licences offshore Greenland. Block 5 (2007-22) is 2.5 million acres and Block 7 (2007-24) is 2.7 million acres. Both blocks are west of Disko Island off the west coast of Greenland in less than 500 metres of water. We have committed to spend U.S. $10.6 million on Block 5 and U.S. $28 million on Block 7 over the next three years. This work commitment includes the acquisition of 7,000 kilometres of 2-D seismic and 1,000 kilometres of 3-D seismic.

3.2 MIDSTREAM

LLOYDMINSTER TO HARDISTY PIPELINE EXPANSION

Construction of the second phase of our pipeline expansion is approximately 10% 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 91% completion. We anticipate a decision on whether to proceed with the expansion in the second half of 2007.

3.3 REFINED PRODUCTS

ACQUISITION OF THE LIMA OHIO REFINERY

In May 2007, we announced the pending acquisition of the Valero refinery at Lima, Ohio, located between Dayton and Toledo. The acquisition closed on July 3, 2007 for a purchase price of U.S. $1.9 billion, plus net working capital. An additional U.S. $540 million was paid for feedstock and product inventory.

The Lima refinery has a nameplate capacity of 165 mbbls/day and processes primarily sweet crude oil and limited amounts of sour heavy crude oil. The refinery produces conventional gasoline, reformulated gasoline for oxygenate blending, diesel, jet fuels and petrochemicals. We intend to review options in respect of reconfiguring and expanding this refinery to process heavy crude oil and bitumen as primary feedstocks.

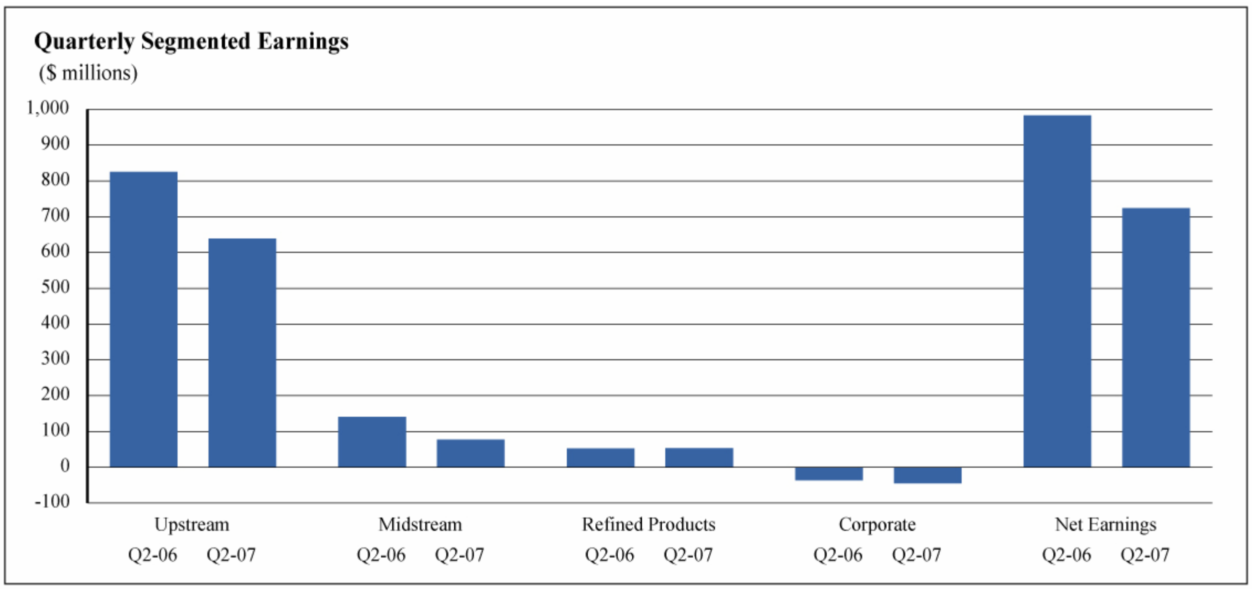
This acquisition was financed with a short-term bridge facility and existing credit facilities.

MINNEDOSA ETHANOL PLANT

At Minnedosa, the construction of the new ethanol plant is 68% complete. We expect to commission the plant and achieve 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 June 30		Six months ended June 30	
(millions of dollars)	**2007**	2006	**2007**	2006
Gross revenues	**$ 1,828**	$ 1,658	**$ 3,591**	$ 3,151
Royalties	**235**	207	**433**	413
Net revenues	**1,593**	1,451	**3,158**	2,738
Operating and administration expenses	**344**	308	**667**	619
Depletion, depreciation and amortization	**407**	354	**806**	705
Other	**(49)**	-	**(49)**	-
Income taxes	**255**	(33)	**518**	180
Earnings	**$ 636**	$ 822	**$ 1,216**	$ 1,234

THE UPSTREAM BUSINESS ENVIRONMENT

Commodity Prices

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

Average Sales Prices		Three months ended June 30		Six months ended June 30	
		2007	2006	**2007**	2006
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 72.28**	$ 73.74	**$ 68.28**	$ 70.35
Medium crude oil		**48.15**	58.42	**47.26**	48.29
Heavy crude oil		**38.41**	48.12	**38.03**	37.28
Total average		**56.99**	60.18	**54.68**	52.54
Natural Gas	*($/mcf)*				
Average		**6.91**	5.95	**6.92**	7.01

The prices received 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 limited to pipelines.

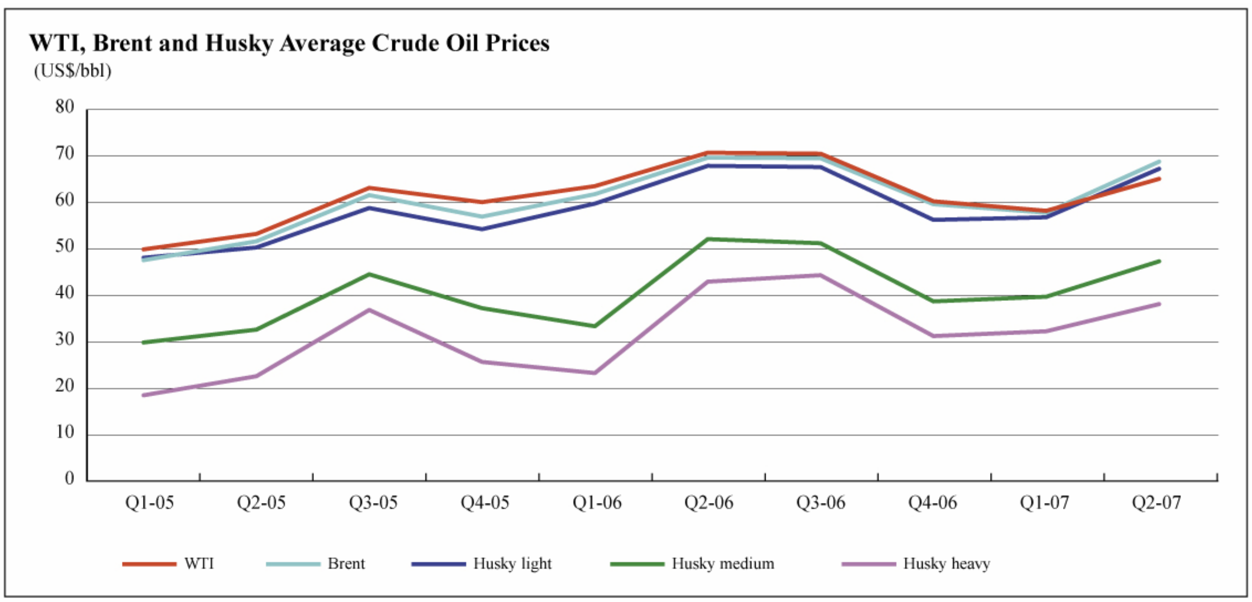
Our Upstream results are significantly influenced by commodity prices. The following table shows certain select average quarterly market benchmark prices:

Average Benchmark Prices and U.S. Exchange Rate		Three months ended				
		June 30 2007	March 31 2007	Dec. 31 2006	Sept. 30 2006	June 30 2006
WTI crude oil [1]	*(U.S. $/bbl)*	**65.03**	58.16	60.21	70.48	70.70
Brent crude oil [2]	*(U.S. $/bbl)*	**68.76**	57.75	59.68	69.49	69.62
Canadian light crude 0.3% sulphur	*($/bbl)*	**72.61**	67.76	65.12	79.65	78.97
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**39.02**	38.25	35.24	49.61	48.65
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**7.55**	6.77	6.56	6.58	6.79
NIT natural gas	*($/GJ)*	**6.99**	7.07	6.03	5.72	5.95
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**20.36**	17.32	21.75	19.24	17.99
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.911**	0.854	0.878	0.892	0.891

[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

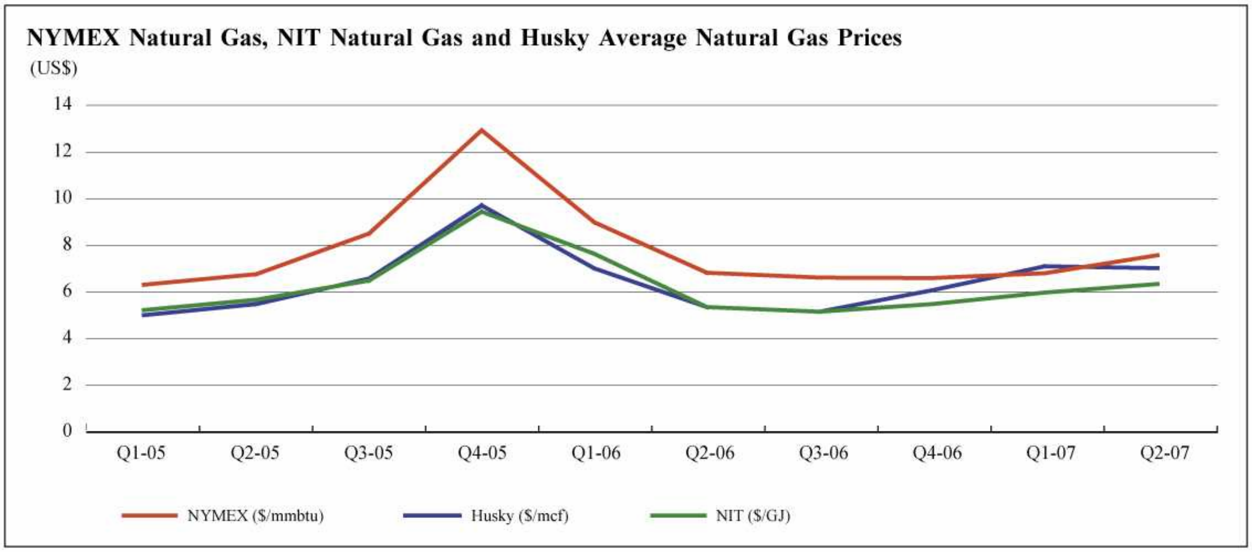
The following graph illustrates the relative changes over several quarters in the realized prices of our three main crude oil categories expressed in U.S. dollars and West Texas Intermediate ("WTI"), the main benchmark crude oil.



