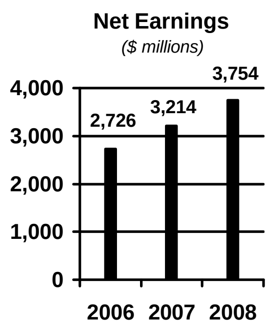
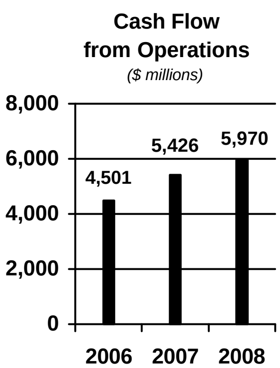
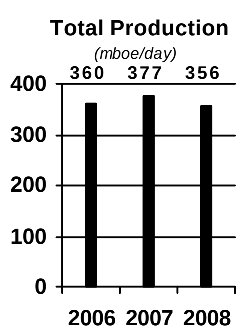
Quarterly Report to the Shareholders for the period ended December 31, 2008

HUSKY ENERGY REPORTS 2008 ANNUAL AND FOURTH QUARTER RESULTS







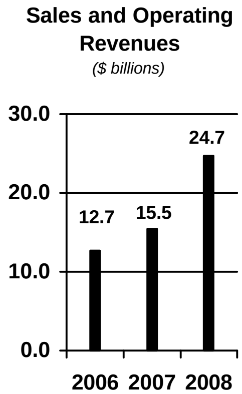
Calgary, Alberta (February 4, 2009) – Husky Energy Inc. (TSX - HSE) is pleased to announce 2008 net earnings of $3.8 billion or $4.42 per share (diluted), an increase of 17 percent from $3.2 billion or $3.79 per share (diluted) in 2007. Cash flow from operations increased to $6.0 billion or $7.03 per share (diluted) in 2008, a 10 percent increase compared with $5.4 billion or $6.39 per share (diluted) in 2007. Sales and operating revenues, net of royalties, were $24.7 billion for the year, an increase of 59 percent over the $15.5 billion in 2007.

"Husky's consistent focus on financial discipline, and project execution positioned the Company to perform well. Notwithstanding the impact of commodity prices and the deteriorating economic environment in the fourth quarter, Husky still posted a new record for earnings, cash flow and revenue," said John C.S. Lau, President & Chief Executive Officer of Husky Energy Inc. "2009 will be a challenging year for the industry. Husky has engineered steps to contain costs and optimize business operations."

2008 Highlights

In 2008 Husky achieved record financial performance and advanced a number of projects including:

- 114 million barrels of crude produced from White Rose by the end of 2008;
- commenced work on the North Amethyst satellite development offshore Newfoundland and Labrador;
- finalized a joint venture with BP in Sunrise Oil Sands development and crude oil processing at the Toledo Refinery in Ohio, U.S.;
- agreed with CNOOC (China National Offshore Oil Corporation) to jointly develop the Madura BD gas assets in Indonesia. Subsequently, the Madura BD Project Plan of Development was approved by the Indonesian Government;
- spudded the first appraisal well at Liwan in the South China Sea and advanced pre-FEED (Front-end engineering design) studies for Liwan development;
- expanded strategic positions in the exploration portfolio, including the acquisition of lands in the Columbia River Basin, in Washington and Oregon, U.S. and the acquisition of exploration blocks offshore Newfoundland and Labrador, Indonesia and China;
- Husky's 130 million litres per year Minnedosa, Manitoba, Ethanol Plant achieved full production;



- established an office in Columbus, Ohio, U.S. to market products from the Lima Refinery;
- since May 1996, the Husky Lloydminster Upgrader has operated 12.5 years achieving six million working hours without an employee lost time accident.

Production in 2008 was 355,900 barrels of oil equivalent per day, compared with 376,600 barrels of oil equivalent per day in 2007. Crude oil and natural gas liquids production was 256,800 barrels per day, compared with 272,700 barrels per day in 2007. This reflects the severe ice pack and iceberg winter conditions which delayed drilling and temporarily suspended production off the East Coast of Canada. Due to a weakening natural gas price and demand, gas production was reduced to 594 million cubic feet per day as compared with 623 million cubic feet per day in 2007.

In the White Rose satellite developments off Canada's East Coast, engineering and sub-sea system work progressed well. Results of the drilling of delineation wells at North Amethyst and West White Rose confirmed the Company's estimate of 210 million barrels of proved plus probable plus possible reserves (28 million barrels proved, 62 million barrels probable and 120 million barrels possible) in these two fields. Reserve estimates are as of December 31, 2008 and Husky has a 68.875 percent working interest. In December, the Mizzen exploration well (Husky 35 percent working interest) in the Flemish pass offshore Newfoundland commenced drilling.

Husky's oil sands projects are progressing. Pending a government and regulatory amendment approval, the partners in the Sunrise Oil Sands Project are expected to review project sanction by the end of 2009 and move to final approvals in the first half of 2010. The Sunrise Oil Sands Project is in an optimization phase to simplify the scope and to take advantage of the recent downturn in the demand for goods and services. Production at the Tucker Project ramped up to approximately 4,800 barrels per day at the year end and work continues on reservoir optimization. Additional drilling will most likely be delayed until market conditions improve.

Offshore China, the deep water drilling rig *West Hercules* began drilling the first appraisal well on its Liwan discovery in November 2008. Husky plans to drill three more delineation wells on the Liwan discovery as well as additional exploration wells on nearby prospects in 2009. The shallow water rig *Frontier Discoverer*, began drilling an exploration well in the South China Sea in January 2009. In Indonesia, Husky has contracted the drilling rig *Transocean Adriatic XI* to drill two shallow water exploration wells in the East Bawean II block.

Fourth Quarter Results

Financial performance in the fourth quarter was significantly affected by the economic environment and the decline in global commodity prices. These factors impacted the upstream business through lower realized prices and the U.S. downstream business through reductions in inventory values and lower refining crack spreads.

Husky's fourth quarter net earnings were $232 million or $0.27 per share (diluted), compared with $1.1 billion or $1.26 per share (diluted) in the same period of 2007. Adjusted Net Earnings in the fourth quarter amounted to $614 million or $0.72 per share (diluted), compared with $709 million or $0.84 per share (diluted) in the same quarter of 2007.

Cash flow from operations was $339 million or $0.40 per share (diluted) in the fourth quarter of 2008, compared with $1.4 billion or $1.68 per share (diluted) in the same period of 2007. Sales and operating revenues, net of royalties, were $4.7 billion in the fourth quarter of 2008, compared with $4.8 billion in the fourth quarter of 2007.

In the fourth quarter, total production averaged 358,400 barrels of oil equivalent per day, compared with 367,500 barrels of oil equivalent per day in the fourth quarter of 2007. Total crude oil and natural gas liquids production was 263,200 barrels per day, compared with 264,500 barrels per day in 2007. Natural gas production was 571 million cubic feet per day, compared with 618 million cubic feet per day in the same period of 2007. The decrease in natural gas production was mainly due to a strategic decision to reduce drilling in response to low natural gas prices.

Refining crack spread margins were very weak in the fourth quarter due to the economic downturn in the U.S. The main drivers of U.S. refining performance were 1) the 56 percent drop in crude oil price (WTI) which started the fourth quarter at U.S. $100.64 per barrel and fell 56 percent to U.S. $44.60 per barrel by year end, and 2) the delay between when crude is purchased and when refined products are produced and sold.

Financial Highlights 2008 versus 2007

- Earnings per share to $4.42 from $3.79
- Cash flow per share to $7.03 from $6.39
- Return on equity to 28.8% from 30.2%
- Return on average capital employed to 25.0% from 25.7%
- Debt to capital employed ratio to 12% from 19%
- Debt to cash flow ratio to 0.3 from 0.5

Husky has a solid balance sheet and is in a strong financial position. Total long-term debt including the current portion at December 31, 2008 was $1,957 million compared with $2,814 million at December 31, 2007. The total debt was partially offset by cash and cash equivalents of $913 million resulting in net debt of $1,044 million at December 31, 2008. Debt to cash flow from operations decreased to 0.3 times at the end of the year compared with 0.5 times at the 2007 year-end. The ratio of debt to capital employed improved to 12 percent at December 31, 2008 from 19 percent at December 31, 2007.

Table of Contents

1. Summary of Financial Results
2. Business Environment
3. Results of Operations
4. Liquidity and Capital Resources
5. Capability to Deliver Results and the Strategic Plan
6. Key Growth Highlights
7. Risk Management
8. Critical Accounting Estimates
9. Accounting Policies
10. Reader Advisories
11. Forward-Looking Statements and Information

Consolidated Financial Statements

1. Summary of Financial Results

- Record financial performance for 2008.
- Financial position remains strong, financing capital programs and retiring debt with cash generated from operating activities and cash on hand.
- Production in the fourth quarter on target compared with revised 2008 guidance.
- Average commodity price environment weakened significantly during the fourth quarter impacting all segments.
- Refined product margins were significantly lower than the previous year due to weak demand for products.
- Action taken to respond to the deteriorating economic environment including reduced capital spending, as per the December 2008 Guidance, implementation of cost containment and efficiency programs and managing access to credit markets to enhance liquidity.

Financial Summary

	Three months ended								Year ended	
	Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30	June 30	March 31	December 31	
(millions of dollars, except per share amounts and ratios)	**2008**	2008	2008	2008	2007	2007	2007	2007	**2008**	2007
Sales and operating revenues, net of royalties	**$ 4,701**	$ 7,715	$ 7,199	$ 5,086	$ 4,760	$ 4,351	$ 3,163	$ 3,244	**$24,701**	$15,518
Net earnings by sector										
Upstream	**$ 342**	$ 1,079	$ 1,239	$ 717	$ 864	$ 516	$ 636	$ 580	**$ 3,377**	$ 2,596
Midstream	**72**	100	153	144	218	129	77	111	**469**	535
Downstream	**(518)**	(9)	194	38	103	121	53	20	**(295)**	297
Corporate and eliminations	**336**	102	(223)	(12)	(111)	3	(45)	(61)	**203**	(214)
Net earnings	**$ 232**	$ 1,272	$ 1,363	$ 887	$ 1,074	$ 769	$ 721	$ 650	**$ 3,754**	$ 3,214
Per share - Basic and diluted	**$ 0.27**	$ 1.50	$ 1.61	$ 1.04	$ 1.26	$ 0.91	$ 0.85	$ 0.77	**$ 4.42**	$ 3.79
Cash flow from operations	**339**	2,000	2,090	1,541	1,425	1,420	1,257	1,324	**5,970**	5,426
Per share - Basic and diluted	**0.40**	2.36	2.46	1.82	1.68	1.67	1.48	1.56	**7.03**	6.39
Ordinary quarterly dividend per common share	**0.50**	0.50	0.40	0.33	0.33	0.25	0.25	0.25	**1.73**	1.08
Special dividend per common share	**-**	-	-	-	-	-	-	0.25	**-**	0.25
Total assets	**26,522**	26,292	25,296	24,391	21,697	20,718	17,969	17,781	**26,522**	21,697
Cash and cash equivalents	**913**	966	536	366	208	7	133	-	**913**	208
Total long-term debt including current portion	**1,957**	1,719	2,129	3,019	2,814	2,835	1,423	1,527	**1,957**	2,814
Return on equity [(1)] *(percent)*	**28.8**	36.6	34.9	31.2	30.2	26.6	27.1	32.1	**28.8**	30.2
Return on average capital employed [(1)] *(percent)*	**25.0**	31.6	30.9	26.5	25.7	22.3	23.8	27.3	**25.0**	25.7

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

2. Business Environment

Average Benchmarks

		Year ended		Three months ended					
				Dec. 31	Sept. 30	June 30	March 31	Dec. 31	Sept. 30
		2008	2007	**2008**	2008	2008	2008	2007	2007
WTI crude oil [1]	*(U.S. $/bbl)*	**99.65**	72.31	**58.73**	117.98	123.98	97.90	90.68	75.38
Brent crude oil [2]	*(U.S. $/bbl)*	**96.99**	72.52	**54.91**	114.78	121.38	96.90	88.70	74.87
Canadian light crude 0.3% sulphur	*($/bbl)*	**102.84**	77.07	**63.92**	122.53	126.73	98.20	87.19	80.70
Lloyd heavy crude oil @ Lloydminster	*($/bbl)*	**72.44**	40.75	**39.76**	96.17	89.70	64.23	42.03	43.61
NYMEX natural gas [1]	*(U.S. $/mmbtu)*	**9.04**	6.86	**6.94**	10.24	10.93	8.03	6.97	6.16
NIT natural gas	*($/GJ)*	**7.70**	6.26	**6.43**	8.76	8.86	6.76	5.69	5.31
WTI/Lloyd crude blend differential	*(U.S. $/bbl)*	**20.38**	23.81	**19.41**	18.34	21.95	21.81	34.06	23.50
Chicago 3:2:1 crack spread	*(U.S. $/bbl)*	**11.17**	17.68	**5.94**	17.31	13.61	7.82	9.15	18.58
New York Harbor 3:2:1 crack spread	*(U.S. $/bbl)*	**9.96**	14.15	**4.26**	10.96	14.50	10.09	8.23	11.91
U.S./Canadian dollar exchange rate	*(U.S. $)*	**0.937**	0.931	**0.825**	0.960	0.990	0.996	1.018	0.957

[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.*

Oil and Gas Prices

Our earnings are largely determined by realized prices for crude oil and natural gas including the U.S./Canadian dollar exchange rate. Significant fluctuations in our earnings are related to the volatility of oil and gas prices which are determined by market forces over which we have no control.

In 2008, the price of the main benchmark crude oil, West Texas Intermediate ("WTI"), initially declined in the first weeks of 2008, and then increased steadily through to the beginning of July 2008. High prices in the first half of the year began to result in lower demand in the United States toward mid year. In July 2008, global demand for energy began to collapse as a result of the global economic and financial crisis and prices fell through the fourth quarter and into January 2009. Production cuts announced by OPEC have not led to a measurable increase in oil prices. During 2008, the near-month contract price of WTI averaged U.S. $99.65/bbl and peaked above U.S. $145/bbl in mid July before declining to U.S. $44.60/bbl on December 31, 2008. The average in 2007 was U.S. $72.31/bbl. The average during the fourth quarter of 2008 was U.S. $58.73/bbl compared with U.S. $90.68/bbl in the fourth quarter of 2007.