The majority of our crude oil production is marketed in North America and the primary benchmark crude oil in North America is WTI. During the second quarter of 2007, WTI trended up from the first quarter of 2007 but average WTI prices were lower than in the second quarter of 2006. During the second quarter of 2007, WTI prices came under pressure whereas other benchmark crude oil categories, such as Brent, traded at a premium to the North American standard crude. Stocks of WTI, which is normally a clear market indicator, were high as a result of higher Canadian crude oil exported to the United States and higher than usual maintenance and outages of refineries that would normally take WTI. Brent on the other hand, was the best market indicator as it increased in the second quarter of 2007 and averaged at a similar level to the second quarter of 2006. At the end of the second quarter of 2007, crude oil prices were spiking in reaction to production disruption in Nigeria.

Natural Gas

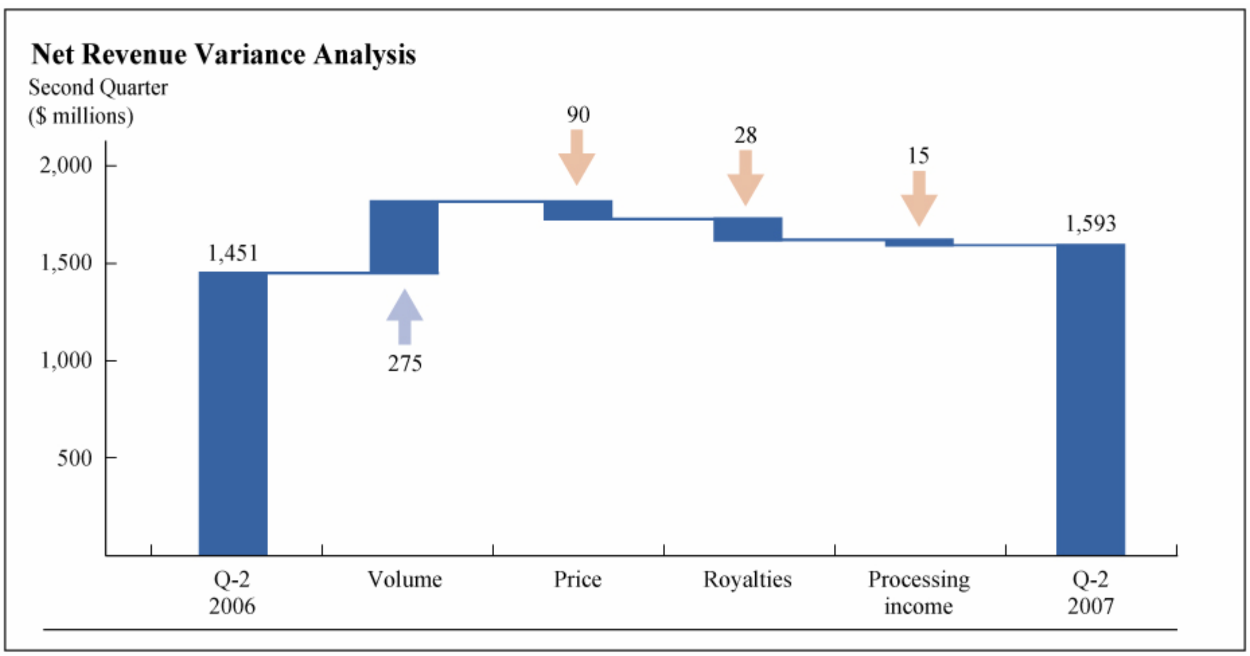
The following graph illustrates the relative changes over several quarters in our natural gas price realized compared with two major benchmark prices.



Since the beginning of 2006, moderate weather in the major North American market areas has resulted in lower heating and cooling demand and therefore higher natural gas supplies. These events have kept natural gas prices on the low side. The NYMEX price for near month settlement averaged U.S. $7.55/mmbtu during the second quarter of 2007.

Revenue

Second Quarter



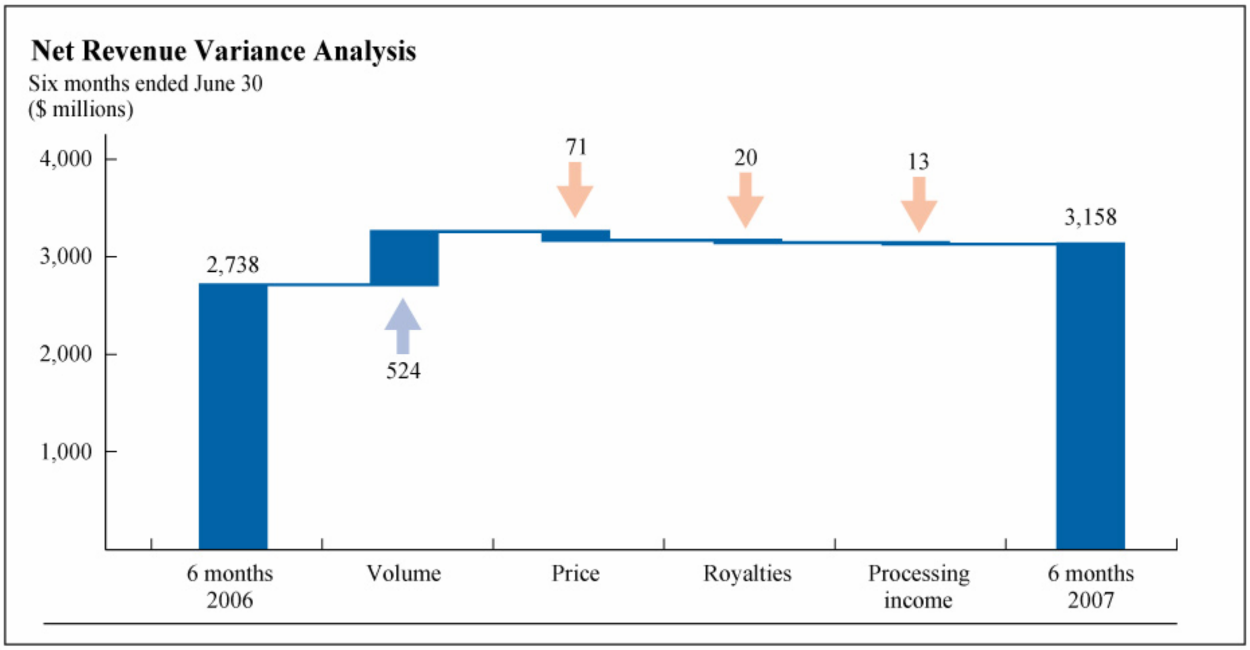
During the second quarter of 2007, our upstream net revenues were $1.6 billion, compared with $1.5 billion in the second quarter of 2006.

In the second quarter of 2007, Western Canada was the source of 57% of our crude oil and 100% of our natural gas production resulting in 56% of upstream revenue before royalties. East Coast Canada contributed 38% of our crude oil production, 79% of our light crude oil production and resulted in 39% of upstream revenue before royalties. China contributed 5% of revenue.

In the second quarter of 2006, Western Canada was the source of 71% of our crude oil and 100% of our natural gas production resulting in 71% of upstream revenue before royalties. East Coast Canada contributed 24% of our crude oil production, 64% of our light crude oil production and resulted in 24% of upstream revenue before royalties. China contributed 5% of revenue.

On April 11, 2007, we closed a transaction to dispose of several properties located mainly in northwest Alberta with production of approximately 5,200 boe/day.

Six Months



During the first six months of 2007, our upstream net revenues were $3.2 billion, compared with $2.7 billion in the corresponding period of 2006.

In the first six months of 2007, Western Canada was the source of 58% of our crude oil and 100% of our natural gas production resulting in 58% of upstream revenue before royalties. East Coast Canada contributed 37% of our crude oil production, 77% of our light crude oil production and resulted in 37% of upstream revenue before royalties. China contributed 5% of revenue.

In the first half of 2006, Western Canada was the source of 71% of our crude oil and 100% of our natural gas production resulting in 71% of upstream revenue before royalties. East Coast Canada contributed 24% of our crude oil production, 63% of our light crude oil production and resulted in 24% of upstream revenue before royalties. China contributed 5% of revenue.

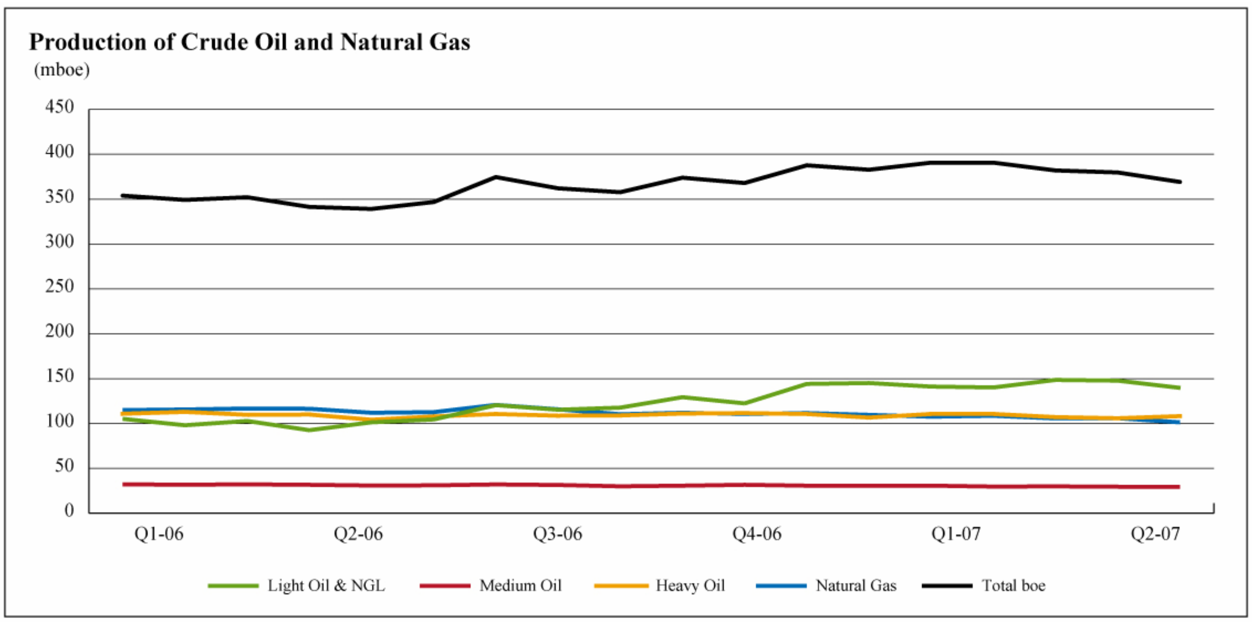
Effective Royalty Rates

Royalties per unit of production and percentage of upstream gross revenues	Three months ended June 30				Six months ended June 30			
	2007		2006		**2007**		2006	
	$	**%**	**$**	**%**	**$**	**%**	**$**	**%**
Crude oil & NGL								
Light crude oil & NGL	**7.72**/*bbl*	**11**	6.85/*bbl*	9	**6.08**/*bbl*	**9**	6.59/*bbl*	9
Medium crude oil	**8.34**/*bbl*	**17**	11.04/*bbl*	19	**8.17**/*bbl*	**17**	8.73/*bbl*	18
Heavy crude oil & bitumen	**5.00**/*bbl*	**13**	6.39/*bbl*	13	**4.86**/*bbl*	**13**	4.71/*bbl*	13
Natural gas	**1.17**/*mcf*	**17**	0.92/*mcf*	15	**1.21**/*mcf*	**17**	1.29/*mcf*	18
Total	**6.81**/*boe*	**13**	6.62/*boe*	13	**6.22**/*boe*	**12**	6.55/*boe*	13

Upstream Revenue Mix

Percentage of upstream net revenues	Three months ended June 30		Six months ended June 30	
	2007	2006	**2007**	2006
Crude oil & NGL				
Light crude oil & NGL	**53**	41	**52**	42
Medium crude oil	**6**	8	**6**	8
Heavy crude oil & bitumen	**20**	28	**20**	23
	79	77	**78**	73
Natural gas	**21**	23	**22**	27
	100	100	**100**	100

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				
		June 30 2007	March 31 2007	Dec. 31 2006	Sept. 30 2006	June 30 2006
Crude oil and NGL	*(mbbls/day)*					
Western Canada						
Light crude oil & NGL		**25.3**	30.1	30.4	30.2	29.8
Medium crude oil		**26.8**	27.5	28.0	28.1	28.5
Heavy crude oil & bitumen		**105.4**	108.0	109.5	107.9	105.6
		157.5	165.6	167.9	166.2	163.9
East Coast Canada						
White Rose - light crude oil		**90.3**	89.4	79.4	75.9	53.0
Terra Nova - light crude oil		**15.5**	14.7	6.7	-	2.8
China						
Wenchang - light crude oil & NGL		**13.2**	13.6	11.7	11.1	12.1
		276.5	283.3	265.7	253.2	231.8
Natural gas	*(mmcf/day)*	**615.7**	640.0	662.2	669.1	672.8
Total	*(mboe/day)*	**379.1**	390.0	376.1	364.7	344.0

2007 Gross Production Guidance

		Full Year Forecast 2007	Six months ended June 30 **2007**	Year ended Dec. 31 2006
Crude oil & NGL	*(mbbls/day)*			
Light crude oil & NGL		**128 - 135**	**146**	111
Medium crude oil		**28 - 30**	**27**	29
Heavy crude oil & bitumen		**122 - 130**	**107**	108
		278 - 295	**280**	248
Natural gas	*(mmcf/day)*	**670 - 690**	**628**	672
Total barrels of oil equivalent	*(mboe/day)*	**390 - 410**	**385**	360

Our current forecast for crude oil production in 2007 remains within our guidance range. Our current forecast for natural gas production in 2007 will likely be less than 670 mmcf/day as a result of the redeployment of capital, delayed natural gas well tie-ins and capital project delays.

Crude Oil Production

In the second quarter of 2007, Western Canada crude oil and NGL production declined 5% compared with the second quarter of 2006. The decline in production was mainly due to an early spring break-up combined with capital project delays and the disposition of properties in April 2007. Plans are being implemented to increase field work now that spring break-up is over.

Light crude oil production from the White Rose and Terra Nova oil fields off the East Coast of Canada averaged 106 mbbls/day during the second quarter of 2007 compared with 56 mbbls/day during the second quarter of 2006, an increase of 89%. 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. A seventh production well was recently completed and has increased the field capacity to 140 mbbls/day. Our interest in Terra Nova production averaged 15.5 mbbls/day in the second quarter of 2007 compared with 2.8 mbbls/day in the second quarter of 2006. Terra Nova production recovered from mechanical issues, which were resolved in late 2006. During June 2007, production at Terra Nova was reduced by a scheduled turnaround.

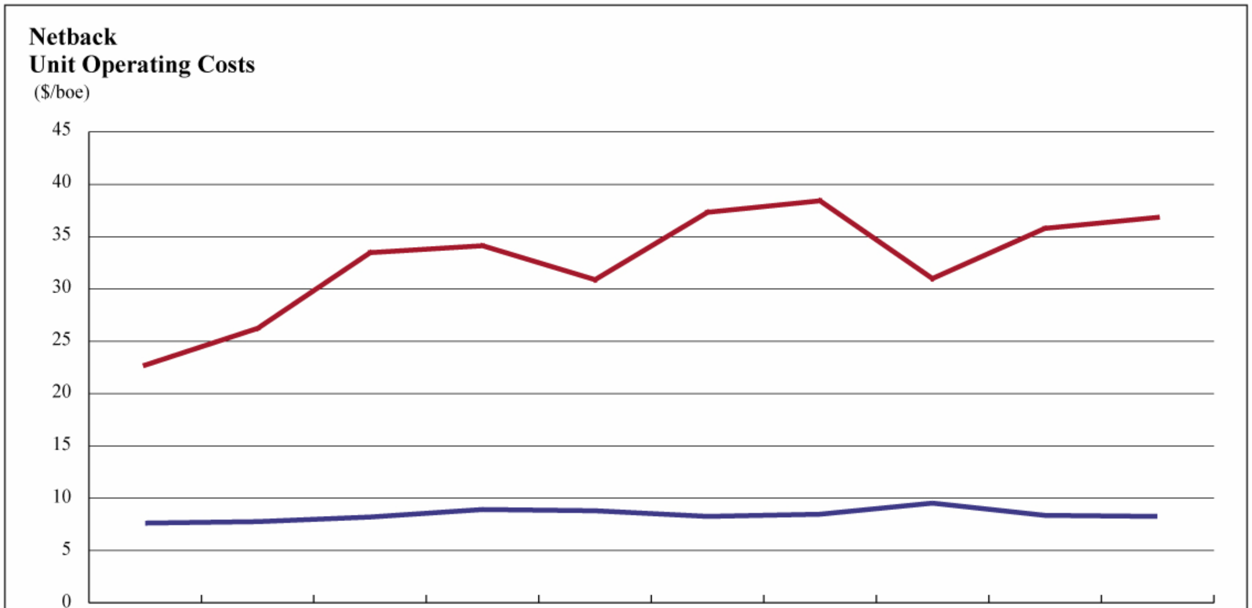
At Wenchang in the South China Sea, production was 9% higher in the second quarter of 2007 compared to the same period in 2006. New production wells and well workovers in the fourth quarter of 2006 boosted production levels. NGL production also augmented crude oil production with the installation of gas liquid extraction facilities, which became operational in October 2006.

Natural Gas Production

All of our natural gas is produced in Western Canada. In the second 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 east central and southern Alberta and southern Saskatchewan.

Production of natural gas was down approximately 8% in the second quarter of 2007 compared with the second quarter of 2006 primarily due to property divestitures, infrastructure maintenance, capital project delays as well as restrictions due to an early spring break-up.

OPERATING COSTS



	Q1-05	Q2-05	Q3-05	Q4-05	Q1-06	Q2-06	Q3-06	Q4-06	Q1-07	Q2-07
Netback	22.72	26.24	33.48	34.14	30.89	37.34	38.44	31.00	35.80	36.85
Operating Cost	7.60	7.74	8.18	8.90	8.78	8.24	8.45	9.51	8.34	8.24

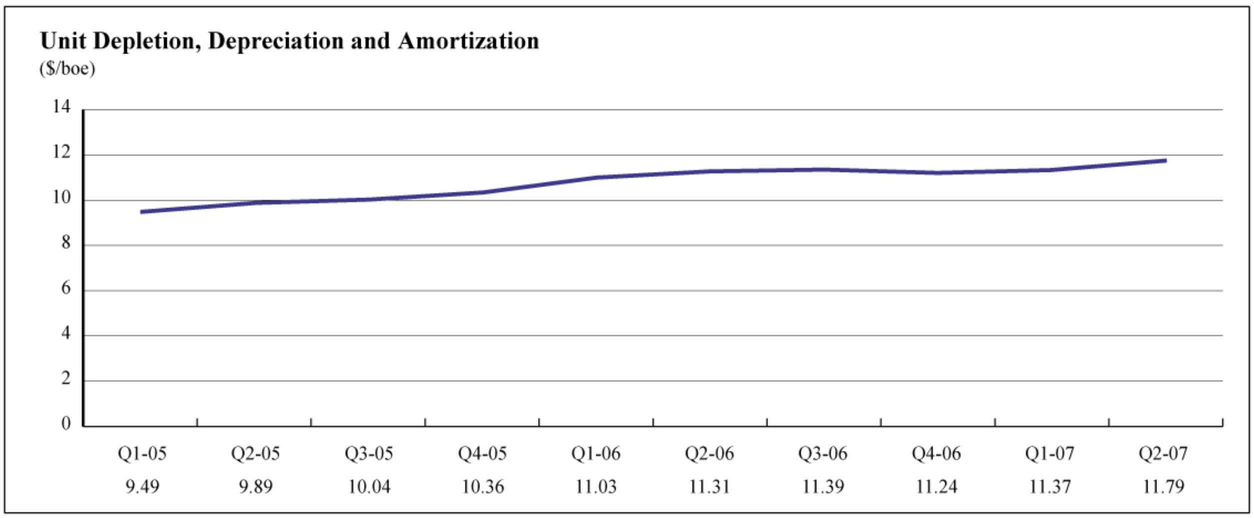
Operating costs in Western Canada averaged $11.10/boe in the second quarter of 2007 compared with $9.17/boe in the corresponding period in 2006, an increase of 21%. Unit operating costs in Western Canada, excluding the heavy oil operations in the Lloydminster area, averaged $9.82/boe in the second quarter of 2007 compared with $8.70/boe in the corresponding period in 2006, an increase of 13%.

The trend of increasing operating costs in Western Canada is related to the nature of exploitation necessary to manage production from maturing fields and new but more extensive and less prolific reservoirs. Western Canada operations require increasing amounts of infrastructure including more wells, more extensive pipeline systems, crude and water trucking, more extensive natural gas compression systems and complex tertiary recovery schemes. Cyclic steam and SAGD heavy oil and bitumen recovery schemes involve steaming cycles where the formation is heated while production ceases. These processes require higher energy consumption, workovers and generally more material costs. During the phase of thermal operations immediately after reservoir warm up, the steam/oil ratio is high and production of heavy oil or bitumen is low, resulting in higher than usual unit operating costs. In addition, higher levels of industry activity increase competition for resources and inflate costs. In managing rising operating costs, we attempt to keep our infrastructure, including gas plants, crude processing plants, transportation systems, compression systems, lease access and other infrastructure fully utilized and optimized.

Operating costs at the East Coast offshore operations averaged $4.00/bbl in the second quarter of 2007 compared with $4.97/bbl in the second quarter of 2006. Unit operating costs in the second 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 $3.04/bbl in the second quarter of 2007 compared with $2.41/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 in the third quarter of 2006.

DEPLETION, DEPRECIATION AND AMORTIZATION



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.