A portion of Husky's crude oil production is classified as heavy crude oil, which trades at a discount to light crude oil. In 2008, 42% of Husky's crude oil production was heavy compared with 39% in 2007. The light/heavy crude oil differential averaged U.S. $20.38 or 20% of WTI in 2008 compared with U.S. $23.81 or 33% of WTI in 2007.

Natural gas prices quoted on the NYMEX rose sharply through the first seven months of 2008 based on lower storage levels and higher demand. After July 2008, natural gas prices fell steadily as natural gas storage levels increased. At the end of 2008, natural gas inventory in underground storage in the United States was 3% higher than the five year average and 1% higher than the previous year.

During 2008, the NYMEX near-month contract price of natural gas averaged U.S. $9.04/mmbtu and peaked above U.S. $13.50/mmbtu at the beginning of July before declining to U.S. $5.62/mmbtu on December 31, 2008. The average in 2007 was U.S. $6.86/bbl. The average during the fourth quarter of 2008 was U.S. $6.94/mmbtu and for the fourth quarter of 2007 was U.S. $6.97/mmbtu.

Foreign Exchange

The majority of the Company's revenues are received in U.S. dollars from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. Husky's results are affected by the exchange rate between the Canadian and U.S. dollar with a decrease in the value of the Canadian dollar relative to the U.S. dollar increasing the revenues received from the sale of oil and gas commodities offsetting the effect of lower oil and natural gas prices.

In 2008, the Canadian dollar averaged U.S. $0.937, 1% stronger than the previous year. The Canadian dollar weakened 14% against the U.S. dollar in the fourth quarter, closing at $0.817 U.S. per Canadian dollar at December 31, 2008.

Refining Crack Spreads

The 3:2:1 crack spread is the key indicator for refining margins as refinery gasoline output is approximately twice the distillate output. This crack spread is equal to the price of two-thirds of a barrel of gasoline plus one-third of a barrel of fuel oil (distillate) less one barrel of crude oil. Market crack spreads are based on NYMEX near-month contract averages and do not necessarily reflect the actual crude purchase costs or product configuration of a specific refinery.

During the fourth quarter of 2008, the New York Harbor 3:2:1 crack spread averaged U.S. $4.26/bbl compared with U.S. $8.23/bbl in the fourth quarter of 2007 and U.S. $ 10.96/bbl in the third quarter of 2008. During 2008, New York Harbor 3:2:1 crack spread averaged U.S. $9.96/bbl compared with U.S. $14.15/bbl in 2007.

During the fourth quarter of 2008, the Chicago crack spread averaged U.S. $5.94/bbl compared with U.S. $9.15/bbl in the fourth quarter of 2007 and U.S. $17.31/bbl in the third quarter of 2008. During 2008, the Chicago crack spread averaged U.S. $11.17/bbl compared with U.S. $17.68/bbl in 2007.

The lower 3:2:1 crack spreads were primarily due to low gasoline margins partially offset by higher distillate margins. Lower gasoline margins resulted primarily from high cost feedstock and ethanol blending coincident with decreasing demand for gasoline resulting from a faltering economy in the U.S. Distillate margins were higher throughout 2008 due to strong global demand. Realized refining margins are affected by the product configuration of each refinery and by the time lag between the purchase and delivery of crude oil which is accounted for on a first in first out basis in accordance with Canadian Generally Accepted Accounting Principles ("GAAP").

Cost Environment

The oil and gas industry has been experiencing an increase in costs in excess of the general rate of inflation. These increases affect the cost of operating the Company's oil and gas properties, processing plants and refineries. They also affect capital projects which are susceptible to cost volatility. The cost environment has not yet been impacted to the same extent as commodity prices by the current economic conditions.

Global Economic and Financial Crisis

The current global economic and financial crisis has reduced liquidity in financial markets, restricted access to financing and caused significant demand destruction for commodities and lower pricing. These have affected the economy in the latter half of 2008 and continue to impact the performance of the economy going forward. However, companies with low operating costs and flexible capital expenditure plans, strong cash generation from operations, availability of cash and cash equivalents, low debt with long maturities and unused committed credit facilities will be better positioned to manage through this crisis.

In view of the current economic environment, Husky has prudently reduced capital spending in 2009 and is reviewing and implementing cost containment and efficiency opportunities throughout the organization. We are managing our credit facilities and access to credit markets in order to enhance our liquidity in the coming year.

Sensitivity Analysis	2008 Fourth Quarter Average	Increase	Effect on Annual Pre-tax Cash Flow [7]		Effect on Annual Net Earnings [7]	
			($ millions)	*($/share)* [8]	*($ millions)*	*($/share)* [8]
Upstream and Midstream						
WTI benchmark crude oil price [1]	$ 58.73	*U.S. $1.00/bbl*	96	0.11	68	0.08
NYMEX benchmark natural gas price [2]	$ 6.94	*U.S. $0.20/mmbtu*	28	0.03	20	0.02
WTI/Lloyd crude blend differential [3]	$ 19.41	*U.S. $1.00/bbl*	(16)	(0.02)	(12)	(0.01)
Downstream						
Canadian light oil margins	$ 0.004	*Cdn $0.005/litre*	14	0.02	10	0.01
Asphalt margins	$ 22.34	*Cdn $1.00/bbl*	8	0.01	6	0.01
New York Harbor 3:2:1 crack spread [4]	$ 4.26	*U.S. $1.00/bbl*	88	0.10	55	0.07
Consolidated						
Exchange rate (U.S. $ per Cdn $) [1] [5]	$ 0.825	*U.S. $0.01*	(55)	(0.06)	(43)	(0.05)
Interest rate [6]		*100 basis points*	-	-	-	-

(1) Does not include gains or losses on inventory.
(2) Includes decrease in net earnings related to natural gas consumption.
(3) Excludes impact on asphalt operations.
(4) Relates to U.S. Refining & Marketing.
(5) Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.
(6) An interest rate change would not have an impact as Husky did not have variable rate debt outstanding as of December 31, 2008.
(7) Excludes derivatives.
(8) Based on 849.4 million common shares outstanding as of December 31, 2008.

3. Results of Operations

3.1 Upstream

Upstream Net Earnings Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2008**	2007	**2008**	2007
Gross revenues	**$ 1,566**	$ 1,893	**$ 9,932**	$ 7,287
Royalties	**271**	325	**2,043**	1,065
Net revenues	**1,295**	1,568	**7,889**	6,222
Operating and administration expenses	**396**	371	**1,596**	1,409
Depletion, depreciation and amortization	**394**	396	**1,505**	1,615
Other	**59**	(13)	**31**	(101)
Income taxes	**104**	(50)	**1,380**	703
Net earnings	**$ 342**	$ 864	**$ 3,377**	$ 2,596

Fourth Quarter

Upstream earnings in the fourth quarter of 2008 decreased by $522 million compared with the fourth quarter of 2007, which included an income tax recovery of $304 million which was the result of a change in the corporate income tax rates announced in December, 2007. The remaining reduction in earnings is mainly as a result of declining crude oil prices partially offset by higher natural gas prices. Production of crude oil and natural gas declined 2% compared with the same period in 2007.

During the fourth quarter of 2008, our realized heavy crude oil and bitumen prices averaged 66% of our realized light crude oil and NGL prices versus 49% during the same period in 2007.

Income tax recoveries in 2007 reflect a change in the statutory tax rate announced in December 2007.

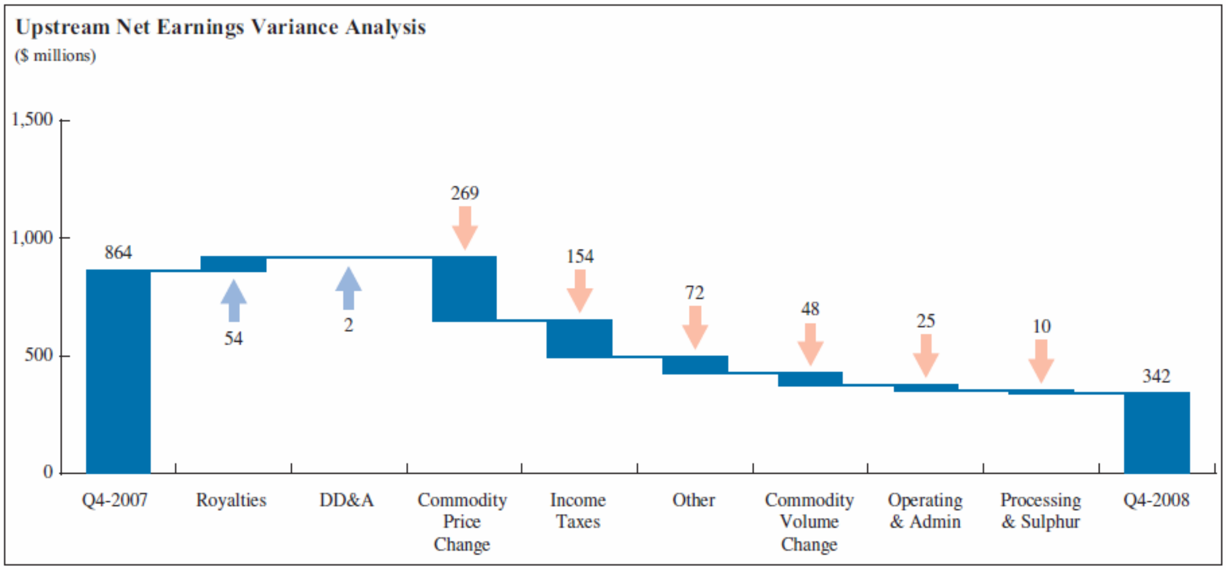
Twelve Months

Upstream earnings were $781 million higher in 2008 than in 2007 as a result of higher crude oil and natural gas prices which more than offset lower production and the income tax reductions booked in the fourth quarter of 2007.

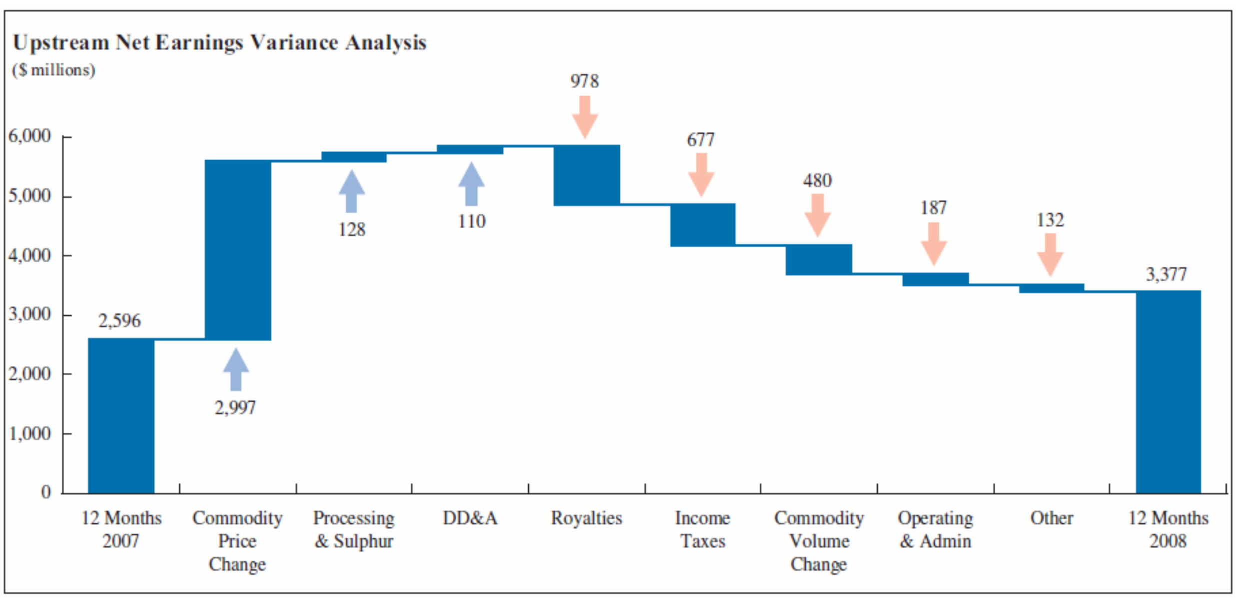
Our realized heavy crude oil and bitumen prices averaged 74% of our realized light crude oil and NGL prices versus 55% in 2007.

Upstream Net Earnings Variance Analysis

Fourth Quarter



Twelve Months



Pricing

Average Sales Prices Realized		Three months ended Dec. 31		Year ended Dec. 31	
		2008	2007	**2008**	2007
Crude Oil	*($/bbl)*				
Light crude oil & NGL		**$ 58.43**	$ 83.43	**$ 97.28**	$ 73.54
Medium crude oil		**47.02**	55.37	**81.79**	51.12
Heavy crude oil & bitumen		**38.83**	41.13	**71.61**	40.19
Total average		**49.02**	63.34	**84.96**	58.24
Natural Gas	*($/mcf)*				
Average		**6.84**	5.72	**7.94**	6.19

Oil and Gas Production

Daily Gross Production		Three months ended Dec. 31		Year ended Dec. 31	
		2008	2007	**2008**	2007
Crude oil & NGL	*(mbbls/day)*				
Western Canada					
Light crude oil & NGL		**24.7**	25.8	**24.6**	26.5
Medium crude oil		**26.6**	27.0	**26.9**	27.1
Heavy crude oil & bitumen		**110.7**	107.8	**107.0**	106.9
		162.0	160.6	**158.5**	160.5
East Coast Canada					
White Rose - light crude oil		**77.2**	81.1	**73.2**	85.0
Terra Nova - light crude oil		**11.5**	11.6	**12.9**	14.5
China					
Wenchang - light crude oil & NGL		**12.5**	11.2	**12.2**	12.7
Total crude oil & NGL		**263.2**	264.5	**256.8**	272.7
Natural gas	*(mmcf/day)*	**571.1**	617.8	**594.4**	623.3
Total	*(mboe/day)*	**358.4**	367.5	**355.9**	376.6

Crude Oil and NGL Production

Fourth Quarter

In the fourth quarter of 2008, crude oil and NGL production decreased by less than 1% compared with the same period in 2007. On the East Coast, light oil production was lower due to subsea operational issues at White Rose which resulted in the loss of approximately 7 mboe/day from October 31, 2008. This was partially offset by production from the eighth producing well which commenced on September 21, 2008 and contributed approximately 6 mboe/day for the quarter. Heavy oil and bitumen production increased as a result of improved production at the Tucker oil sands project.