The Canadian cost centre DD&A averaged $11.79/boe in the second quarter of 2007 compared with $11.29/boe in the second quarter of 2006, an increase of 4%. The increase in DD&A results primarily from higher capital costs. Increasing capital is due to increased drilling and associated infrastructure in Western Canada and large capital investment developing offshore reserves off the East Coast of Canada.

DD&A in China averaged $11.89/boe in the second quarter of 2007 compared with $11.37/boe in the second quarter of 2006. Increasing unit DD&A results from declining reserve volume due to reservoir depletion.

OTHER

During the second quarter we recorded a $49 million gain on an embedded derivative related to a contract requiring payment in U.S. currency. The payments are expected to occur over the three-year period from mid 2008. This amount will fluctuate with the U.S./Cdn forward exchange rate until the actual contract settlement.

Operating Netbacks

	Western Canada		East Coast		International		Total	
Three months ended June 30	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Light Crude Oil *(per boe)* [1]								
Sales price	**$ 59.41**	$ 62.34	**$ 73.79**	$ 76.57	**$ 75.14**	$ 77.80	**$ 71.53**	$ 72.56
Royalties [2]	**6.32**	7.14	**6.04**	1.82	**14.43**	16.35	**6.87**	5.21
Operating costs	**13.89**	12.88	**4.00**	4.97	**3.04**	2.41	**5.53**	6.95
	39.20	42.32	**63.75**	69.78	**57.67**	59.04	**59.13**	60.40
Medium Crude Oil *(per boe)* [1]								
Sales price	**47.81**	57.34	**-**	-	**-**	-	**47.81**	57.34
Royalties	**8.38**	10.76	**-**	-	**-**	-	**8.38**	10.76
Operating costs	**12.48**	11.52	**-**	-	**-**	-	**12.48**	11.52
	26.95	35.06	**-**	-	**-**	-	**26.95**	35.06
Heavy Crude Oil & Bitumen *(per boe)* [1]								
Sales price	**38.30**	47.92	**-**	-	**-**	-	**38.30**	47.92
Royalties	**4.97**	6.34	**-**	-	**-**	-	**4.97**	6.34
Operating costs	**12.96**	10.28	**-**	-	**-**	-	**12.96**	10.28
	20.37	31.30	**-**	-	**-**	-	**20.37**	31.30
Total Crude Oil *(per boe)* [1]								
Sales price	**43.06**	52.08	**73.79**	76.57	**75.14**	77.80	**56.31**	59.28
Royalties	**5.77**	7.28	**6.04**	1.82	**14.43**	16.35	**6.28**	6.44
Operating costs	**13.01**	10.95	**4.00**	4.97	**3.04**	2.41	**9.10**	9.07
	24.28	33.85	**63.75**	69.78	**57.67**	59.04	**40.93**	43.77
Natural Gas *(per mcfge)* [3]								
Sales price	**7.04**	6.23	**-**	-	**-**	-	**7.04**	6.23
Royalties	**1.37**	1.16	**-**	-	**-**	-	**1.37**	1.16
Operating costs	**1.35**	1.09	**-**	-	**-**	-	**1.35**	1.09
	4.32	3.98	**-**	-	**-**	-	**4.32**	3.98
Equivalent Unit *(per boe)* [1]								
Sales price	**42.78**	46.13	**73.79**	76.57	**75.14**	77.80	**52.56**	52.19
Royalties	**6.74**	7.15	**6.04**	1.82	**14.43**	16.35	**6.81**	6.61
Operating costs	**11.10**	9.17	**4.00**	4.97	**3.04**	2.41	**8.84**	8.24
	$ 24.94	$ 29.81	**$ 63.75**	$ 69.78	**$ 57.67**	$ 59.04	**$ 36.91**	$ 37.34

(1) *Includes associated co-products converted to boe.*
(2) *During the second quarter of 2007, White Rose royalties increased to 5% because the project, off the East Coast, achieved simple payout.*
(3) *Includes associated co-products converted to mcfge.*

Operating Netbacks (continued)

	Western Canada		East Coast		International		Total	
Six months ended June 30	**2007**	2006	**2007**	2006	**2007**	2006	**2007**	2006
Light Crude Oil *(per boe)* [(1)]								
Sales price	**$ 58.08**	$ 61.50	**$ 70.17**	$ 73.14	**$ 71.65**	$ 75.58	**$ 68.13**	$ 70.06
Royalties [(2)]	**6.26**	6.27	**4.10**	2.75	**12.36**	10.83	**5.26**	4.85
Operating costs	**12.82**	12.32	**3.52**	6.15	**3.98**	3.11	**5.24**	7.55
	39.00	42.91	**62.55**	64.24	**55.31**	61.64	**57.63**	57.66
Medium Crude Oil *(per boe)* [(1)]								
Sales price	**46.99**	47.83	**-**	-	**-**	-	**46.99**	47.83
Royalties	**8.17**	8.51	**-**	-	**-**	-	**8.17**	8.51
Operating costs	**13.03**	12.02	**-**	-	**-**	-	**13.03**	12.02
	25.79	27.30	**-**	-	**-**	-	**25.79**	27.30
Heavy Crude Oil & Bitumen *(per boe)* [(1)]								
Sales price	**37.98**	37.34	**-**	-	**-**	-	**37.98**	37.34
Royalties	**4.84**	4.71	**-**	-	**-**	-	**4.84**	4.71
Operating costs	**12.40**	10.76	**-**	-	**-**	-	**12.40**	10.76
	20.74	21.87	**-**	-	**-**	-	**20.74**	21.87
Total Crude Oil *(per boe)* [(1)]								
Sales price	**42.75**	43.32	**70.17**	73.14	**71.65**	75.58	**54.37**	52.12
Royalties	**5.65**	5.66	**4.10**	2.75	**12.36**	10.83	**5.39**	5.25
Operating costs	**12.57**	11.25	**3.52**	6.15	**3.98**	3.11	**8.79**	9.60
	24.53	26.41	**62.55**	64.24	**55.31**	61.64	**40.19**	37.27
Natural Gas *(per mcfge)* [(3)]								
Sales price	**7.03**	7.15	**-**	-	**-**	-	**7.03**	7.15
Royalties	**1.41**	1.54	**-**	-	**-**	-	**1.41**	1.54
Operating costs	**1.34**	1.04	**-**	-	**-**	-	**1.34**	1.04
	4.28	4.57	**-**	-	**-**	-	**4.28**	4.57
Equivalent Unit *(per boe)* [(1)]								
Sales price	**42.54**	43.14	**70.17**	73.14	**71.65**	75.58	**51.10**	49.14
Royalties	**6.73**	7.09	**4.10**	2.75	**12.36**	10.83	**6.21**	6.53
Operating costs	**10.82**	9.24	**3.52**	6.15	**3.98**	3.11	**8.59**	8.52
	$ 24.99	$ 26.81	**$ 62.55**	$ 64.24	**$ 55.31**	$ 61.64	**$ 36.30**	$ 34.09

(1) *Includes associated co-products converted to boe.*
(2) *During the second quarter of 2007, White Rose royalties increased to 5% because the project, off the East Coast, achieved simple payout.*
(3) *Includes associated co-products converted to mcfge.*

UPSTREAM CAPITAL EXPENDITURES

Capital expenditures during the second 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 June 30		Six months ended June 30	
(millions of dollars)	**2007**	2006	**2007**	2006
Exploration				
Western Canada	**$ 66**	$ 148	**$ 228**	$ 308
East Coast Canada and Frontier	**-**	3	**5**	23
International	**19**	36	**24**	36
	85	187	**257**	367
Development				
Western Canada	**353**	236	**736**	727
East Coast Canada	**60**	111	**114**	163
International	**5**	6	**5**	9
	418	353	**855**	899
	$ 503	$ 540	**$ 1,112**	$ 1,266

[1] *Excludes capitalized costs related to asset retirement obligations incurred during the period, capitalized administrative costs and capitalized interest.*

During the first six months of 2007, upstream capital expenditures were $1,112 million, $964 million (87%) in Western Canada, $119 million (11%) off the East Coast of Canada and $29 million (2%) offshore China, Indonesia and other international areas.

Western Canada

During the first six months of 2007, we invested $82 million on exploration in the foothills, deep basin and northern plains. We drilled 11 net wells in these regions resulting in 11 net natural gas wells. In the Lloydminster area of Alberta and Saskatchewan, from which the majority of our heavy crude oil is produced, we invested $246 million, primarily for exploitation and optimization.

We invested $122 million in the oil sands areas during the first six months of 2007, $39 million at Tucker where production is ramping up and $39 million on the Sunrise project. Front-end engineering design of the Sunrise project is currently 67% complete. We invested $44 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 quarters and six months ended June 30, 2007 and 2006. The data indicates that during the second quarter of 2007, 94% of the net exploration wells and 97% of the net development wells we drilled resulted in wells capable of commercial production.

Western Canada Wells Drilled		Three months ended June 30				Six months ended June 30			
		2007		2006		**2007**		2006	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**13**	**13**	7	7	**33**	**33**	29	29
	Gas	**4**	**3**	36	18	**69**	**59**	194	104
	Dry	**1**	**1**	3	3	**10**	**10**	18	17
		18	**17**	46	28	**112**	**102**	241	150
Development	Oil	**58**	**54**	69	57	**196**	**184**	179	160
	Gas	**6**	**4**	37	23	**174**	**141**	262	216
	Dry	**2**	**2**	2	2	**12**	**12**	11	11
		66	**60**	108	82	**382**	**337**	452	387
Total		**84**	**77**	154	110	**494**	**439**	693	537

Off the East Coast of Canada

During the first six months of 2007, capital expenditures in the region off the East Coast of Canada totalled $119 million. During June 2007, the seventh production well at the White Rose oil field was completed. Exploration expenditures in the East Coast offshore areas were $5 million during the first half of 2007 as drilling locations were being evaluated.

International

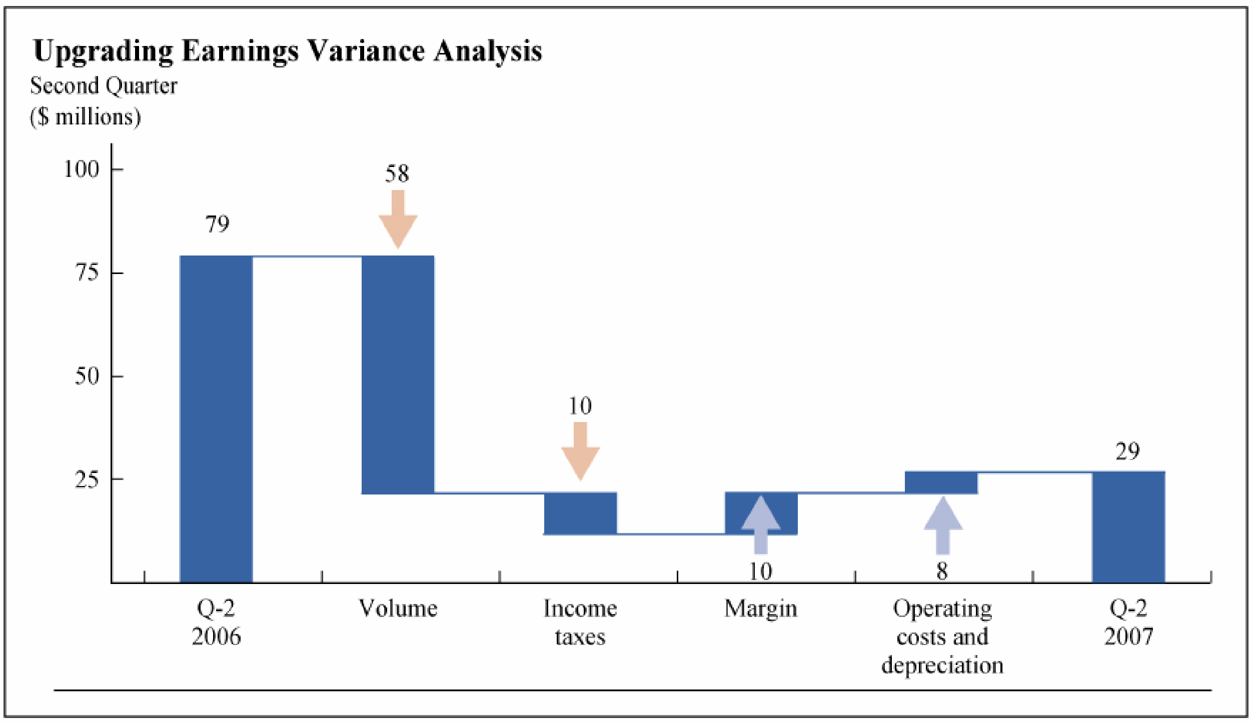
During the first half of 2007, we invested $24 million on international exploration for drilling location evaluations for the South and East China Seas and on the East Bawean II exploration block in the Java Sea. Capital expenditures on development were $5 million in the first half of 2007 primarily to advance the Madura natural gas and liquids project in Indonesia.

4.2 MIDSTREAM

Upgrading Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2007**	2006	**2007**	2006
Gross margin		**$ 89**	$ 136	**$ 227**	$ 344
Operating costs		**47**	53	**105**	119
Other recoveries		**(1)**	(2)	**(2)**	(3)
Depreciation and amortization		**4**	6	**10**	12
Income taxes		**10**	-	**34**	44
Earnings		**$ 29**	$ 79	**$ 80**	$ 172
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**36.1**	68.8	**52.5**	70.1
Synthetic crude oil sales	*(mbbls/day)*	**32.9**	56.9	**45.3**	60.2
Upgrading differential	*($/bbl)*	**$ 30.41**	$ 22.73	**$ 26.42**	$ 28.73
Unit margin	*($/bbl)*	**$ 29.74**	$ 26.35	**$ 27.64**	$ 31.61
Unit operating cost [(2)]	*($/bbl)*	**$ 14.37**	$ 8.39	**$ 11.05**	$ 9.33

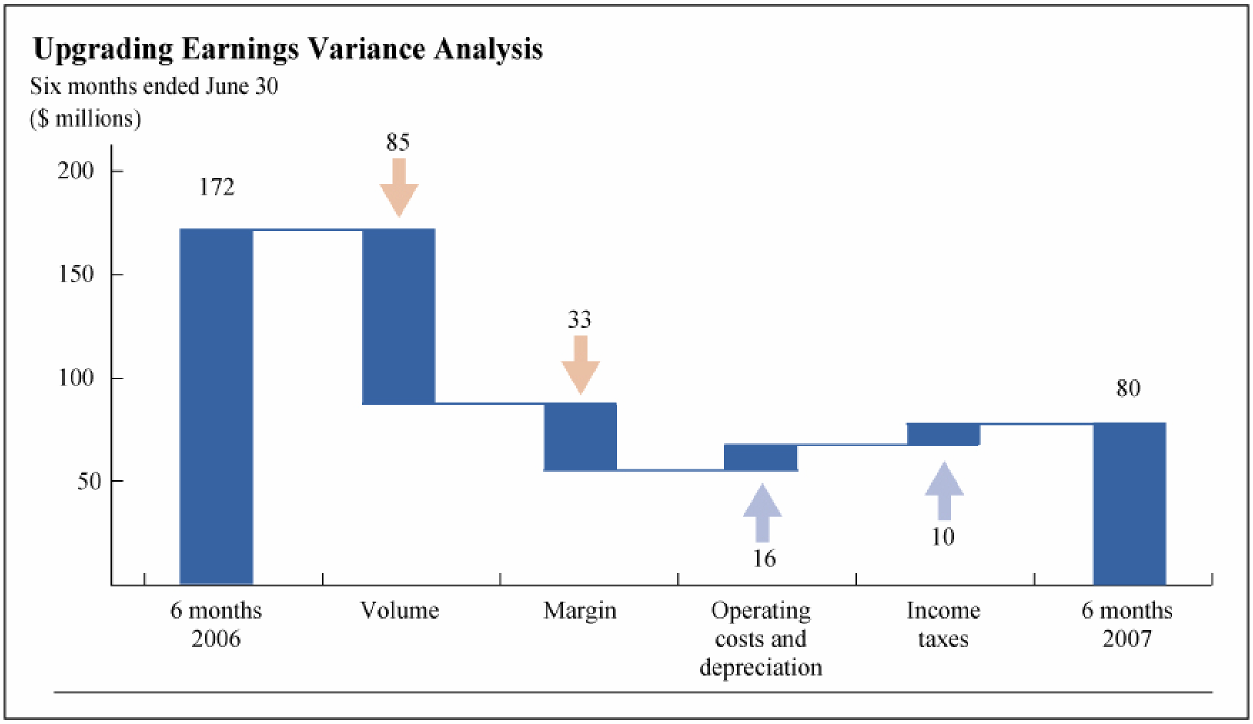
[(1)] *Throughput includes diluent returned to the field.*
[(2)] *Based on throughput.*

Second Quarter



Upgrading earnings in the second quarter of 2007 were $29 million, a decrease of $50 million from the second quarter of 2006 due primarily to a scheduled turnaround to perform maintenance and inspection. The turnaround, which shut the plant down for 49 days from May 10 to June 28, resulted in lower throughput in the second quarter of 2007 compared with the same quarter in 2006. The turnaround time was extended from 40 days to install two new coke drums. Operating costs during the second quarter of 2007 were $14.37/bbl compared with $8.39/bbl in the same quarter in 2006. Higher unit operating costs resulted from lower throughput.

Six Months



Upgrading earnings were lower in the first six months of 2007 than the corresponding period in 2006 due to the 49 day turnaround and also a lower differential between heavy crude oil and synthetic crude oil. Operating costs during the first six months of 2007 were $11.05/bbl compared with $9.33/bbl in the same period in 2006.

Infrastructure and Marketing Earnings Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)	**2007**	2006	**2007**	2006
Gross margin - pipeline	**$ 28**	$ 28	**$ 54**	$ 54
- other infrastructure and marketing	**48**	52	**120**	120
	76	80	**174**	174
Other expenses	**-**	3	**4**	5
Depreciation and amortization	**7**	5	**14**	11
Income taxes	**21**	11	**48**	40
Earnings	**$ 48**	$ 61	**$ 108**	$ 118
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**506**	480	**500**	490

Second Quarter

Infrastructure and marketing earnings in the second quarter of 2007 decreased by $13 million compared with the second quarter of 2006 primarily due to lower margins on Lloyd Blend marketing and higher income taxes.

Six Months

Infrastructure and marketing earnings in the first six months of 2007 were marginally lower compared with the same period in 2006. Higher earnings from cogeneration operations were offset by lower Lloyd Blend margins and higher income taxes.

MIDSTREAM CAPITAL EXPENDITURES

Midstream capital expenditures totalled $161 million in the first six months of 2007: $121 million at the Lloydminster Upgrader, primarily for front-end engineering design for a proposed expansion, a small debottleneck project and reliability projects. The remaining $40 million was primarily spent on a pipeline extension between Lloydminster and Hardisty, Alberta.

4.3 REFINED PRODUCTS

Refined Products Earnings Summary		Three months ended June 30		Six months ended June 30	
(millions of dollars, except where indicated)		**2007**	2006	**2007**	2006
Gross margin - fuel sales		**$ 63**	$ 57	**$ 105**	$ 79
- ancillary sales		**10**	8	**19**	16
- asphalt sales		**36**	32	**49**	53
		109	97	**173**	148
Operating and other expenses		**20**	19	**38**	35
Depreciation and amortization		**15**	13	**31**	23
Income taxes		**21**	13	**31**	22
Earnings		**$ 53**	$ 52	**$ 73**	$ 68
Selected operating data:					
Number of fuel outlets				**504**	506
Light oil sales	*(million litres/day)*	**8.6**	8.6	**8.8**	8.6
Light oil retail sales per outlet	*(thousand litres/day)*	**13.3**	12.2	**12.8**	12.5
Prince George refinery throughput	*(mbbls/day)*	**8.4**	3.7	**9.7**	6.5
Asphalt sales	*(mbbls/day)*	**19.5**	24.9	**18.4**	21.3
Lloydminster refinery throughput	*(mbbls/day)*	**18.5**	25.4	**21.6**	26.2
Ethanol production	*(thousand litres/day)*	**305.9**	25.2	**313.7**	25.6

Second Quarter

Refined Products earnings in the second quarter of 2007 were marginally higher compared with the second quarter of 2006 primarily due to the addition of ethanol sales from the new Lloydminster ethanol plant, higher restaurant and convenience store income and higher asphalt product margins partially offset by lower fuel margins and sales volume, lower asphalt sales volume and higher depreciation created by the startup of the Lloydminster ethanol plant.

Six Months

Refined Products earnings in the first six months of 2007 increased by $5 million compared with the corresponding period of 2006. Higher earnings resulted from the ethanol sales from the Lloydminster ethanol plant, higher fuel and asphalt product margins and higher restaurant and convenience store income partially offset by lower asphalt sales volume and higher depreciation created by the startup of the Lloydminster ethanol plant.

REFINED PRODUCTS CAPITAL EXPENDITURES

Refined Products capital expenditures totalled $79 million during the first six months of 2007. The Minnedosa ethanol plant currently under construction accounted for $38 million, $25 million for marketing location upgrades and construction and $16 million for debottleneck and upgrade projects at the Lloydminster asphalt refinery, Prince George refinery, Lloydminster ethanol plant and asphalt distribution facilities.