Twelve Months

In 2008, crude oil and NGL production decreased by 6% compared with the previous year. Production from the White Rose field was shut down for 11 days in April due to the encroachment of severe ice pack and iceberg conditions, which also delayed the drilling of the eighth producing well, and for 4 days in the third quarter due to offloading operational restrictions combined with tanker availability. White Rose was shut down for 16 days for scheduled maintenance in the third quarter of 2007. In June 2008, Terra Nova was shut down for 14 days for a scheduled maintenance turnaround and in the third and fourth quarters operational and maintenance issues also resulted in reduced production.

During 2008, crude oil and NGL production from Western Canada was down 1% compared with 2007 primarily due to reservoir decline, development delays and shut-in facilities.

Natural Gas Production

Fourth Quarter

Production of natural gas decreased by 8% compared with the same period of the previous year. In the fourth quarter of 2007 we drilled 20 net natural gas exploration wells and 56 net development wells compared with 42 net exploration and 159 net development wells in the fourth quarter of 2006. These wells support production in the following year. This reduction in drilling contributed to a drop in natural gas production in 2008 in all quarters. In addition, pipeline capacity was lower in the fourth quarter of 2008 as a result of unplanned repairs and maintenance combined with unscheduled plant outages.

In the fourth quarter of 2008, 64% of our natural gas production was from the foothills of Alberta and British Columbia, the deep basin of Alberta and the plains of northeast British Columbia and northwest Alberta; the remainder was from the plains throughout Alberta and southwest Saskatchewan.

Twelve Months

In addition to the factors affecting the fourth quarter, natural gas production was 5% lower in 2008 compared with 2007 due to severe cold weather in Western Canada in the first quarter of 2008.

Royalties

In the fourth quarter of 2008, royalty rates in Western Canada averaged 14% as a percentage of gross revenue, down from 17% in the fourth quarter of 2007.

In March 2008, the Tier II incremental royalty rate became effective for White Rose and Terra Nova. As a result, East Coast offshore royalty rates averaged 25% as a percentage of gross revenue in the fourth quarter compared with 17% in the fourth quarter of 2007.

Royalty rates for 2008 averaged 16% in Western Canada and 28% offshore the East Coast compared with 16% and 13% respectively in 2007.

Unit Operating Costs

Fourth Quarter

In the fourth quarter of 2008, total upstream operating costs averaged $10.84/boe compared with $9.61/boe in the same period in 2007. Operating costs in Western Canada averaged $13.28/boe compared with $11.85/boe in the same period in 2007. Increasing operating costs in Western Canada are generally related to the nature of exploitation necessary to manage production from maturing fields and new more extensive but less prolific reservoirs. Western Canada operations require increasing amounts of infrastructure including more wells, facilities associated with enhanced recovery schemes, more extensive pipeline systems, crude and water trucking and more complex natural gas compression systems. These factors in turn require higher energy consumption, workovers and generally more material costs. We are focused on managing rising operating costs through cost reduction and efficiency initiatives and keeping our infrastructure, including gas plants, crude processing plants, transportation systems, compression systems, lease access and other infrastructure fully utilized.

Operating costs at the East Coast offshore operations averaged $4.32/bbl in the fourth quarter compared with $3.91/bbl in the same period in 2007. Total operating costs were comparable with the unit increase attributable to lower production. Operating costs at the South China Sea offshore operations averaged $5.54/bbl in the fourth quarter of 2008 compared with $4.25/bbl in the same period in 2007, as a result of higher maintenance activity in the quarter to support production for the maturing field.

Twelve Months

Total upstream unit operating costs in 2008 averaged $10.93/boe compared with $9.09/boe in 2007. In addition to the factors affecting the fourth quarter, operating costs were adversely affected in the first quarter by extreme cold weather in Western Canada, which resulted in increased costs for gas well servicing and methanol injection to deal with gas well freeze ups. In the second quarter operating costs increased compared with the previous year due to additional resources required to manage ice encroachment and subsurface mechanical issues on the East Coast. Energy costs increased throughout the year with increased natural gas prices.

Unit Depletion, Depreciation and Amortization

Fourth Quarter

Total unit DD&A averaged $11.95/boe in the fourth quarter of 2008 compared with $11.71/boe in the fourth quarter of 2007. In Canada, unit DD&A was $11.92/boe, an increase of 1% from the fourth quarter of 2007. The higher DD&A rate in Canada was primarily due to lower oil and gas reserves, which was partially offset by the disposition of 50% of the Sunrise oil sands asset, which reduced the full cost base by approximately $1.6 billion or $1.62/boe in the fourth quarter of 2008. The Sunrise Oil Sands Project currently does not have any proved reserves attributed to it.

Twelve Months

In 2008, total unit DD&A averaged $11.56/boe compared with $11.75/boe in 2007. This was primarily due to the effect of the Sunrise disposition partially offset by a higher full cost base and lower oil and gas reserves in 2008 compared with 2007. The increase in the full cost base is primarily for drilling and infrastructure required to maintain production in Western Canada.

Netback Analysis	Three months ended Dec. 31		Year ended Dec. 31	
	2008	2007	**2008**	2007
	$	**$**	**$**	**$**
Total				
Crude oil equivalent *(per boe)* [(1)]				
Gross price	**46.89**	55.20	**74.57**	52.41
Royalties	**8.74**	9.58	**15.52**	7.74
Net sales price	**38.15**	45.62	**59.05**	44.67
Operating costs [(2)]	**10.84**	9.61	**10.93**	9.09
Operating netback	**27.31**	36.01	**48.12**	35.58
DD&A	**11.95**	11.71	**11.56**	11.75
Administration expenses and other [(2)]	**1.85**	0.22	**0.05**	(0.17)
Earnings before income taxes	**13.51**	24.08	**36.51**	24.00
Western Canada				
Crude oil *(per boe)* [(1)]				
Light crude oil				
Gross price	**55.87**	66.38	**82.97**	61.02
Royalties	**8.05**	11.94	**11.53**	7.87
Net sales price	**47.82**	54.44	**71.44**	53.15
Operating costs [(2)]	**16.28**	15.04	**13.90**	13.24
Operating netback	**31.54**	39.40	**57.54**	39.91
Medium crude oil				
Gross price	**46.59**	54.25	**79.91**	50.42
Royalties	**6.70**	9.78	**13.91**	8.89
Net sales price	**39.89**	44.47	**66.00**	41.53
Operating costs [(2)]	**15.94**	14.48	**15.60**	13.92
Operating netback	**23.95**	29.99	**50.40**	27.61
Heavy crude oil & bitumen				
Gross price	**38.75**	41.02	**71.19**	40.14
Royalties	**5.53**	5.83	**10.52**	5.26
Net sales price	**33.22**	35.19	**60.67**	34.88
Operating costs [(2)]	**15.13**	13.63	**15.60**	12.81
Operating netback	**18.09**	21.56	**45.07**	22.07
Natural gas *(per mcfge)* [(3)]				
Gross price	**6.77**	6.17	**8.21**	6.42
Royalties	**1.24**	1.16	**1.60**	1.23
Net sales price	**5.53**	5.01	**6.61**	5.19
Operating costs [(2)]	**1.59**	1.41	**1.59**	1.39
Operating netback	**3.94**	3.60	**5.02**	3.80
East Coast				
Light crude oil *(per boe)* [(1)]				
Gross price	**61.15**	85.31	**100.12**	75.37
Royalties [(4)]	**15.18**	14.46	**28.45**	9.43
Net sales price	**45.97**	70.85	**71.67**	65.94
Operating costs [(2)]	**4.32**	3.91	**4.99**	4.07
Operating netback	**41.65**	66.94	**66.68**	61.87
International				
Light crude oil *(per boe)* [(1)]				
Gross price	**50.47**	89.17	**98.70**	77.07
Royalties	**7.71**	24.14	**27.46**	15.50
Net sales price	**42.76**	65.03	**71.24**	61.57
Operating costs [(2)]	**5.54**	4.25	**4.86**	3.84
Operating netback	**37.22**	60.78	**66.38**	57.73

(1) *Includes associated co-products converted to boe.*
(2) *Operating costs exclude accretion, which is included in administration expenses and other.*
(3) *Includes associated co-products converted to mcfge.*
(4) *During March 2008, White Rose royalties achieved payout status for Tier 2 royalties.*

Other Items

During the fourth quarter of 2008, a drilling contract previously treated as an embedded derivative no longer met the criteria and the related accounting treatment was discontinued. A loss of $42 million, after tax, was recorded in the fourth quarter compared with a gain of $9 million, after tax, in the fourth quarter of 2007. A loss of $71 million, after tax, was recorded in 2008 compared with a gain of $71 million, after tax, for the same period in 2007.

During the second quarter of 2008, a gain of $69 million was recorded on the sale of 50% of the shares of Husky Oil (Madura) Limited to CNOOC Southeast Asia Limited.

Upstream Capital Expenditures

At December 31, 2008, our overall upstream capital expenditures were $3.6 billion, including acquisitions. Our major upstream projects on the East Coast of Canada and offshore China and Indonesia remain essentially on schedule.

Capital Expenditures Summary [1]	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2008**	2007	**2008**	2007
Exploration				
Western Canada	**$ 204**	$ 118	**$ 680**	$ 456
East Coast Canada and Frontier	**66**	51	**160**	84
Northwest United States	**10**	-	**60**	-
International	**110**	24	**225**	70
	390	193	**1,125**	610
Development				
Western Canada	**611**	476	**1,881**	1,575
East Coast Canada	**171**	36	**569**	197
International	**2**	1	**5**	6
	784	513	**2,455**	1,778
	$ 1,174	$ 706	**$ 3,580**	$ 2,388

[1] *Excludes capitalized costs related to asset retirement obligations incurred during the period and the Lima acquisition and the BP joint venture transaction.*

In the year 2008, capital expenditures were $2.6 billion (72%) in Western Canada, $729 million (20%) off the East Coast of Canada, $60 million (2%) in the Northwest United States and $230 million (6%) offshore China and Indonesia.

The following table discloses the number of gross and net exploration and development wells we completed in Western Canada and the oil sands during the periods indicated. Ninety-six percent of the net exploration wells and 93% of the net development wells drilled in the fourth quarter of 2008 resulted in wells capable of commercial production as compared with 100% and 95% respectively in the same period of 2007.

Western Canada and Oil Sands Wells Drilled		Three months ended Dec. 31				Year ended Dec. 31			
		2008		2007		**2008**		2007	
		Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Exploration	Oil	**42**	**34**	23	23	**80**	**70**	79	79
	Gas	**21**	**15**	29	20	**102**	**79**	114	92
	Dry	**4**	**2**	1	-	**27**	**23**	14	12
		67	**51**	53	43	**209**	**172**	207	183
Development	Oil	**230**	**190**	154	143	**685**	**578**	571	530
	Gas	**143**	**78**	102	56	**435**	**270**	343	251
	Dry	**20**	**20**	12	10	**36**	**36**	31	29
		393	**288**	268	209	**1,156**	**884**	945	810
Total		**460**	**339**	321	252	**1,365**	**1,056**	1,152	993

Western Canada - Excluding Oil Sands

During 2008, we invested $2.2 billion on exploration and development throughout the Western Canadian Sedimentary Basin excluding oil sands. Of this, $678 million was invested on oil development and $360 million was invested on natural gas development. We drilled 1,056 net wells in the basin resulting in 648 net oil wells and 349 net natural gas wells. In addition, $211 million was spent on production optimization and operating cost reduction initiatives. Capital spending on facilities, land acquisition and retention and environmental protection amounted to $291 million. During 2008, $308 million was spent on property acquisitions.

Our high impact exploration program is conducted along the foothills of Alberta and British Columbia and in the deep basin region of Alberta. In 2008, we invested $362 million on drilling in these natural gas prone areas. During this period we drilled 25 net exploration wells in the foothills and deep basin regions; 21 net wells were cased as natural gas wells and one was cased as a net oil well. The remaining 147 net exploration wells were drilled primarily in the shallow regions of the Western Canadian Sedimentary Basin.

Oil Sands

Oil sands capital expenditures totalled $302 million during 2008. At Tucker, we spent $90 million on completion of new well pairs, facility modification and new pad preparation. At Sunrise, we spent $143 million on engineering design, site preparation and facilities and equipment requisitions. At Caribou and Saleski we spent $69 million on stratigraphic drilling and engineering and geophysical studies.

East Coast Development

During 2008, we spent $569 million on East Coast development projects primarily for the North Amethyst and West White Rose tie-back development projects and the completion of an infill production well and other capital enhancements at White Rose. Construction commenced on North Amethyst and long lead equipment was procured. Engineering design began at the West White Rose development and a production well and water injection well were drilled at the White Rose South Avalon field.

East Coast and Northwest Territories Exploration

During 2008, we spent $160 million on two exploration wells in the Central Mackenzie Valley and on our East Coast seismic program.

Northwest United States

On September 30, 2008, we spent $50 million to acquire petroleum and natural gas rights in the Columbia River Basin located in southeastern Washington and northeast Oregon and a 50% interest in an exploration well currently being drilled.

Offshore China and Indonesia

During 2008, we spent $225 million on exploration drilling in the South China Sea and seismic data acquisition on the East Bawean II exploration block in the Java Sea, Indonesia.