4.4 CORPORATE

Corporate Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars) income (expense)	**2007**	2006	**2007**	2006
Intersegment eliminations - net	**$ (33)**	$ (23)	**$ (58)**	$ (14)
Administration expenses	**(10)**	(8)	**(21)**	(12)
Stock-based compensation	**(43)**	(15)	**(64)**	(85)
Accretion	**(1)**	(1)	**(2)**	(1)
Other - net	**(1)**	(4)	**(6)**	(8)
Depreciation and amortization	**(7)**	(5)	**(12)**	(11)
Interest on debt	**(27)**	(32)	**(51)**	(70)
Interest capitalized	**5**	10	**8**	21
Foreign exchange - realized	**(35)**	(8)	**(29)**	19
Foreign exchange - unrealized	**71**	40	**66**	18
Income taxes	**36**	10	**63**	53
Earnings (loss)	**$ (45)**	$ (36)	**$ (106)**	$ (90)

Foreign Exchange Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2007**	2006	**2007**	2006
(Gain) loss on translation of U.S. dollar denominated long-term debt				
Realized	**$ -**	$ 1	**$ -**	$ (30)
Unrealized	**(101)**	(67)	**(115)**	(37)
	(101)	(66)	**(115)**	(67)
Cross currency swaps	**32**	27	**36**	26
Other losses	**33**	7	**42**	4
	$ (36)	$ (32)	**$ (37)**	$ (37)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.867**	U.S. $0.857	**U.S. $0.858**	U.S. $0.858
At end of period	**U.S. $0.940**	U.S. $0.897	**U.S. $0.940**	U.S. $0.897

CORPORATE CAPITAL EXPENDITURES

During the first six months of 2007, corporate capital expenditures amounted to $12 million for various office space and facilities upgrades.

CONSOLIDATED INCOME TAXES

During the second quarter of 2007, consolidated income taxes consisted of $66 million of current taxes and $205 million of future taxes compared with current taxes of $210 million and future tax recovery of $229 million in the same period of 2006.

Lower current income taxes and higher future income taxes in the second quarter of 2007 were due to the deferral of White Rose income. Future income taxes in the second quarter of 2006 included a tax benefit of $328 million for changes in the tax rates of the governments of Canada, Alberta and Saskatchewan. Future income taxes in the second quarter of 2007 were reduced by a $30 million benefit in respect of a rate reduction by the Government of Canada.

Quarterly Financial Summary

	Three months ended							
(millions of dollars, except per share amounts and ratios)	**June 30 2007**	March 31 2007	Dec. 31 2006	Sept. 30 2006	June 30 2006	March 31 2006	Dec. 31 2005	Sept. 30 2005
Sales and operating revenues, net of royalties	**$ 3,163**	$ 3,244	$ 3,084	$ 3,436	$ 3,040	$ 3,104	$ 3,207	$ 2,594
Segmented earnings								
Upstream	**$ 636**	$ 580	$ 453	$ 608	$ 822	$ 412	$ 533	$ 445
Midstream	**77**	111	105	87	140	150	135	61
Refined Products	**53**	20	10	28	52	16	17	27
Corporate and eliminations	**(45)**	(61)	(26)	(41)	(36)	(54)	(16)	23
Net earnings	**$ 721**	$ 650	$ 542	$ 682	$ 978	$ 524	$ 669	$ 556
Per share - Basic and diluted [(1)]	**$ 0.85**	$ 0.77	$ 0.64	$ 0.80	$ 1.15	$ 0.62	$ 0.79	$ 0.66
Cash flow from operations	**1,257**	1,324	1,207	1,224	1,103	967	1,197	944
Per share - Basic and diluted [(1)]	**1.48**	1.56	1.42	1.44	1.30	1.14	1.41	1.11
Ordinary quarterly dividend per common share [(1)]	**0.25**	0.25	0.25	0.25	0.125	0.125	0.125	0.07
Special dividend per common share [(1)]	**-**	0.25	-	-	-	-	0.50	-
Total assets	**17,969**	17,781	17,933	17,324	16,328	15,855	15,716	14,670
Total long-term debt including current portion	**1,423**	1,527	1,611	1,722	1,722	1,838	1,886	1,896
Return on equity [(2)] *(percent)*	**27.1**	32.1	31.8	34.2	34.8	29.6	29.2	22.9
Return on average capital employed [(2)] *(percent)*	**23.8**	27.3	27.0	28.7	28.2	23.2	22.8	17.9

[(1)] *Amounts prior to June 30, 2007 as restated. Refer to Note 9 to the Consolidated Financial Statements.*
[(2)] *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 second 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 Second 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	$ 65.03	*U.S. $1.00/bbl*	96	0.11	66	0.08
NYMEX benchmark natural gas price [(1)]	$ 7.55	*U.S. $0.20/mmbtu*	30	0.04	21	0.02
WTI/Lloyd crude blend differential [(2)]	$ 20.36	*U.S. $1.00/bbl*	(40)	(0.05)	(28)	(0.03)
Exchange rate (U.S. $ per Cdn $) [(3)]	$ 0.911	*U.S. $0.01*	(71)	(0.08)	(50)	(0.06)
Refined Products						
Light oil margins	$ 0.07	*Cdn $0.005/litre*	16	0.02	10	0.01
Asphalt margins	$ 18.49	*Cdn $1.00/bbl*	7	0.01	5	0.01
Consolidated						
Period end translation of U.S. $ debt (U.S. $ per Cdn $)	$ 0.940 [(4)]	*U.S. $0.01*			7	0.01

[(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 June 30, 2007.*
[(5)] *Based on 848.8 million common shares outstanding as of June 30, 2007.*

5.0 LIQUIDITY AND CAPITAL RESOURCES

During the second quarter of 2007, cash flow from operating activities financed all of our capital requirements and dividend payment. At June 30, 2007, we had $1.5 billion in unused committed credit facilities.

Cash Flow Summary	Three months ended June 30		Six months ended June 30	
(millions of dollars, except ratios)	**2007**	2006	**2007**	2006
Cash flow - operating activities	**$ 1,136**	$ 1,299	**$ 1,808**	$ 2,430
- financing activities	**$ (454)**	$ (409)	**$ (676)**	$ (848)
- investing activities	**$ (549)**	$ (773)	**$ (1,441)**	$ (1,633)
Financial Ratios				
Debt to capital employed *(percent)*			**12.1**	16.3
Corporate reinvestment ratio *(percent)* [(1) (2)]			**54**	78

(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 second quarter of 2007, cash generated from operating activities amounted to $1.1 billion compared with $1.3 billion in the second quarter of 2006. Lower cash flow from operating activities was primarily due to a decrease in non-cash working capital resulting primarily from an increase in prepaid expenditures.

5.2 FINANCING ACTIVITIES

In the second quarter of 2007, cash used in financing activities amounted to $454 million compared with $409 million in the second quarter of 2006. During the second quarter of 2007, cash was used for dividends and change in non-cash working capital primarily related to the sale of receivables. 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 second quarter of 2007, cash used in investing activities amounted to $549 million compared with $773 million in the second quarter of 2006. Cash invested in both periods was used primarily for capital expenditures, partially offset by asset sales.

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 June 30, 2007, our working capital was $372 million compared with a deficiency of $495 million at December 31, 2006. 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)	**June 30 2007**	Dec. 31 2006	Change	
Current assets				
Cash and cash equivalents	**$ 133**	$ 442	$ (309)	Tax payment
Accounts receivable	**1,138**	1,284	(146)	Lower gas volumes/prices and sale of accounts receivable
Inventories	**519**	428	91	Higher gas storage and Terra Nova crude volumes
Prepaid expenses	**182**	25	157	Deposit for acquisition of Lima refinery
	1,972	2,179	(207)	
Current liabilities				
Accounts payable	**915**	1,268	353	Lower capital and operating cost accruals
Accrued interest payable	**19**	27	8	
Income taxes payable	**-**	615	615	Tax payment made
Other accrued liabilities	**666**	664	(2)	
Long-term debt due within one year	**-**	100	100	Payment of medium-term notes
	1,600	2,674	1,074	
Working capital	**$ 372**	$ (495)	$ 867	

Sources and Uses of Cash

(millions of dollars)	Six months ended June 30 **2007**	Year ended December 31 2006
Cash sourced		
Cash flow from operations [(1)]	**$ 2,581**	$ 4,501
Debt issue	**1,867**	1,226
Asset sales	**327**	34
Proceeds from exercise of stock options	**4**	3
	4,779	5,764
Cash used		
Capital expenditures	**1,381**	3,171
Debt repayment	**1,967**	1,493
Special dividend on common shares	**212**	-
Ordinary dividends on common shares	**424**	636
Settlement of asset retirement obligations	**21**	36
Settlement of cross currency swap	**-**	47
Other	**38**	13
	4,043	5,396
Net cash	**736**	368
Decrease in non-cash working capital	**(1,045)**	(94)
Increase (decrease) in cash and cash equivalents	**(309)**	274
Cash and cash equivalents - beginning of period	**442**	168
Cash and cash equivalents - end of period	**$ 133**	$ 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 [1]

(millions of dollars)	June 30, 2007 Outstanding (U.S. $)	(Cdn $)	Available (Cdn $)
Short-term bank debt	$ -	$ -	$ 199
Long-term bank debt			
Syndicated credit facility	-	-	1,250
Bilateral credit facilities	-	-	150
Medium-term notes [2]	-	200	
Capital securities	225	239	
U.S. public notes	900	957	
	1,125	1,396	1,599
Fair value adjustment [2]	-	1	
Debt issue costs [3]	-	(13)	
Unwound interest rate swaps [4]	-	39	
Total short-term and long-term debt	$ 1,125	$ 1,423	$ 1,599
Common shares, retained earnings and accumulated other comprehensive income		$ 10,359	

[1] Does not include U.S. $1.5 billion bridge financing for the Lima refinery acquisition.
[2] 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.
[3] 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.
[4] 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 June 30, 2007, we had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. A total of $71 million of our borrowing credit facilities were used in support of outstanding letters of credit and an additional $34 million of letters of credit were outstanding at June 30, 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.

At a special meeting of the shareholders on June 27, 2007, the shareholders approved a two-for-one share split of our issued and outstanding common shares. On June 27, 2007, the Company filed Articles of Amendment to effect the share split. All references to common share amounts, including common shares issued and outstanding, basic and diluted earnings per share, dividend per share, weighted average number of common shares outstanding and stock options granted, exercised, surrendered and forfeited have been retroactively restated to reflect the impact of the two-for-one share split. The common shares commenced trading on the Toronto Stock Exchange reflecting this split on July 9, 2007.

During the second quarter of 2007, we arranged short-term bridge financing from several banks to facilitate closing the acquisition of the Lima refinery on July 3, 2007. The bridge financing provided U.S. $1.5 billion while the remaining funds required were drawn under existing credit facilities. We plan to refinance the bridge financing by issuing securities in the long-term debt markets.

5.5 CREDIT RATINGS

Our credit ratings remain unchanged and 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 June 30, 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 June 30, 2007, $60 million of accounts receivable have been 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 six 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 six 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 filed on the Canadian Securities Administrators' web site, www.sedar.com, the U.S. Securities and 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.

INTEREST RATE RISK MANAGEMENT

In the first six 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 $2 million in the first six 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 six 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 $2 million offset to interest expense in the first six months of 2007.

FOREIGN CURRENCY RISK MANAGEMENT

At June 30, 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 June 30, 2007, the cost of a U.S. dollar in Canadian currency was $1.0634.