Oil and Gas Reserves

Reconciliation of Proved Reserves (1)

	Crude oil & NGL *(mmbbls)*	Natural gas *(bcf)*	Equivalent units *(mmboe)*
December 31, 2007	649	2,191	1,014
Revision of previous estimates	(76)	(42)	(84)
Discoveries, extensions and improved recovery	44	182	75
Purchase of reserves in place	9	96	25
Sale of reserves in place	(1)	(19)	(4)
Production	(94)	(218)	(130)
December 31, 2008	**531**	**2,190**	**896**
Proved plus probable reserves			
December 31, 2008	**834**	**2,906**	**1,319**
December 31, 2007	2,688	3,180	3,218

(1) *Constant price before royalties.*

Husky's proved oil and gas reserves at December 31, 2008 were 896 million boe, down 118 mmboe or 12% from the previous year. Oil and gas reserves decreased in 2008 primarily as a result of a negative revision related to lower oil and gas prices at December 31, 2008.

Husky's oil and gas reserves are estimated in accordance with the regulation and guidelines of the U.S. Securities and Exchange Commission ("SEC"), which requires reserves to be based on oil and gas prices in effect on the day that the reserves are evaluated. On December 31, 2008, West Texas Intermediate was U.S. $44.60/bbl and Lloydminster heavy crude oil, which trades at a discount to light crude oil, was $34.56/bbl. At this price some heavy oil reserves, particularly those that require future development capital, became uneconomic and were removed from reserves until market conditions improve.

The 2008 negative price revision to proved oil and gas reserves amounted to 98 mmboe, 69 mmboe or 70% of it related to lower bitumen prices and the remaining 29 mmboe was due to lower heavy and medium oil and natural gas prices. This price related revision did not result in any impairments of property, plant and equipment. This was offset by net positive technical revisions of 14 mmboe.

Husky's probable oil and gas reserves decreased by 1,781 mmboe in 2008. The 2008 negative price revision to probable oil and gas reserves amounted to 1,042 mmboe; 1,016 mmboe or 98% was related to lower bitumen prices. Probable reserves were also reduced by divestitures of 50% of the Sunrise Oil Sands Project and 50% of the Madura natural gas and natural gas liquids development in Indonesia, which in aggregate was 886 mmboe.

On December 29, 2008, the SEC announced that it had approved revisions to modernize its oil and gas reporting requirements to help investors evaluate their investments in oil and gas companies. The new rules will be effective for fiscal years ending on or after December 31, 2009. The new rules provide for, among other things, disclosure of oil and gas reserves evaluated using annual average prices based on the prices in effect on the first day of each month.

Had these rules been in effect at December 31, 2008, Husky's oil and gas reserves based on the average monthly 2008 WTI price of U.S. $101.87/bbl and the Lloydminster heavy crude oil price of $60.90/bbl would have been reported as follows:

Proved Reserves In Accordance with pending SEC Rules effective 2009	Crude oil & NGL *(mmbbls)*	Natural gas *(bcf)*	Equivalent units *(mmboe)*
December 31, 2008	531	2,190	896
Price revision	92	32	98
December 31, 2008	623	2,222	994
Proved plus probable reserves			
December 31, 2008	834	2,906	1,319
Price revision	1,131	56	1,140
December 31, 2008	1,965	2,962	2,459

3.2 Midstream

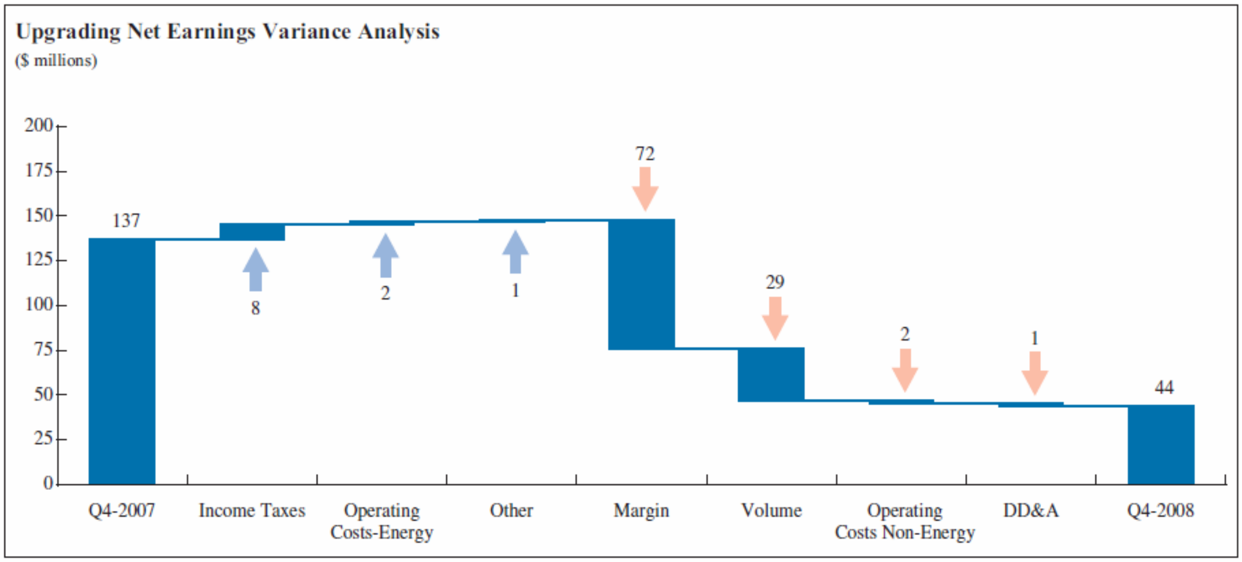
Upgrading Net Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		**2008**	2007	**2008**	2007
Gross margin		**$ 131**	$ 232	**$ 633**	$ 614
Operating and administration expenses		**61**	61	**256**	221
Other recoveries		**(2)**	(1)	**(4)**	(4)
Depreciation and amortization		**9**	8	**31**	25
Income taxes		**19**	27	**105**	90
Net earnings		**$ 44**	$ 137	**$ 245**	$ 282
Selected operating data:					
Upgrader throughput [(1)]	*(mbbls/day)*	**70.8**	73.1	**68.1**	61.4
Synthetic crude oil sales	*(mbbls/day)*	**58.2**	66.5	**58.7**	53.1
Upgrading differential	*($/bbl)*	**$ 27.48**	$ 36.74	**$ 28.77**	$ 30.73
Unit margin	*($/bbl)*	**$ 24.60**	$ 37.92	**$ 29.48**	$ 31.67
Unit operating cost [(2)]	*($/bbl)*	**$ 9.54**	$ 8.95	**$ 10.30**	$ 9.83

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

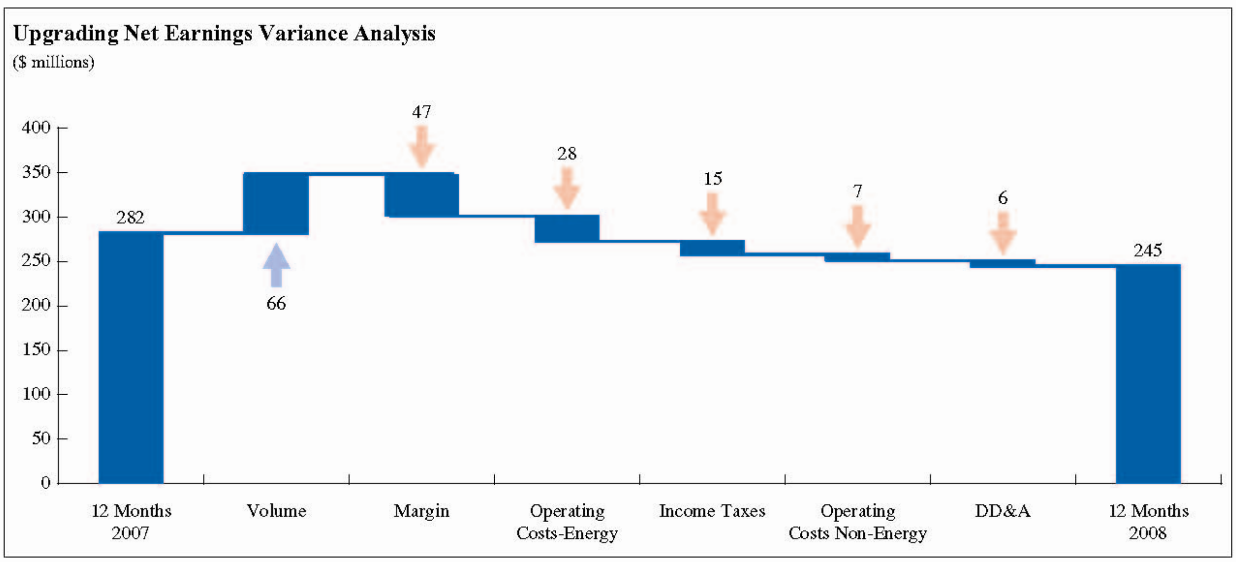
The upgrading business segment adds value by processing heavy sour crude oil into high value synthetic crude oil and low sulphur distillates. The upgrader profitability is primarily dependent on the differential between the cost of heavy crude feedstock and the sales price of synthetic crude oil.

Upgrading Net Earnings Variance Analysis

Fourth Quarter



Twelve Months



Fourth Quarter

During the fourth quarter of 2008, the upgrading differential averaged $27.48/bbl, a decrease of $9.26/bbl compared with the same period in 2007. The differential is equal to the price of Husky Synthetic Blend, which sells at a premium to West Texas Intermediate, less the price of Lloyd Heavy Blend. During the fourth quarter of 2008, the overall unit margin was 35% lower than the previous year mainly due to the narrowing light to heavy oil differentials. Synthetic crude sales volumes declined due to lower production. Upgrader throughput was 3% lower in the fourth quarter of 2008 compared with the same period in 2007. In 2007, the upgrader was operating one hydrocracker train at lower rates due to maintenance requirements and in the fourth quarter of 2008 one hydrogen exchanger was shut down for 10 days for unplanned maintenance.

In the fourth quarter of 2007, upgrader earnings include an income tax recovery of $24 million which was the result of a change in the corporate income tax rates announced in December, 2007.

Unit operating costs increased due to lower production in the fourth quarter of 2008 compared with 2007.

Twelve Months

In 2008, upgrading earnings were 13% lower than 2007. Upgrader throughput was 11% higher compared with the same period in 2007. In 2007, throughput was lower due to a 49-day scheduled turnaround and installation of new coke drums during the second quarter. In 2008 the upgrader was shut down for 34 days for a scheduled turnaround and throughput was also impacted during 2008 due to a temporary shutdown to replace the hydrogen plant catalyst during the second quarter. However the higher throughput in 2008 was offset by declining differentials compared with 2007.

Operating costs have increased in 2008 due to higher steam, gas, and electricity volumes and prices, offset by lower contract labor.

Infrastructure and Marketing Net Earnings Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)	**2008**	2007	**2008**	2007
Gross margin - pipeline	**$ 19**	$ 28	**$ 120**	$ 115
- other infrastructure and marketing	**36**	87	**249**	278
	55	115	**369**	393
Operating and administration expenses	**7**	7	**17**	14
Depreciation and amortization	**8**	7	**31**	28
Income taxes	**12**	20	**97**	98
Net earnings	**$ 28**	$ 81	**$ 224**	$ 253
Selected operating data:				
Aggregate pipeline throughput *(mbbls/day)*	**493**	497	**507**	501

Fourth Quarter

Infrastructure and marketing net earnings in the fourth quarter of 2008 were 65% lower than the same period in 2007. Lower earnings were primarily due to significantly lower margins on crude oil and natural gas trading contracts, as commodity prices decreased throughout the quarter, partially offset by unrealized gains on natural gas storage contracts.

In the fourth quarter of 2007, infrastructure and marketing earnings include an income tax recovery of $12 million which was the result of a change in the corporate income tax rates announced in December, 2007.

Twelve Months

In 2008, infrastructure and marketing earnings were 11% lower than the previous year primarily due to higher margins on crude oil and sulphur trading contracts during the first half of 2008 offset by declining margins in the latter half of the year.

Midstream Capital Expenditures

Midstream capital expenditures totalled $193 million in 2008. At the Lloydminster upgrader we spent $99 million, primarily for contingent consideration and facility reliability projects. The remaining $94 million was spent on the pipeline extension between Lloydminster and Hardisty, Alberta, tankage upgrades at Hardisty and capital enhancements of the cogeneration plants.

3.3 Downstream

Canadian Refined Products Net Earnings Summary		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)		**2008**	2007	**2008**	2007
Gross margin - fuel sales		**$ 4**	$ 44	**$ 122**	$ 188
- ancillary sales		**9**	11	**42**	42
- asphalt sales		**46**	29	**130**	160
		59	84	**294**	390
Operating and administration expenses		**22**	25	**67**	82
Depreciation and amortization		**20**	19	**81**	66
Income taxes		**1**	(12)	**40**	50
Net earnings		**$ 16**	$ 52	**$ 106**	$ 192
Selected operating data:					
Number of fuel outlets				**492**	505
Light oil sales	*(million litres/day)*	**7.5**	8.5	**7.9**	8.7
Light oil retail sales per outlet	*(thousand litres/day)*	**12.7**	13.4	**13.0**	13.2
Prince George refinery throughput	*(mbbls/day)*	**10.7**	11.6	**10.1**	10.5
Asphalt sales	*(mbbls/day)*	**21.4**	24.5	**24.0**	21.8
Lloydminster refinery throughput	*(mbbls/day)*	**28.8**	28.8	**26.1**	25.3
Ethanol production	*(thousand litres/day)*	**661.3**	347.2	**627.2**	324.6

Canadian Refined Products

Fourth Quarter

Gross margin on fuel sales was lower in the fourth quarter of 2008 compared with 2007 due to lower average retail margins and lower sales volumes due to weak demand. Asphalt margins increased 59% in the fourth quarter of 2008 compared with 2007 due to rapidly declining crude oil feedstock costs. Fourth quarter 2008 ethanol production increased 90% due to the start-up of the Minnedosa ethanol plant, which commenced operations at the end of 2007.

In the fourth quarter of 2007, Canadian refined products earnings include an income tax recovery of $24 million which was the result of a change in the corporate income tax rates announced in December, 2007.

Twelve Months

Fuel sales margins in 2008 were impacted by the same factors impacting the fourth quarter and by lower volumes due to shortages in the third quarter from third party suppliers as a result of refinery outages. Margins on asphalt products were lower than those of the previous year due to rising crude oil feedstock costs to the end of the third quarter partially offset by declining crude oil feedstock costs in the fourth quarter. Ethanol production increased 93% over 2007 due to the startup of the new Minnedosa Ethanol Plant, which commenced operations at the end of 2007; however earnings from total ethanol sales for both plants were lower than 2007 due to much lower sales values, higher feedstock costs, and natural gas costs.

U.S. Refining and Marketing Net Earnings Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except where indicated)	**2008**	2007	**2008**	2007
Gross refining margin	**$ (648)**	$ 155	**$ (58)**	$ 310
Processing costs	**145**	48	**414**	93
Operating and administration expenses (recoveries)	**(4)**	1	**3**	1
Interest - net	**1**	-	**3**	1
Depreciation and amortization	**50**	25	**154**	47
Income taxes	**(306)**	30	**(231)**	63
Net earnings (loss)	**$ (534)**	$ 51	**$ (401)**	$ 105
Selected operating data:				
Lima Refinery throughput *(mbbls/day)*	**127.6**	147.7	**136.6**	143.8 [(2)]
Toledo Refinery throughput *(mbbls/day)*	**61.9**	-	**60.6 [(1)]**	-
Refinery inventory *(feedstocks and refined products)* *(mmbbls)*	**11.9**	7.4	**11.9**	7.4

(1) *The Toledo Refinery operating results are included from March 31, 2008, the date the acquisition was completed. Throughput represents nine months of operations.*
(2) *The Lima Refinery operating results are included from July 1, 2007, the date the acquisition was completed. Throughput represents six months of operations.*

U.S. Refining and Marketing

The U.S. Refining and Marketing segment commenced operations on July 1, 2007 with the acquisition of the Lima, Ohio refinery.

On March 31, 2008, we completed a transaction that resulted in the formation of two joint venture entities forming an integrated oil sands business and a refining joint venture. We hold a 50% interest in the BP-Husky Toledo Refinery.

Fourth Quarter

Pricing for refinery output at the Lima and Toledo refineries is impacted by the New York Harbor 3:2:1 refining crack spread and the Chicago 3:2:1 refining crack spread. In the fourth quarter of 2008, average refining crack spreads at Chicago dropped to U.S. $5.94/bbl, a 35% decline compared with the same period in 2007 and a 66% decline compared with the third quarter of 2008. In the fourth quarter of 2008, average New York Harbor 3:2:1 refining crack spreads dropped to U.S. $4.26/bbl, a 48% decline compared with the same period in 2007 and a 61% decline compared with the third quarter of 2008. Chicago 3:2:1 crack spreads reached a low of negative U.S. $1.83/bbl during the fourth quarter and New York Harbor 3:2:1 refining crack spreads were as low as U.S. $2.00/bbl.

The market refining crack spread is based on crude feedstock accounted for on a last in first out basis ("LIFO"). However our financial statements are based on first in first out ("FIFO") inventory accounting which is in accordance with Canadian GAAP. In a stable commodity price environment FIFO and LIFO accounting should not result in significant differences between market benchmarks and individual refinery results. In a rapidly declining commodity price environment, the result is that the cost of crude feedstock consumed in the fourth quarter is higher under FIFO than on a LIFO basis as it was acquired in a significantly higher commodity price environment as a result of the time lag between crude feedstock purchase and processing through the refinery.

In the same period, demand for refined products continued to decline as a result of the deteriorating economic environment resulting in rapidly declining prices for finished products, particularly gasoline. In addition, the Chicago and New York Harbor 3:2:1 refining crack spreads are based on a product mix that includes only gasoline and distillate. The output of the Lima and Toledo refineries is approximately 12% other refined products which typically sell for lower prices than gasoline or distillate. The combination of these factors resulted in gross refining margin losses of $648 million in the fourth quarter.

The rapid decline in the value of the Canadian dollar versus the U.S. dollar further exacerbated the impact of the refinery losses in Canadian dollars.

Processing costs in the fourth quarter of 2008 include both refineries compared with the same period in 2007 which did not include the Toledo refinery. Operating costs have increased due to turnaround activity and higher energy costs at Toledo and higher energy and maintenance costs at Lima.

Twelve Months

In 2008, earnings from the U.S. Refining and Marketing segment reflect a full twelve months of operations from the Lima Refinery and nine months of operations from the Toledo Refinery from March 31, 2008.

In addition to the factors affecting the fourth quarter, the drop in demand for motor fuels that began in mid-2007 continued through 2008, in line with deteriorating U.S. and global economic conditions. Lower consumption combined with higher product stocks resulted in narrower refining crack spreads compared with 2007. Margins on distillates, which were in high demand globally, were stronger than gasoline margins and we continued to optimize refinery throughput toward distillate production to maximize margins. Low gasoline margins resulted in lower crude throughputs at Lima. Crude supply disruptions associated with hurricanes Gustav, Hanna and Ike widened spreads for a period in the third quarter but impacted crude oil feedstock availability. Toledo was also limited in its ability to capitalize on wider sweet/sour differentials as production was impacted by planned process unit outages to complete priority maintenance and turnaround activities in the third quarter.

Crack spreads at Chicago averaged U.S. $11.17/bbl in 2008 compared with U.S. $17.68/bbl in 2007 and New York Harbor 3:2:1 refining crack spreads averaged U.S. $9.96/bbl in 2008 compared with U.S. $14.15/bbl in 2007. Our refining margin in 2008 was U.S. $0.46/bbl – the differential being partly driven by FIFO accounting and partly due to the different product mix at our refineries versus the standard 3:2:1 product mix. Our margin translated into Canadian dollars was negative $0.88/bbl. The impact of the weakening Canadian dollar in the fourth quarter and its impact on the translation of losses incurred in the quarter resulted in an overall negative margin on translation for the year. This is a result of earnings from the first nine months of 2008 translated at an average rate of U.S. $0.982 per Canadian dollar compared with larger losses in the fourth quarter translated at an average rate of U.S. $0.824 per Canadian dollar.

Processing costs for 2008 were impacted by the same factors impacting the fourth quarter combined with turnaround activity in the third quarter.

Downstream Capital Expenditures

Downstream capital expenditures totalled $288 million during 2008.

In Canada, capital expenditures totalled $155 million, $101 million for retail network remodeling, automation and facility upgrades, $28 million for upgrades and environmental protection at the Prince George and Lloydminster refineries, $19 million for upgrades at the Minnedosa and Lloydminster ethanol plants and $7 million for asphalt distribution and processing upgrades.

In the United States, capital expenditures totalled $133 million, $80 million at the Lima Refinery for the front-end engineering design for an isocracker debottleneck project and for various environmental protection and facility upgrades. At the Toledo Refinery capital expenditures totalled $53 million primarily for facility upgrades and environmental protection.

3.4 Corporate

Corporate Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars) income (expense)	**2008**	2007	**2008**	2007
Intersegment eliminations - net	**$ 75**	$ (16)	**$ 61**	$ (51)
Administration and other expenses	**11**	(15)	**(47)**	(63)
Stock based compensation	**60**	(40)	**33**	(88)
Depreciation and amortization	**(8)**	(7)	**(30)**	(25)
Interest - net	**(30)**	(40)	**(144)**	(129)
Foreign exchange	**275**	(6)	**335**	51
Income taxes	**(47)**	13	**(5)**	91
Net earnings (loss)	**$ 336**	$ (111)	**$ 203**	$ (214)

Intersegment eliminations are profit included in inventory that has not been sold to third parties at the end of the period.

In the fourth quarter of 2008, administration and other expenses included a gain of $30 million on the forward purchases of U.S. dollars.

The decrease in net interest expense during the fourth quarter of 2008 compared with a year earlier was primarily due to retirement of debt in the second and third quarters of 2008. Additional debt was issued during 2007 for the acquisition of the Lima Refinery.

Foreign Exchange Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)	**2008**	2007	**2008**	2007
(Gain) loss on translation of U.S. dollar denominated long-term debt				
Realized	**$ (5)**	$ -	**$ (5)**	$ -
Unrealized	**153**	(9)	**222**	(197)
	148	(9)	**217**	(197)
Cross currency swaps	**(58)**	3	**(83)**	62
Contribution receivable	**(191)**	-	**(228)**	-
Other (gains) losses	**(174)**	12	**(241)**	84
	$ (275)	$ 6	**$ (335)**	$ (51)
U.S./Canadian dollar exchange rates:				
At beginning of period	**U.S. $0.944**	U.S. $1.004	**U.S. $1.012**	U.S. $0.858
At end of period	**U.S. $0.817**	U.S. $1.012	**U.S. $0.817**	U.S.$1.012

Other gains and losses include realized and unrealized foreign exchange gains and losses on working capital.

Corporate Capital Expenditures

Corporate capital expenditures totalled $47 million in 2008 primarily for office equipment, renovations and information system upgrades.

Consolidated Income Taxes

During the fourth quarter of 2008, consolidated income taxes consisted of $176 million of current taxes and a recovery of $299 million of future taxes compared with current taxes of $110 million and a recovery of future taxes of $108 million in the same period of 2007. The increase in current taxes in the fourth quarter of 2008 compared with the fourth quarter of 2007 was due to the deferral of White Rose income in 2007 offset by lower U.S. taxable income in 2008. The increase in future tax recoveries in the fourth quarter of 2008 compared with the same period in 2007 was due to significant U.S. refining losses in 2008 offset by the Canadian Federal tax rate reduction booked in 2007.

4. Liquidity and Capital Resources

During the fourth quarter of 2008, cash flow from operating activities financed our capital expenditure requirements and dividend payment. In the year ended December 31, 2008, cash flow from operating activities financed our capital expenditure requirements, dividend payments, and repayment of debt. Husky maintained its strong position with debt of $1,957 million offset by cash on hand of $913 million for $1,044 million of net debt and we have no long term debt maturing until 2012. In addition, at December 31, 2008 we had $1.5 billion in unused committed credit facilities, with an additional $104 million in unused short-term uncommitted credit facilities.

Cash Flow Summary	Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars, except ratios)	**2008**	2007	**2008**	2007
Cash flow - operating activities	**$ 1,430**	$ 1,551	**$ 6,802**	$ 4,657
- financing activities	**$ (490)**	$ (616)	**$ (2,559)**	$ 433
- investing activities	**$ (993)**	$ (734)	**$ (3,538)**	$ (5,324)
Financial Ratios				
Debt to capital employed *(percent)*			**12.0**	19.5
Corporate reinvestment ratio *(percent)* [(1) (2)]			**66**	86

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

4.1 Operating Activities

Fourth Quarter

Cash generated from operating activities amounted to $1.4 billion compared with $1.6 billion in the fourth quarter of 2007. Of this, $1.1 billion represents a change in non-cash working capital compared with $142 million in the fourth quarter of 2007. The change is due to a decrease in accounts receivable and inventory resulting from a decline in commodity prices.

Lower cash flow from operations was primarily due to losses in the U.S. refining business, lower upstream commodity prices, lower upgrading throughput and lower unit margins.

Twelve Months

In 2008, cash generated from operating activities was $6.8 billion compared with $4.7 billion in 2007. Cash flow from operations was higher in 2008 mainly due to higher crude oil and natural gas prices, which were offset by lower margins in the U.S. downstream business.

4.2 Financing Activities

Fourth Quarter

Cash used in financing activities was $490 million compared with $616 million in the fourth quarter of 2007 primarily for the payment of dividends on common shares. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

Twelve Months

In 2008, cash used in financing activities was $2.6 billion compared with cash provided by financing activities of $433 million in 2007. In 2007, cash provided was used to acquire the Lima Refinery. The debt issuances and repayments presented in the Consolidated Statements of Cash Flows include multiple drawings and repayments under revolving debt facilities.

4.3 Investing Activities

Fourth Quarter

Cash used in investing activities amounted to $993 million compared with $734 million in the fourth quarter of 2007. Cash invested in both periods was used primarily for capital expenditures.

Twelve Months

In 2008, cash used in investing activities was $3.5 billion compared to $5.3 billion in 2007. Cash invested in both years was used primarily for capital expenditures, with $2.6 billion in 2007 for the Lima Refinery.

4.4 Sources of Capital

We are currently able to fund our capital programs principally by cash generated from operating activities and committed credit facilities. We also maintain access to sufficient capital via debt markets commensurate with our strong financial position. We are continually examining our options with respect to sources of long and short-term capital resources to ensure we maintain liquidity and the strength of our balance sheet.

Working capital is the amount by which current assets exceed current liabilities. At December 31, 2008, our working capital was $426 million compared with a working capital deficiency of $51 million at December 31, 2007.

(millions of dollars)	**Dec. 31 2008**	Dec. 31 2007	Change	
Current assets				
Cash and cash equivalents	**$ 913**	$ 208	$ 705	Strong earnings and cash flow
Accounts receivable	**1,344**	1,622	(278)	Lower crude oil prices
Inventories	**1,032**	1,190	(158)	Lower Lima inventory offset by inclusion of Toledo inventory
Prepaid expenses	**33**	28	5	
	3,322	3,048	274	
Current liabilities				
Accounts payable	**1,608**	1,460	(148)	Higher capital accruals
Accrued interest payable	**22**	20	(2)	
Income taxes payable	**419**	36	(383)	Higher taxable income
Other accrued liabilities	**847**	842	(5)	
Long-term debt due within one year	**-**	741	741	Repayment of bridge financing
	2,896	3,099	203	
Working capital (deficiency)	**$ 426**	$ (51)	$ 477	

Capital Structure	December 31, 2008	
(millions of dollars)	Outstanding	Available
Total short-term and long-term debt	$ 1,957	$ 1,604
Common shares, retained earnings and accumulated other comprehensive income	$ 14,388	

At December 31, 2008, we had unused committed long and short-term borrowing credit facilities totalling $1.5 billion. In addition, a further $270 million of uncommitted short-term borrowing credit facilities were available of which a total of $166 million were used in support of outstanding letters of credit.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility available of $10 million for general purposes. Our proportionate share is $5 million.