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 June 30, 2007, 86% or $1.2 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 59% 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 International Financial Reporting Standards. 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 [(1)]

(in thousands, except per share amounts)		Six months ended June 30 **2007**	Year ended December 31 2006
Share price [(2)]	High	**$ 46.65**	$ 41.50
	Low	**$ 35.40**	$ 29.00
	Close at end of period	**$ 43.85**	$ 39.02
Average daily trading volume		**1,061**	1,210
Weighted average number of common shares outstanding			
	Basic and diluted	**848,637**	848,412
Issued and outstanding at end of period [(3)]			
Number of common shares		**848,849**	848,538
Number of stock options		**32,205**	11,656
Number of stock options exercisable		**5,435**	4,464

(1) *2006 amounts as restated. Refer to Note 9 to the Consolidated Financial Statements.*
(2) *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.*
(3) *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 June 30, 2007 to July 11, 2007. During this period, 18 thousand stock options were surrendered for cash and 279 thousand options were forfeited. At July 11, 2007, the Company had 848,849 thousand common shares outstanding and there were 31,908 thousand stock options outstanding, of which 5,417 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)		Six months ended June 30 **2007**	Year ended December 31 2006
Non-GAAP	Cash flow from operations	**$ 2,581**	$ 4,501
	Settlement of asset retirement obligations	**(21)**	(36)
	Change in non-cash working capital	**(752)**	544
GAAP	Cash flow - operating activities	**$ 1,808**	$ 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 U.S. 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, unless the context indicates otherwise, 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 June 30, 2007 are compared with results for the three months ended June 30, 2006 and results for the six months ended June 30, 2007 are compared with results for the six months ended June 30, 2006. Discussions with respect to Husky's financial position as at June 30, 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.

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*

Terms

Bitumen	*A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. It is more viscous than 10 degrees API*
Capital Employed	*Short- and long-term debt and shareholders' equity*
Capital Expenditures	*Excludes capitalized administrative expenses, capitalized interest, proceeds and other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Carbonate	*Sedimentary rock primarily composed of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite) which forms many petroleum reservoirs*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Coalbed Methane	*Methane (CH_4), the principal component of natural gas, is adsorbed in the pores of coal seams*
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*
Design Rate Capacity	*Maximum continuous rated output of a plant based on its design*
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*
Equity	*Shares and retained earnings*
Feedstock	*Raw materials which are processed into petroleum products*
Front-end Engineering Design	*Preliminary engineering and design planning, which among other things, identifies project objectives, scope, alternatives, specifications, risks, costs, schedule and economics*
Glory Hole	*An excavation in the seabed where the wellheads and other equipment are situated to protect them from scouring icebergs*
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*
Gross Reserves/Production	*A company's working interest share of reserves/production before deduction of royalties*
Hectare	*One hectare is equal to 2.47 acres*
Nameplate Capacity	*The maximum rated output at which a plant or other equipment was designed and constructed to safely and efficiently operate under specified conditions*
Near-month Prices	*Prices quoted for contracts for settlement during the next month*
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*
Polymer	*A substance which has a molecular structure built up mainly or entirely of many similar units bonded together*
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*
Surfactant	*A substance that tends to reduce the surface tension of a liquid in which it is dissolved*
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 are 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 and East Coast drilling, development and production plans, our production plans for the Tucker in-situ oil sands project, our Sunrise oil sands project design schedule and site preparation schedule, our Northwest Territories drilling program, the schedule 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, schedule of our Lloydminster Upgrader expansion design plans and our plans to review options in respect of reconfiguring and expanding the Lima refinery. 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.*

These risks, uncertainties and other factors are discussed in our Annual Information Form and our Form 40-F, available at www.sedar.com and www.sec.gov, respectively.

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)	**June 30 2007**	December 31 2006
	(unaudited)	
Assets		
Current assets		
Cash and cash equivalents	**$ 133**	$ 442
Accounts receivable	**1,138**	1,284
Inventories	**519**	428
Prepaid expenses	**182**	25
	1,972	2,179
Property, plant and equipment - (full cost accounting)	**26,439**	25,552
Less accumulated depletion, depreciation and amortization	**10,708**	10,002
	15,731	15,550
Goodwill	**160**	160
Other assets	**106**	44
	$ 17,969	$ 17,933
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 1,600**	$ 2,574
Long-term debt due within one year *(note 6)*	**-**	100
	1,600	2,674
Long-term debt *(note 6)*	**1,423**	1,511
Other long-term liabilities *(note 7)*	**789**	756
Future income taxes	**3,798**	3,372
Commitments and contingencies *(note 8)*		
Shareholders' equity		
Common shares *(note 9)*	**3,547**	3,533
Retained earnings	**6,826**	6,087
Accumulated other comprehensive income	**(14)**	-
	10,359	9,620
	$ 17,969	$ 17,933
Common shares outstanding *(millions) (note 9)*	**848.8**	848.5

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 June 30 **2007**	Three months ended June 30 2006	Six months ended June 30 **2007**	Six months ended June 30 2006
Sales and operating revenues, net of royalties	**$ 3,163**	$ 3,040	**$ 6,407**	$ 6,144
Costs and expenses				
Cost of sales and operating expenses	**1,701**	1,638	**3,480**	3,465
Selling and administration expenses	**52**	50	**90**	77
Stock-based compensation	**43**	15	**64**	85
Depletion, depreciation and amortization	**440**	383	**873**	762
Interest - net *(note 6)*	**22**	22	**43**	49
Foreign exchange *(note 6)*	**(36)**	(32)	**(37)**	(37)
Other - net	**(51)**	5	**(45)**	8
	2,171	2,081	**4,468**	4,409
Earnings before income taxes	**992**	959	**1,939**	1,735
Income taxes				
Current	**66**	210	**138**	414
Future	**205**	(229)	**430**	(181)
	271	(19)	**568**	233
Net earnings	**721**	978	**1,371**	1,502
Other comprehensive income, net of tax *(note 3)*	**2**	-	**4**	-
Comprehensive income *(note 3)*	**$ 723**	$ 978	**$ 1,375**	$ 1,502
Earnings per share				
Basic and diluted *(note 9)*	**$ 0.85**	$ 1.15	**$ 1.61**	$ 1.77
Weighted average number of common shares outstanding *(millions)*				
Basic and diluted *(note 9)*	**848.7**	848.4	**848.6**	848.3

Consolidated Statements of Retained Earnings and Accumulated Other Comprehensive Income

(millions of dollars) (unaudited)	Three months ended June 30 **2007**	Three months ended June 30 2006	Six months ended June 30 **2007**	Six months ended June 30 2006
Retained earnings, beginning of period	**$ 6,317**	$ 4,415	**$ 6,087**	$ 3,997
Net earnings	**721**	978	**1,371**	1,502
Dividends on common shares - ordinary	**(212)**	(106)	**(424)**	(212)
- special	**-**	-	**(212)**	-
Adoption of financial instruments *(notes 3, 11)*	**-**	-	**4**	-
Retained earnings, end of period	**$ 6,826**	$ 5,287	**$ 6,826**	$ 5,287
Accumulated other comprehensive income, beginning of period	**$ (16)**	$ -	**$ -**	$ -
Adoption of financial instruments *(notes 3, 11)*	**-**	-	**(18)**	-
Other comprehensive income, net of tax *(note 3)*	**2**	-	**4**	-
Accumulated other comprehensive income, end of period	**$ (14)**	$ -	**$ (14)**	$ -

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

Consolidated Statements of Cash Flows

(millions of dollars) (unaudited)	Three months ended June 30 **2007**	Three months ended June 30 2006	Six months ended June 30 **2007**	Six months ended June 30 2006
Operating activities				
Net earnings	**$ 721**	$ 978	**$ 1,371**	$ 1,502
Items not affecting cash				
Accretion *(note 7)*	**10**	9	**22**	18
Depletion, depreciation and amortization	**440**	383	**873**	762
Future income taxes	**205**	(229)	**430**	(181)
Foreign exchange	**(69)**	(41)	**(79)**	(42)
Other	**(50)**	3	**(36)**	11
Settlement of asset retirement obligations	**(7)**	(6)	**(21)**	(14)
Change in non-cash working capital *(note 4)*	**(114)**	202	**(752)**	374
Cash flow - operating activities	**1,136**	1,299	**1,808**	2,430
Financing activities				
Bank operating loans financing - net	**(83)**	(132)	**-**	-
Long-term debt issue	**1,432**	251	**1,867**	1,226
Long-term debt repayment	**(1,432)**	(300)	**(1,967)**	(1,322)
Proceeds from exercise of stock options	**3**	-	**4**	1
Dividends on common shares	**(212)**	(106)	**(636)**	(212)
Change in non-cash working capital *(note 4)*	**(162)**	(122)	**56**	(541)
Cash flow - financing activities	**(454)**	(409)	**(676)**	(848)
Available for investing	**682**	890	**1,132**	1,582
Investing activities				
Capital expenditures	**(647)**	(683)	**(1,381)**	(1,543)
Asset sales	**327**	1	**327**	33
Other	**(36)**	(12)	**(38)**	(13)
Change in non-cash working capital *(note 4)*	**(193)**	(79)	**(349)**	(110)
Cash flow - investing activities	**(549)**	(773)	**(1,441)**	(1,633)
Increase (decrease) in cash and cash equivalents	**133**	117	**(309)**	(51)
Cash and cash equivalents, beginning of period	**-**	-	**442**	168
Cash and cash equivalents, end of period	**$ 133**	$ 117	**$ 133**	$ 117

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

Notes to the Consolidated Financial Statements

Six months ended June 30, 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 June 30												
Sales and operating revenues, net of royalties	**$ 1,593**	$ 1,451	**$ 229**	$ 404	**$ 2,521**	$ 2,267	**$ 709**	$ 674	**$ (1,889)**	$ (1,756)	**$ 3,163**	$ 3,040
Costs and expenses												
Operating, cost of sales, selling, general and other	**295**	308	**186**	319	**2,445**	2,190	**620**	596	**(1,801)**	(1,705)	**1,745**	1,708
Depletion, depreciation and amortization	**407**	354	**4**	6	**7**	5	**15**	13	**7**	5	**440**	383
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**22**	22	**22**	22
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(36)**	(32)	**(36)**	(32)
	702	662	**190**	325	**2,452**	2,195	**635**	609	**(1,808)**	(1,710)	**2,171**	2,081
Earnings (loss) before income taxes	**891**	789	**39**	79	**69**	72	**74**	65	**(81)**	(46)	**992**	959
Current income taxes	**3**	156	**-**	29	**29**	20	**7**	3	**27**	2	**66**	210
Future income taxes	**252**	(189)	**10**	(29)	**(8)**	(9)	**14**	10	**(63)**	(12)	**205**	(229)
Net earnings (loss)	**$ 636**	$ 822	**$ 29**	$ 79	**$ 48**	$ 61	**$ 53**	$ 52	**$ (45)**	$ (36)	**$ 721**	$ 978
Capital expenditures - Three months ended June 30 [2]	**$ 503**	$ 540	**$ 74**	$ 38	**$ 3**	$ 11	**$ 41**	$ 76	**$ 8**	$ (1)	**$ 629**	$ 664
Six months ended June 30												
Sales and operating revenues, net of royalties	**$ 3,158**	$ 2,738	**$ 588**	$ 809	**$ 5,076**	$ 4,731	**$ 1,327**	$ 1,220	**$ (3,742)**	$ (3,354)	**$ 6,407**	$ 6,144
Costs and expenses												
Operating, cost of sales, selling, general and other	**618**	619	**464**	581	**4,906**	4,562	**1,192**	1,107	**(3,591)**	(3,234)	**3,589**	3,635
Depletion, depreciation and amortization	**806**	705	**10**	12	**14**	11	**31**	23	**12**	11	**873**	762
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**43**	49	**43**	49
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**(37)**	(37)	**(37)**	(37)
	1,424	1,324	**474**	593	**4,920**	4,573	**1,223**	1,130	**(3,573)**	(3,211)	**4,468**	4,409
Earnings (loss) before income taxes	**1,734**	1,414	**114**	216	**156**	158	**104**	90	**(169)**	(143)	**1,939**	1,735
Current income taxes	**25**	299	**1**	53	**45**	39	**15**	12	**52**	11	**138**	414
Future income taxes	**493**	(119)	**33**	(9)	**3**	1	**16**	10	**(115)**	(64)	**430**	(181)
Net earnings (loss)	**$ 1,216**	$ 1,234	**$ 80**	$ 172	**$ 108**	$ 118	**$ 73**	$ 68	**$ (106)**	$ (90)	**$ 1,371**	$ 1,502
Capital employed - As at June 30	**$ 9,786**	$ 9,274	**$ 816**	$ 691	**$ 852**	$ 353	**$ 796**	$ 585	**$ (468)**	$ (367)	**$ 11,782**	$ 10,536
Capital expenditures - Six months ended June 30 [2]	**$ 1,112**	$ 1,266	**$ 121**	$ 75	**$ 40**	$ 12	**$ 79**	$ 138	**$ 12**	$ 8	**$ 1,364**	$ 1,499
Total assets - As at June 30	**$13,974**	$13,277	**$ 1,193**	$ 1,064	**$ 1,147**	$ 732	**$ 1,304**	$ 998	**$ 351**	$ 257	**$ 17,969**	$ 16,328