On June 12, 2008, we initiated a cash tender offer to purchase any and all of the 8.90% capital securities. As of June 12, 2008, there were U.S. $225 million of capital securities outstanding. The tender offer expired on July 11, 2008 at which date U.S. $214 million or 95% of the capital securities had been tendered. The settlement date occurred July 11, 2008. The remaining capital securities were redeemed on August 14, 2008.

On August 29, 2008, Husky redeemed the 6.95% medium-term notes - Series E due July 14, 2009. The principal amount was $200 million and the redemption price, including accrued interest, totalled $208 million.

During September 2008, Husky repurchased U.S. $43 million of the outstanding U.S. $450 million 6.80% notes due September 2037. On October 8, 2008, an additional U.S. $20 million was repurchased.

4.5 Credit Ratings

On March 31, 2008, DBRS upgraded our Senior Unsecured Notes and Debentures to A (low) and this remained unchanged at December 31, 2008.

Husky's current credit ratings for our unsecured long-term debt are BBB+ with a stable outlook from Standard & Poor's ("S&P") and Baa2 with a stable outlook from Moody's Investors Services Inc. ("Moody's").

4.6 Contractual Obligations and Commercial Commitments

Refer to Husky's 2007 annual and 2008 interim Management's Discussion and Analysis under the caption "Liquidity and Capital Resources," which summarizes contractual obligations and commercial commitments. At December 31, 2008, we had $2.4 billion of additional contractual obligations, which are expected to be settled in the following periods: 2009 - $805 million; 2010 - $328 million; 2011 - $279 million; 2012 - $175 million and thereafter - $780 million. Unconditional purchase agreements and exploration work agreements related to offshore China, Indonesia and Newfoundland exploration and development accounted for 92% of these additional contractual obligations.

4.7 Off Balance Sheet Arrangements

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

We engage, in the ordinary course of business, in the securitization of accounts receivable. At December 31, 2008 and 2007, we had no accounts receivable sold under the securitization program. The securitization program permits the sale of a maximum of $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 March 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.

4.8 Transactions with Related Parties

TransAlta Power, L.P. is an indirect subsidiary of Cheung Kong Infrastructure Holdings Ltd., which is majority owned by Hutchison Whampoa Limited, which owns 100% of U.F. Investments (Barbados) Ltd., a 34.58% shareholder in Husky. TransAlta Power, L.P. is a 49.99% owner of TransAlta Cogeneration, L.P., our partner in the Meridian cogeneration plant in Lloydminster, Saskatchewan. We sell natural gas to the Meridian cogeneration plant and other cogeneration plants owned by TransAlta Power, L.P. We received the market price or negotiated medium-term contracts based on market-related terms for these commodities. During 2008, we sold $125 million of natural gas to TransAlta Power, L.P.

5. Capability to Deliver Results and the Strategic Plan

Our capacity to deliver results and the strategic plan are described in our annual MD&A and also in our Annual Information Form that are available from www.sedar.com and www.sec.gov.

In summary, our current strategy is to continue to exploit oil and gas assets in Western Canada while expanding into new areas with large scale sustainable growth potential. Our plans include projects in Canada (the Alberta oil sands, the basins offshore Canada's East Coast and in the Central Mackenzie River Valley), Asia (the South China Sea, the Madura Strait and the East Java Sea) and offshore Greenland. In the midstream and downstream sectors we are enhancing performance and maximizing the value chain through integrating our businesses, optimizing plant operations and expanding plant and infrastructure.

6. Key Growth Highlights

The 2009 capital program of $2.6 billion focuses mainly on optimizing upstream production, midstream and downstream development and progressing major projects offshore Canada's East Coast and South East Asia. The 2009 capital budget has been established with a view to maintaining the strength of Husky's balance sheet during a period of significant economic and financial uncertainty. Capital expenditures will be focused on those projects offering the highest potential for returns and long-term growth. A number of projects previously discussed have been deferred pending improved economics.

Upstream

White Rose Development Projects

Delineation wells were completed at both the North Amethyst and West White Rose satellite fields in the fourth quarter, the results of which continue to be assessed with a view to optimizing production and reservoir depletion.

Progress continues on the North Amethyst development, the first White Rose satellite tie-back. Engineering and procurement activities remain on track with system integration testing due to commence in Q1 2009 followed by subsea equipment and flow line installation and tie-back to the SeaRose production vessel in summer 2009.

East Coast Exploration

The results of a 2,150 square kilometre 3-D seismic program that was completed during the third quarter are currently being evaluated to determine prospective drilling locations.

In December, the Mizzen exploration well (35% working interest) located in the Flemish Pass Basin, Exploration Licence ("EL") 1049 was spudded and is expected to reach total depth during the first quarter of 2009.

Offshore Greenland

The acquisition of 7,000 kilometres of 2-D seismic on Blocks 5 and 7 is now complete and is being evaluated. Husky is the operator and holds an 87.5% interest in these two blocks. We also hold a 43.75% working interest in Block 6 where the acquisition of 3,000 kilometres of 2-D seismic is complete.

Offshore China Liwan Delineation

The *West Hercules* deep water drilling rig spudded the first delineation well at the Liwan natural gas discovery on Block 29/26 in the South China Sea on November 20, 2008 and is currently preparing to test the first appraisal well. The initial deep water drilling program will include delineation wells at Liwan and exploration wells on other prospects in the area. The delineation program, including the exploration wells at the satellite prospects, will provide key information for the Liwan project's facilities design which will commence in 2009.

Offshore China Exploration

During the fourth quarter the shallow water jack-up drilling rig, *Frontier Discoverer* was secured and spud the QH 29-2-1 exploration well on January 22, 2009. This well will test a prospect on Block 39/05 in the Pearl River Mouth Basin immediately southwest of the Wenchang oil fields. In addition, an exploration drilling program is being planned in the East China Sea on Block 04/35 and in the Yinggehai Basin on blocks 35/18 and 50/14 near the Dong Fang and Ledong natural gas fields immediately west of Hainan Island.

Indonesia Exploration and Development

The Madura BD field development plan was approved by the government of Indonesia during the second quarter of 2008 and Husky (50%) and our partner, CNOOC Southeast Asia Limited expect to receive an extension to the Production Sharing Contract ("PSC") in 2009. Engineering work has been tendered and will commence upon receipt of the PSC extension.

In the East Bawean II PSC, in which we hold a 100% interest, the *Transocean Adriatic XI* jack-up rig has been secured to drill two exploration wells in the second quarter of 2009.

During October 2008, Husky was awarded a PSC from the government of Indonesia for a 100% interest in the North Sumbawa II Block comprising 5,000 square kilometres in the East Java Sea.

Sunrise Oil Sands Integrated Project

The development of the Sunrise Oil Sands Project (Husky 50%) will proceed in multiple phases. Bitumen production is expected to commence approximately four years following project sanction and is currently planned to increase to 200 mbbls/day, subject to project sanction and market conditions. The project is currently in an optimization phase to simplify the project's scope and take advantage of the recent downturn in the demand for goods and services. The development of this project is strategically linked to the repositioning project at the Toledo Refinery.

Tucker Oil Sands Project

A number of optimization strategies to address the ramp-up issues at the Tucker SAGD project were investigated during 2008. Production from eight new well pairs is showing encouraging results. These well pairs, which have been in SAGD mode for one to six months, have been placed in an optimized position in the reservoir. Drilling on the new Pad D has been deferred until commodity prices improve. During December 2008 Tucker's bitumen production averaged 4.8 mbbls/day. In January 2009 the Tucker oil sands project was moved into Husky's heavy oil and gas business unit to capitalize on synergies with our heavy oil thermal operations.

United States

In the Columbia River Basin in Washington State, Husky is currently participating in an exploration well, the Gray 31-23. The well had reached a depth of 3,800 metres in early January and planned total depth is 4,700 metres. The basin is characterized by over-pressure, tight sand natural gas formations.

Western Canada

Husky's Alkaline Surfactant Polymer ("ASP") enhanced oil recovery program, which currently includes ASP developments at Gull Lake and Fosterton, Saskatchewan and operating ASP applications at Warner and Crowsnest, Alberta, continues to move forward. The drilling program and pipeline construction at Gull Lake are complete and facility construction was approximately 60% complete at year end. Start up of the Gull Lake project is planned for the second quarter of 2009, subject to market conditions. The front-end engineering design for the Fosterton ASP project commenced in December. Husky holds a 62.4% working interest.

Husky's development of the McMullen property, which is located in the west central region of the Athabasca oil sands of northern Alberta, involves a cold production project and a thermal pilot project. At the end of 2008, the McMullen cold production project had 9 wells drilled, 6 of which were producing approximately 300 bbls/day. At the end of 2008, the thermal pilot project had 22 delineation wells and three water source wells completed. An application to construct a pilot project has been submitted to the Energy Resources Conservation Board.

During the fourth quarter of 2008, Husky participated (50% working interest) in approximately 50 coal bed methane wells to achieve a total of approximately 110 wells by the end of 2008.

In the Lloydminster heavy oil producing area, we continue to test various enhanced recovery techniques. In August 2008 we began CO_2 injection at our second cold solvent pilot project. This pilot project is designed to test oil recovery and production rates utilizing CO_2 and propane.

Downstream

Lima, Ohio Refinery

An engineering evaluation has been completed to determine the reconfiguration of the Lima Refinery to increase its capacity to process heavier, less costly, crude oil feedstock; realize complex refining processes to enhance margins; and increase flexibility in product outputs. The current configuration at the Lima Refinery allows it to process a predominantly light sweet crude oil feedstock. This limits our ability to process a lower cost heavier crude feedstock to meet seasonal and longer term market demands. This project has been deferred subject to improved market conditions.

Toledo, Ohio Refinery

Husky and BP continued to progress the Continuous Catalyst Regeneration Reformer Project. The scope of this project is to replace two naphtha reformers and one hydrogen plant with one 42,000 bbls/day continuous catalyst regeneration system plant. The project's objectives are to effectively and safely improve profitability while reducing operating risk, meet future product requirements and reduce the environmental footprint. A project team has also been launched to reposition the refinery to process bitumen from the first two phases of the Sunrise oil sands integrated project. Due to the integrated nature of this project, progress will be coincident with the upstream development requirements. The refinery continues to make progress on a multi-year program to improve operational integrity and plant performance.

7. Risk Management

Husky is exposed to market risks and various operational risks. For a detailed discussion of these risks see our 2007 Annual Information Form filed on the Canadian Securities Administrator's web site, www.sedar.com, the Securities and Exchange Commission's web site, www.sec.gov or our web site www.huskyenergy.com.

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. The global financial and economic crisis which developed in 2008 has increased the risk associated with timely access to debt capital and banking markets and the current market instability may have an impact on our ability to borrow in the capital debt markets at acceptable rates.

Interest Rate Risk Management

In 2008, interest rate risk management activities resulted in a decrease to interest expense of less than $1 million.

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 2008, these swaps resulted in an offset to interest expense amounting to $1 million. The interest rate swaps were discontinued as a fair value hedge on August 29, 2008 given the $200 million medium-term notes were redeemed. For the remainder of 2008, the fair value changes were included in other expenses.

The amortization of previous interest rate swap terminations resulted in an additional $5 million offset to interest expense in 2008.

Cross currency swaps resulted in an addition to interest expense of $6 million in 2008.

Foreign Currency Risk Management

At December 31, 2008, we had the following cross currency debt swaps in place:

- U.S. $150 million at 6.25% swapped at $1.41 to $211 million at 7.41% until June 15, 2012.
- U.S. $75 million at 6.25% swapped at $1.19 to $89 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 December 31, 2008, we had the following freestanding derivatives in place where Husky had entered into forward purchases of U.S. dollars (refer to Note 16 to the Consolidated Financial Statements):

- U.S. $98 million bought at $0.9860 for $97 million from January 2008 to June 2011.
- U.S. $98 million bought at $0.9777 for $96 million from January 2008 to June 2011.

At December 31, 2008, the cost of a U.S. dollar in Canadian currency was $1.22.

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 December 31, 2008, 100% or $2.0 billion of our long-term debt was denominated in U.S. dollars. The percentage of our long-term debt exposed to the U.S./Canadian exchange rate decreases to 78% when cross currency swaps are considered.

Effective July 1, 2007, our U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the net investment in the U.S. refining operations, which are considered self-sustaining. During the second quarter of 2008, we repaid our bridge financing of U.S. $750 million. In the third quarter of 2008, the Company repurchased U.S. $43 million of bonds that were classified as a net investment hedge. In October, an additional U.S. $20 million were repurchased. As a result, the net investment hedge is limited to the remaining U.S. $687 million. As at December 31, 2008, foreign exchange losses arising from the translation of the debt were $165 million, net of tax of $27 million, which was recorded in "Other Comprehensive Income".

8. 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, 2007, available at www.sedar.com.

9. Accounting Policies

New Accounting Standards Adopted

As disclosed in Management's Discussion and Analysis for the year ended December 31, 2007, on January 1, 2008, we adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3031 "Inventories," Section 3863 "Financial Instruments – Presentation," Section 3862 "Financial Instruments – Disclosures" and Section 1535 "Capital Disclosures." The adoption of these standards has had no material impact on Husky's net earnings or cash flows. Additional information on the effects of the adoption of these standards can be found in Notes 3, 4 and 5 to the Consolidated Financial Statements.

Recent Accounting Pronouncements

In February 2008, the CICA issued CICA section 3064, "Goodwill and Intangible Assets," which will replace CICA section 3062 of the same name. As a result of issuing this guidance, CICA section 3450, "Research and Development Costs," and Emerging Issues Committee Abstract No. 27, "Revenues and Expenditures during the Pre-Operating Period," will be withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with CICA section 1000, "Financial Statement Concepts." Section 3064 will eliminate the current practice of recognizing items as assets that do not meet the section 1000 definition and recognition criteria.

As of January 1, 2009, the Company will retroactively adopt CICA section 3064. The impact of this standard will be immaterial to the Company.

In December 2008, the CICA issued section 1582 "Business Combinations," which will replace CICA section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 will be effective for Husky on January 1, 2011 with prospective application.

In January 2006, the Canadian Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of the AcSB's strategic plan, Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian GAAP for years beginning on or after January 1, 2011. An omnibus exposure draft was issued by the AcSB in the second quarter of 2008, which incorporates IFRS into the CICA Handbook and prescribes the transitional provisions for adopting IFRS.

Husky has completed the diagnostic assessment phase by performing comparisons of the differences between Canadian GAAP and IFRS and is currently assessing the effects of adoption and finalizing its conversion plan. We have determined that accounting for property, plant and equipment will be impacted by the conversion to IFRS. Husky currently follows full cost accounting as prescribed in Accounting Guideline ("AcG') 16, "Oil and Gas Accounting – Full Cost." Conversion from Canadian GAAP to IFRS may have an impact on how we account for costs pertaining to oil and gas activities, in particular those related to the pre-exploration and development phases. The conversion to IFRS will also result in other impacts, some of which may be significant in nature and these continue to be assessed by the Company. At this time, the impact on Husky's financial position and results of operations is not reasonably determinable or estimable for any of the IFRS conversion impacts identified. We will continue to monitor any changes in the adoption of IFRS and will update plans as necessary.

10. Reader Advisories

This interim report 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 2007 Annual Information Form filed in 2008 with Canadian regulatory agencies and Form 40-F filed with the Securities and Exchange Commission, the U.S. regulatory agency. These documents are available at www.sedar.com, at www.sec.gov and at www.huskyenergy.com.

Use of Pronouns and Other Terms Denoting Husky

In this interim report, 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 interim report with respect to results for the three months ended December 31, 2008 are compared with results for the three months ended December 31, 2007 and results for the year ended December 31, 2008 are compared with results for the year ended December 31, 2007. Discussions with respect to Husky's financial position as at December 31, 2008 are compared with its financial position at December 31, 2007.

Additional Reader Guidance

- The Consolidated Financial Statements and comparative financial information included in this interim report have been prepared in accordance with Canadian 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.

Non-GAAP Measures

Disclosure of Cash Flow from Operations

This interim report 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. Cash flow from operations or earnings is presented in our financial reports to assist management and investors in analyzing operating performance by business in the stated period. 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:

		Three months ended Dec. 31		Year ended Dec. 31	
(millions of dollars)		**2008**	2007	**2008**	2007
Non-GAAP	Cash flow from operations	**$ 339**	$ 1,425	**$ 5,970**	$ 5,426
	Settlement of asset retirement obligations	**(19)**	(16)	**(56)**	(51)
	Change in non-cash working capital	**1,110**	142	**888**	(718)
GAAP	Cash flow - operating activities	**$ 1,430**	$ 1,551	**$ 6,802**	$ 4,657

Disclosure of Adjusted Net Earnings

This interim report contains the term "Adjusted Net Earnings," which is a non-GAAP measure of net earnings adjusted for certain items that are not an indicator of the Company's on-going financial performance. The following table shows the reconciliation of net earnings to Adjusted Net Earnings for the periods shown:

		Three months ended Dec. 31	
(millions of dollars)		**2008**	2007
GAAP	Net earnings	**$ 232**	$ 1,074
	Net inventory write-downs	**382**	-
	Non-recurring tax adjustments	**-**	(365)
Non-GAAP	Adjusted Net Earnings	**$ 614**	$ 709

Disclosure of Operating Netback

Operating netback is a common non-GAAP metric used in the oil and gas industry. This measurement helps management and investors to evaluate the specific operating performance by product at the oil and gas lease level. It is equal to product revenue less transportation costs, royalties and lease operating costs divided by either a barrel of oil equivalent or a mcf of gas equivalent.

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 wellhead.

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 the requirements 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 Husky's Annual Information Form for the year ended December 31, 2007 filed with securities regulatory authorities for further information.

Cautionary Note to U.S. Investors

The United States Securities and Exchange Commission permits U.S. oil and gas companies, in their filings with the SEC, to disclose only proved reserves, that is reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made. Husky uses certain terms in this release, such as "probable reserves" and "possible reserves," that the SEC's guidelines strictly prohibit in filings with the SEC by U.S. oil and gas companies. U.S. investors should refer to Husky's Annual Report on Form 40-F available from the Company or the SEC for further reserve disclosure.

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*
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*

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	*Includes capitalized administrative expenses and capitalized interest but does not include proceeds or other assets*
Capital Program	*Capital expenditures not including capitalized administrative expenses or capitalized interest*
Cash Flow from Operations	*Earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital*
Corporate Reinvestment Ratio	*Net capital expenditures (capital expenditures net of proceeds from asset sales) plus corporate acquisitions (net assets acquired) divided by cash flow from operations*
Dated Brent	*Prices which are dated less than 15 days prior to loading for delivery*
Debt to Capital Employed	*Total debt divided by total debt and shareholders' equity*
Delineation Well	*A well in close proximity to an oil or gas discovery well that helps determine the areal extent of the reservoir*
Diluent	*A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil to facilitate transmissibility through a pipeline*
Embedded Derivative	*Implicit or explicit term(s) in a contract that affects some or all of the cash flows or the value of other exchanges required by the contract*
Equity	*Shares, retained earnings and accumulated other comprehensive income*
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*
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*
Return on Capital Employed	*Net earnings plus after tax interest expense divided by average capital employed*
Return on Shareholders' Equity	*Net earnings divided by average shareholders' equity*
Stratigraphic Well	*A geologically directed test well to obtain information. These wells are usually drilled without the intention of being completed for production*
Synthetic Oil	*A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content*
Three Dimensional (3-D) Seismic	*Seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line*
Total Debt	*Long-term debt including current portion and bank operating loans*
Turnaround	*Scheduled performance of plant or facility maintenance*

11. Forward-Looking Statements and Information

Certain statements in this release are forward-looking statements and 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 hereby provides cautionary statements identifying important factors that could cause 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," "target," "schedules" and "outlook") are not historical facts and are forward-looking and may involve estimates and assumptions and are subject to risks, uncertainties and other factors some of which are beyond the Company's control and difficult to predict. Accordingly, these factors could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. Therefore, any such forward-looking statements are qualified in their entirety by reference to the factors discussed throughout this release.

In particular, forward-looking statements in this release include, but are not limited to the Company's development plans for the North Amethyst, West White Rose oil fields and South White Rose oil field extension, and the Company's exploration well in the Flemish Pass Basin, production optimization plans for the Tucker in-situ oil sands project, Sunrise multiphase development plans, development plans for the McMullen property, exploration well in the Columbia River Basin, exploration and delineation drilling plans for the South China Sea, the receipt of an extension of the PSC for the Madura BD natural gas and NGL field and two-well work program for the East Bawean II exploration block, plans to install various enhanced recovery schemes and drilling programs in Western Canada and review options in respect of reconfiguring and expanding the Lima Refinery and plans to modify the Toledo Refinery.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this release are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third party consultants, suppliers, regulators and other sources.

The Company's Annual Report to shareholders and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe the risks, material assumptions and other factors that could influence actual results and which are incorporated herein by reference.

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) (unaudited)	**December 31 2008**	December 31 2007
Assets		
Current assets		
Cash and cash equivalents	**$ 913**	$ 208
Accounts receivable	**1,344**	1,622
Inventories	**1,032**	1,190
Prepaid expenses	**33**	28
	3,322	3,048
Property, plant and equipment *(note 6)*	**34,264**	29,407
Less accumulated depletion, depreciation and amortization	**13,425**	11,602
	20,839	17,805
Goodwill *(note 8)*	**779**	660
Contribution receivable *(note 6)*	**1,448**	-
Other assets	**134**	184
	$ 26,522	$ 21,697
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 2,896**	$ 2,358
Long-term debt due within one year *(note 10)*	**-**	741
	2,896	3,099
Long-term debt *(note 10)*	**1,957**	2,073
Contribution payable *(note 6)*	**1,659**	-
Other long-term liabilities *(note 11)*	**898**	918
Future income taxes	**4,724**	3,957
Commitments and contingencies *(note 12)*		
Shareholders' equity		
Common shares *(note 13)*	**3,568**	3,551
Retained earnings	**10,461**	8,176
Accumulated other comprehensive income	**359**	(77)
	14,388	11,650
	$ 26,522	$ 21,697
Common shares outstanding *(millions) (note 13)*	**849.4**	849.0

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 Dec. 31 **2008**	Three months ended Dec. 31 2007	Year ended Dec. 31 **2008**	Year ended Dec. 31 2007
Sales and operating revenues, net of royalties	**$ 4,701**	$ 4,760	**$ 24,701**	$ 15,518
Costs and expenses				
Cost of sales and operating expenses	**4,325**	3,081	**17,701**	9,296
Selling and administration expenses	**70**	71	**284**	219
Stock-based compensation *(note 13)*	**(60)**	40	**(33)**	88
Depletion, depreciation and amortization	**489**	462	**1,832**	1,806
Interest - net *(note 10)*	**31**	40	**147**	130
Foreign exchange *(note 10)*	**(275)**	6	**(335)**	(51)
Other - net	**12**	(16)	**(45)**	(97)
	4,592	3,684	**19,551**	11,391
Earnings before income taxes	**109**	1,076	**5,150**	4,127
Income taxes				
Current	**176**	110	**901**	347
Future	**(299)**	(108)	**495**	566
	(123)	2	**1,396**	913
Net earnings	**232**	1,074	**3,754**	3,214
Other comprehensive income				
Cumulative foreign currency translation adjustment	**420**	(35)	**607**	(175)
Hedge of net investment, net of tax *(note 16)*	**(99)**	11	**(165)**	102
Derivatives designated as cash flow hedges, net of tax *(note 16)*	**3**	10	**(6)**	14
	324	(14)	**436**	(59)
Comprehensive income	**$ 556**	$ 1,060	**$ 4,190**	$ 3,155
Earnings per share				
Basic and diluted	**$ 0.27**	$ 1.26	**$ 4.42**	$ 3.79
Weighted average number of common shares outstanding *(millions)*				
Basic and diluted	**849.3**	849.0	**849.2**	848.8

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

Consolidated Statements of Changes in Shareholders' Equity

(millions of dollars) (unaudited)	Three months ended Dec. 31 **2008**	Three months ended Dec. 31 2007	Year ended Dec. 31 **2008**	Year ended Dec. 31 2007
Common shares				
Beginning of period	**$ 3,567**	$ 3,549	**$ 3,551**	$ 3,533
Options exercised	**1**	2	**17**	18
End of period	**3,568**	3,551	**3,568**	3,551
Retained earnings				
Beginning of period	**10,654**	7,382	**8,176**	6,087
Net earnings	**232**	1,074	**3,754**	3,214
Dividends on common shares				
Ordinary	**(425)**	(280)	**(1,469)**	(917)
Special	**-**	-	**-**	(212)
Adoption of financial instruments	**-**	-	**-**	4
End of period	**10,461**	8,176	**10,461**	8,176
Accumulated other comprehensive income				
Beginning of period	**35**	(63)	**(77)**	-
Adoption of financial instruments	**-**	-	**-**	(18)
Other comprehensive income *(note 16)*				
Cumulative foreign currency translation adjustment	**420**	(35)	**607**	(175)
Hedge of net investment, net of tax	**(99)**	11	**(165)**	102
Derivatives designated as cash flow hedges, net of tax	**3**	10	**(6)**	14
	324	(14)	**436**	(59)
End of period	**359**	(77)	**359**	(77)
Shareholders' equity	**$ 14,388**	$ 11,650	**$ 14,388**	$ 11,650

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 Dec. 31 **2008**	Three months ended Dec. 31 2007	Year ended Dec. 31 **2008**	Year ended Dec. 31 2007
Operating activities				
Net earnings	**$ 232**	$ 1,074	**$ 3,754**	$ 3,214
Items not affecting cash				
Accretion *(note 11)*	**14**	12	**54**	47
Depletion, depreciation and amortization	**489**	462	**1,832**	1,806
Future income taxes	**(299)**	(108)	**495**	566
Foreign exchange	**(101)**	(8)	**(94)**	(135)
Other	**4**	(7)	**(71)**	(72)
Settlement of asset retirement obligations *(note 11)*	**(19)**	(16)	**(56)**	(51)
Change in non-cash working capital *(note 7)*	**1,110**	142	**888**	(718)
Cash flow - operating activities	**1,430**	1,551	**6,802**	4,657
Financing activities				
Bank operating loans financing - net	**-**	(44)	**-**	-
Long-term debt issue	**-**	600	**949**	7,222
Long-term debt repayment	**(20)**	(601)	**(2,205)**	(5,722)
Debt issue costs	**-**	-	**-**	(8)
Proceeds from exercise of stock options	**-**	1	**5**	5
Proceeds from monetization of financial instruments	**-**	-	**12**	-
Dividends on common shares	**(425)**	(280)	**(1,469)**	(1,129)
Other	**6**	-	**3**	-
Change in non-cash working capital *(note 7)*	**(51)**	(292)	**146**	65
Cash flow - financing activities	**(490)**	(616)	**(2,559)**	433
Available for investing	**940**	935	**4,243**	5,090
Investing activities				
Capital expenditures	**(1,388)**	(840)	**(4,060)**	(2,931)
Corporate acquisition	**-**	-	**-**	(2,589)
Joint venture arrangement *(note 6)*	**-**	-	**127**	-
Asset sales	**4**	1	**37**	333
Other	**(13)**	(2)	**(13)**	(44)
Change in non-cash working capital *(note 7)*	**404**	107	**371**	(93)
Cash flow - investing activities	**(993)**	(734)	**(3,538)**	(5,324)
Increase (decrease) in cash and cash equivalents	**(53)**	201	**705**	(234)
Cash and cash equivalents, beginning of period	**966**	7	**208**	442
Cash and cash equivalents, end of period	**$ 913**	$ 208	**$ 913**	$ 208

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

Notes to the Consolidated Financial Statements

Year ended December 31, 2008 *(unaudited)*
Except where indicated, all dollar amounts are in millions.