(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.

(2) Excludes capitalized costs related to asset retirement obligations incurred during the period, capitalized administrative costs and capitalized interest.

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.

c) Inventories

The Company has assessed CICA section 3031, "Inventories," which is effective January 1, 2008 and has determined that there will be no impact to the financial statements.

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

	Three months ended June 30		Six months ended June 30	
	2007	2006	**2007**	2006
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 147**	$ 5	**$ 149**	$ 109
Inventories	**(99)**	(26)	**(91)**	6
Prepaid expenses	**(143)**	(23)	**(144)**	(19)
Accounts payable and accrued liabilities	**(374)**	45	**(959)**	(373)
Change in non-cash working capital	**$ (469)**	$ 1	**$ (1,045)**	$ (277)
Relating to:				
Operating activities	**$ (114)**	$ 202	**$ (752)**	$ 374
Financing activities	**(162)**	(122)	**56**	(541)
Investing activities	**(193)**	(79)	**(349)**	(110)
b) Other cash flow information:				
Cash taxes paid	**$ 72**	$ 44	**$ 840**	$ 173
Cash interest paid	**39**	47	**62**	79

Note 5 Bank Operating Loans

At June 30, 2007, the Company had unsecured short-term borrowing lines of credit with banks totalling $270 million (December 31, 2006 - $220 million). As at June 30, 2007 and December 31, 2006, there were no bank operating loans outstanding. As at June 30, 2007, letters of credit under these lines of credit totalled $71 million (December 31, 2006 - $19 million).

Note 6 Long-term Debt

	Maturity	June 30 2007	Dec. 31 2006	June 30 2007	Dec. 31 2006
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Medium-term notes [(1)]	2009	**$ 201**	$ 300	**$ -**	$ -
6.25% notes	2012	**425**	466	**400**	400
7.55% debentures	2016	**213**	233	**200**	200
6.15% notes	2019	**319**	350	**300**	300
8.90% capital securities	2028	**239**	262	**225**	225
Debt issue costs [(2)]		**(13)**	-	**-**	-
Unwound interest rate swaps [(3)]		**39**	-	**-**	-
Total long-term debt		**1,423**	1,611	**$1,125**	$ 1,125
Amount due within one year		**-**	(100)		
		$ 1,423	$ 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.

During the second quarter of 2007, the Company arranged short-term bridge financing from several banks to facilitate closing the acquisition of the Lima refinery on July 3, 2007. The bridge financing provided U.S. $1.5 billion while the remaining funds required were drawn under existing credit facilities. The Company plans to refinance the bridge financing by issuing securities in the long-term debt markets.

Interest - net consisted of:

	Three months ended June 30 2007	Three months ended June 30 2006	Six months ended June 30 2007	Six months ended June 30 2006
Long-term debt	**$ 26**	$ 31	**$ 54**	$ 68
Short-term debt	**2**	2	**3**	3
	28	33	**57**	71
Amount capitalized	**(5)**	(10)	**(8)**	(21)
	23	23	**49**	50
Interest income	**(1)**	(1)	**(6)**	(1)
	$ 22	$ 22	**$ 43**	$ 49

Foreign exchange consisted of:

	Three months ended June 30		Six months ended June 30	
	2007	2006	**2007**	2006
Gain on translation of U.S. dollar denominated long-term debt	**$ (101)**	$ (66)	**$ (115)**	$ (67)
Cross currency swaps	**32**	27	**36**	26
Other losses	**33**	7	**42**	4
	$ (36)	$ (32)	**$ (37)**	$ (37)

Note 7 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Six months ended June 30	
	2007	2006
Asset retirement obligations at beginning of period	**$ 622**	$ 557
Liabilities incurred	**16**	10
Liabilities disposed	**(14)**	-
Liabilities settled	**(21)**	(14)
Accretion	**22**	18
Asset retirement obligations at end of period	**$ 625**	$ 571

At June 30, 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.

On June 27, 2007, the Company filed Articles of Amendment to implement a two-for-one share split of its issued and outstanding common shares. The share split was approved at a special meeting of the shareholders on June 27, 2007. All references to common share amounts, including common shares issued and outstanding, basic and diluted earnings per share, dividend per share, weighted average number of common shares outstanding and stock options granted, exercised, surrendered and forfeited have been retroactively restated to reflect the impact of the two-for-one share split.

Common Shares

Changes to issued common shares were as follows:

	Six months ended June 30			
	2007		2006	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of period	848,537,018	$ 3,533	848,250,156	$ 3,523
Options exercised	311,592	14	124,530	4
Balance at June 30	**848,848,610**	**$ 3,547**	848,374,686	$ 3,527

Stock Options

In accordance with the Company's stock option plan, common share options may be granted to directors, officers and certain other employees. The stock option plan is a tandem plan that provides the stock option holder with the right to exercise the option or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the date of the award. When the option is surrendered for cash, the cash payment is the difference between the weighted average trading price of the Company's common shares on the trading day prior to the surrender date and the exercise price of the option. Under the stock option plan, the options awarded have a maximum term of five years and vest over three years on the basis of one-third per year.

Effective February 26, 2007, the Board of Directors approved amendments to the Company's stock option plan to also provide for performance vesting of stock options. Shareholder ratification was obtained at the Annual and Special Meeting of Shareholders on April 19, 2007. Performance options granted may vest in one-third increments if the Company's annual total shareholder return (stock price appreciation and cumulative dividends on a reinvested basis) falls within certain percentile ranks relative to its industry peer group. The ultimate number of performance options exercisable will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared to its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared to its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking.

On April 19, 2007, the Company granted 25,211,082 options at a price of $41.66, including 15,126,650 performance options.

The following tables cover all stock options granted by the Company for the periods shown.

	Six months ended June 30			
	2007		2006	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of period	11,656	$ 16.40	14,570	$ 12.91
Granted	25,211	$ 41.66	1,134	$ 34.66
Exercised for common shares	(311)	$ 11.93	(124)	$ 10.49
Surrendered for cash	(3,712)	$ 13.32	(1,668)	$ 11.42
Forfeited	(639)	$ 38.79	(346)	$ 20.09
Outstanding at June 30	**32,205**	**$ 36.07**	13,566	$ 14.75
Options exercisable at June 30	**5,435**	**$ 12.43**	6,291	$ 11.80

	June 30, 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
$6.81 - $9.99	61	$ 7.21	1	61	$ 7.21
$10.00 - $10.99	62	$ 10.32	1	62	$ 10.32
$11.00 - $12.99	5,048	$ 11.74	2	5,048	$ 11.74
$13.00 - $19.99	312	$ 15.95	2	81	$ 14.87
$20.00 - $29.99	596	$ 25.87	3	49	$ 26.07
$30.00 - $39.99	1,307	$ 35.90	4	134	$ 35.13
$40.00 - $41.66	24,819	$ 41.66	5	-	$ -
	32,205	**$ 36.07**	**4**	**5,435**	**$ 12.43**

A downward adjustment of $0.175 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 $0.25 per share dividend that was declared in February 2007.

Note 10 Employee Future Benefits

Total benefit costs recognized were as follows:

	Three months ended June 30		Six months ended June 30	
	2007	2006	**2007**	2006
Employer current service cost	**$ 6**	$ 5	**$ 12**	$ 9
Interest cost	**3**	3	**5**	5
Expected return on plan assets	**(3)**	(2)	**(5)**	(3)
Amortization of net actuarial losses	**1**	-	**2**	-
	$ 7	$ 6	**$ 14**	$ 11

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

Natural Gas Contracts

At June 30, 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	39,903	$ 2
Physical sale contracts	(39,903)	$ 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 June 30, 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	$ 1

This contract has been recorded at fair value in other assets. During the first six months 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 June 30, 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	$ (70)
6.25% notes	U.S. $ 75	$ 90	June 15, 2012	5.65	$ (10)
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67	$ (6)
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61	$ (8)

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 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 six months of 2007, the impact of these contracts was a gain of $2 million (2006 - gain of $6 million).

Embedded Derivatives

The Company entered into a contract with a Norwegian-based company for drilling services offshore China. The contract currency is U.S. dollars, which is not the functional currency of either transacting party. As a result, this contract has been identified as containing an embedded derivative requiring bifurcation and separate accounting treatment at fair value. This embedded derivative has been recorded at fair value in other assets and the resulting unrealized gain has been recorded in other expenses in the consolidated statement of earnings for the period. In the first six months of 2007, the impact was an unrealized gain on embedded derivatives of $48.7 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 June 30, 2007, $60 million of accounts receivable had been sold under the program (December 31, 2006 - nil). In July 2007, a further $290 million of accounts receivable was sold.

Note 12 Subsequent Event

On May 2, 2007, the Company entered into an agreement, which subsequently closed on July 3, 2007, to acquire a refinery in Lima, Ohio from Valero Energy Corporation through the purchase of all of the issued and outstanding shares of Lima Refining Company effective July 1, 2007. The purchase price was U.S. $1.9 billion plus net working capital. An additional U.S. $540 million was paid for feedstock and product inventory. The Company is currently working on the allocation of the purchase price.

Husky Energy Inc. will host a conference call for analysts and investors on Thursday, July 19, 2007 at 4:15 p.m. Eastern time to discuss Husky's second 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 5229. The Postview will be available until Sunday, August 19, 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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