Note 1 Segmented Financial Information

	Upstream		Midstream				Downstream				Corporate and Eliminations [1]		Total	
			Upgrading		Infrastructure and Marketing		Canadian Refined Products		U.S. Refining and Marketing					
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007	**2008**	2007
Three months ended December 31														
Sales and operating revenues, net of royalties	**$ 1,295**	$ 1,568	**$ 445**	$ 530	**$ 2,456**	$ 2,617	**$ 673**	$ 758	**$ 1,474**	$ 1,340	**$ (1,642)**	$ (2,053)	**$ 4,701**	$ 4,760
Costs and expenses														
Operating, cost of sales, selling and general	**455**	358	**373**	358	**2,408**	2,509	**636**	699	**2,263**	1,234	**(1,788)**	(1,982)	**4,347**	3,176
Depletion, depreciation and amortization	**394**	396	**9**	8	**8**	7	**20**	19	**50**	25	**8**	7	**489**	462
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**1**	-	**30**	40	**31**	40
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(275)**	6	**(275)**	6
	849	754	**382**	366	**2,416**	2,516	**656**	718	**2,314**	1,259	**(2,025)**	(1,929)	**4,592**	3,684
Earnings (loss) before income taxes	**446**	814	**63**	164	**40**	101	**17**	40	**(840)**	81	**383**	(124)	**109**	1,076
Current income taxes	**123**	41	**21**	5	**37**	18	**8**	4	**(33)**	14	**20**	28	**176**	110
Future income taxes	**(19)**	(91)	**(2)**	22	**(25)**	2	**(7)**	(16)	**(273)**	16	**27**	(41)	**(299)**	(108)
Net earnings (loss)	**$ 342**	$ 864	**$ 44**	$ 137	**$ 28**	$ 81	**$ 16**	$ 52	**$ (534)**	$ 51	**$ 336**	$ (111)	**$ 232**	$ 1,074
Capital expenditures - Three months ended Dec. 31 [2]	**$ 1,174**	$ 706	**$ 23**	$ 44	**$ 58**	$ 15	**$ 63**	$ 52	**$ 70**	$ 16	**$ 14**	$ 20	**$ 1,402**	$ 853
Year ended Dec. 31														
Sales and operating revenues, net of royalties	**$ 7,889**	$ 6,222	**$ 2,435**	$ 1,524	**$13,544**	$10,217	**$ 3,564**	$ 2,916	**$ 7,802**	$ 2,383	**$(10,533)**	$ (7,744)	**$24,701**	$15,518
Costs and expenses														
Operating, cost of sales, selling and general	**1,627**	1,308	**2,054**	1,127	**13,192**	9,838	**3,337**	2,608	**8,277**	2,167	**(10,580)**	(7,542)	**17,907**	9,506
Depletion, depreciation and amortization	**1,505**	1,615	**31**	25	**31**	28	**81**	66	**154**	47	**30**	25	**1,832**	1,806
Interest - net	**-**	-	**-**	-	**-**	-	**-**	-	**3**	1	**144**	129	**147**	130
Foreign exchange	**-**	-	**-**	-	**-**	-	**-**	-	**-**	-	**(335)**	(51)	**(335)**	(51)
	3,132	2,923	**2,085**	1,152	**13,223**	9,866	**3,418**	2,674	**8,434**	2,215	**(10,741)**	(7,439)	**19,551**	11,391
Earnings (loss) before income taxes	**4,757**	3,299	**350**	372	**321**	351	**146**	242	**(632)**	168	**208**	(305)	**5,150**	4,127
Current income taxes	**585**	122	**84**	10	**126**	68	**28**	17	**(24)**	28	**102**	102	**901**	347
Future income taxes	**795**	581	**21**	80	**(29)**	30	**12**	33	**(207)**	35	**(97)**	(193)	**495**	566
Net earnings (loss)	**$ 3,377**	$ 2,596	**$ 245**	$ 282	**$ 224**	$ 253	**$ 106**	$ 192	**$ (401)**	$ 105	**$ 203**	$ (214)	**$ 3,754**	$ 3,214
Capital expenditures - Year ended Dec. 31 [2]	**$ 3,580**	$ 2,388	**$ 99**	$ 217	**$ 94**	$ 92	**$ 155**	$ 212	**$ 133**	$ 21	**$ 47**	$ 44	**$ 4,108**	$ 2,974
Goodwill additions – Year ended Dec. 31	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ -	**$ -**	$ 536	**$ -**	$ -	**$ -**	$ 536
Total assets - As at Dec. 31	**$15,653**	$14,395	**$ 1,349**	$ 1,405	**$ 1,486**	$ 1,134	**$ 1,381**	$ 1,335	**$ 5,383**	$ 3,058	**$ 1,270**	$ 370	**$26,522**	$21,697

[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, the Lima acquisition and the BP transaction.*

Except where indicated, all dollar amounts are in millions.

Geographical Financial Information

	Canada		United States		Other International		Total	
	2008	2007	**2008**	2007	**2008**	2007	**2008**	2007
Three months ended December 31								
Sales and operating revenues, net of royalties	**$ 2,924**	$ 3,088	**$ 1,728**	$ 1,603	**$ 49**	$ 69	**$ 4,701**	$ 4,760
Capital expenditures [(1)]	**1,210**	812	**80**	16	**112**	25	**1,402**	853
Year ended December 31								
Sales and operating revenues, net of royalties	**$15,213**	$11,736	**$ 9,172**	$ 3,494	**$ 316**	$ 288	**$24,701**	$15,518
Capital expenditures [(1)]	**3,685**	2,877	**193**	21	**230**	76	**4,108**	2,974
As at December 31								
Property, plant and equipment, net	**$16,234**	$16,017	**$ 4,093**	$ 1,417	**$ 512**	$ 371	**$20,839**	$17,805
Goodwill [(2)]	**160**	160	**619**	500	**-**	-	**779**	660

[(1)] *Excludes capitalized costs related to asset retirement obligations incurred during the period, the Lima acquisition and the BP transaction.*
[(2)] *Goodwill relates to Western Canada in the upstream segment and to the Lima Refinery in the downstream segment - U.S. refining and marketing.*

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, 2007, 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, 2007. Certain prior years' amounts have been reclassified to conform with current presentation.

Note 3 Changes in Accounting Policies

Inventories

Effective January 1, 2008, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3031, "Inventories," which replaced CICA section 3030 of the same name. The new guidance provides additional measurement and disclosure requirements and requires the Company to reverse previous impairment write-downs when there is a change in the situation that caused the impairment. The transitional provisions of section 3031 provided entities with the option of applying this guidance retrospectively and restating prior periods in accordance with section 1506, "Accounting Changes" or adjusting opening retained earnings and not restating prior periods. The adoption of this standard did not have an impact on the Company's financial statements.

Note 4 New Disclosures

a) Financial Instruments - Disclosure and Presentation

Effective January 1, 2008, the Company adopted CICA section 3862, "Financial Instruments - Disclosures" and CICA section 3863, "Financial Instruments - Presentation," which replaced CICA section 3861, "Financial Instruments - Disclosure and Presentation." Section 3862 outlines the disclosure requirements for financial instruments and non-financial derivatives. This guidance prescribes an increased importance on risk disclosures associated with recognized and unrecognized financial instruments and how such risks are managed. Specifically, section 3862 requires disclosure of the significance of financial instruments on the Company's financial position. In addition, the guidance outlines revised requirements for the disclosure of qualitative and quantitative information regarding exposure to risks arising from financial instruments.

The presentation requirements under section 3863 are relatively unchanged from section 3861. Refer to Note 16, "Financial Instruments and Risk Management" for the additional disclosures under section 3862.

b) Capital Disclosures

Effective January 1, 2008, the Company adopted CICA section 1535, "Capital Disclosures." This new guidance requires disclosure about the Company's objectives, policies and processes for managing capital. These disclosures include a description of what the Company manages as capital, the nature of externally imposed capital requirements, how the requirements are incorporated into the Company's management of capital, whether the requirements have been complied with, or consequence of non-compliance and an explanation of how the Company is meeting its objectives for managing capital. In addition, quantitative disclosures regarding capital are required. Refer to Note 17, "Capital Disclosures."

Note 5 Pending Accounting Pronouncements

a) Goodwill and Intangible Assets

In February 2008, the CICA issued CICA section 3064, "Goodwill and Intangible Assets," which will replace CICA section 3062 of the same name. As a result of issuing this guidance, CICA section 3450, "Research and Development Costs," and Emerging Issues Committee Abstract No. 27, "Revenues and Expenditures during the Pre-Operating Period," will be withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with CICA section 1000, "Financial Statement Concepts." Section 3064 will eliminate the current practice of recognizing items as assets that do not meet the section 1000 definition and recognition criteria. Under this new guidance, fewer items meet the criteria for capitalization. Section 3064 is effective for Husky on January 1, 2009. The impact of this standard will be immaterial to the Company.

b) Business Combinations

In December 2008, the CICA issued section 1582 "Business Combinations," which will replace CICA section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 will be effective for Husky on January 1, 2011 with prospective application.

Note 6 Joint Ventures

a) BP

On March 31, 2008, the Company completed a transaction with BP, which resulted in the formation of a 50/50 joint venture upstream entity and a 50/50 joint venture downstream entity.

The upstream entity is a Canadian partnership to which Husky has contributed the Sunrise oil sands assets with a fair value of U.S. $2.5 billion as at January 1, 2008, plus capital expenditures for the three-month period ended March 31, 2008 of $15 million. BP's contribution was U.S. $250 million cash and a contribution receivable for the balance of U.S. $2.25 billion and $15 million. The contribution receivable accretes at a rate of 6% and is payable between December 31, 2008 and December 31, 2015 with the final balance due and payable by December 31, 2015. The upstream entity is included as part of the Upstream segment.

The downstream entity is a U.S. limited liability company ("LLC") to which BP has contributed the Toledo Refinery with a fair value of U.S. $2.5 billion, plus capital expenditures for the three-month period ended March 31, 2008 of U.S. $11 million and inventories of U.S. $388 million, other net assets of U.S. $3 million, less inventory related payables of U.S. $23 million and adjusted earnings of U.S. $39 million. Husky's contribution was U.S. $250 million cash and a contribution payable for the balance of U.S. $2.6 billion. The contribution payable accretes at a rate of 6% and is payable between December 31, 2008 and December 31, 2015 with the final balance due and payable by December 31, 2015. The timing of payments during this period will be determined by the capital expenditures made at the refinery during this same period. The downstream entity is included as part of the U.S. Refining and Marketing segment. This entity is a self-sustaining foreign operation.

Except where indicated, all dollar amounts are in millions.

Both joint ventures are being accounted for using proportionate consolidation. The amounts recorded in the financial statements represent the Company's 50% interest in the joint ventures.

b) CNOOC Southeast Asia Limited

In April 2008, a subsidiary of the Company, Husky Oil Madura Partnership ("HOMP"), entered into an agreement with CNOOC Southeast Asia Limited ("CNOOCSE"), which resulted in the acquisition by CNOOCSE of a 50% equity interest in Husky Oil (Madura) Limited, a subsidiary of HOMP, for a consideration of $127 million (U.S. $125 million) resulting in a gain of $69 million included in other - net in the Consolidated Statements of Earnings and Comprehensive Income. Husky Oil (Madura) Limited holds a 100% interest in the Madura Strait Production Sharing Contract. The resulting joint venture arrangement is being accounted for using the proportionate consolidation method.

Note 7 Cash Flows - Change in Non-cash Working Capital

	Three months ended Dec. 31		Year ended Dec. 31	
	2008	2007	**2008**	2007
a) Change in non-cash working capital was as follows:				
Decrease (increase) in non-cash working capital				
Accounts receivable	**$ 910**	$ (281)	**$ 453**	$ (345)
Inventories	**702**	(114)	**522**	(212)
Prepaid expenses	**31**	23	**2**	1
Accounts payable and accrued liabilities	**(180)**	329	**428**	(190)
Change in non-cash working capital	**$ 1,463**	$ (43)	**$ 1,405**	$ (746)
Relating to:				
Operating activities	**$ 1,110**	$ 142	**$ 888**	$ (718)
Financing activities	**(51)**	(292)	**146**	65
Investing activities	**404**	107	**371**	(93)
b) Other cash flow information:				
Cash taxes paid	**$ 125**	$ 61	**$ 615**	$ 926
Cash interest paid	**16**	57	**103**	162

Cash and cash equivalents at December 31, 2008, included $269 million of cash and $644 million of short-term investments with maturities less than 90 days.

Note 8 Goodwill

	Three months ended Dec. 31		Year ended Dec. 31	
	2008	2007	**2008**	2007
Balance at beginning of period	**$ 696**	$ 636	**$ 660**	$ 160
Acquired during the period	**-**	-	**-**	536
Adjustment to purchase price allocation	**-**	33	**-**	-
Foreign currency translation of goodwill in self-sustaining U.S. operations	**83**	(9)	**119**	(36)
Balance at December 31	**$ 779**	$ 660	**$ 779**	$ 660

Except where indicated, all dollar amounts are in millions.

Note 9 Bank Operating Loans

At December 31, 2008, the Company had unsecured short-term borrowing lines of credit with banks totalling $370 million (December 31, 2007 - $270 million). As at December 31, 2008 and 2007, there were no bank operating loans outstanding. As of December 31, 2008, letters of credit under these lines of credit totalled $166 million (December 31, 2007 - $73 million).

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million available for general purposes. The Company's proportionate share is $5 million. As at December 31, 2008, there was no balance outstanding under this credit facility.

Note 10 Long-term Debt

		December 31			
	Maturity	**2008**	2007	**2008**	2007
		Cdn $ Amount		*U.S. $ Denominated*	
Long-term debt					
Medium-term notes		**$ -**	$ 203	**$ -**	$ -
6.25% notes	2012	**490**	395	**400**	400
7.55% debentures	2016	**245**	198	**200**	200
6.20% notes	2017	**367**	296	**300**	300
6.15% notes	2019	**367**	296	**300**	300
8.90% capital securities		**-**	223	**-**	225
6.80% notes	2037	**474**	445	**387**	450
Debt issue costs [(1)]		**(18)**	(20)	**-**	-
Unwound interest rate swaps		**32**	37	**-**	-
		$ 1,957	$ 2,073	**$ 1,587**	$ 1,875
Long-term debt due within one year					
Bridge financing		**$ -**	$ 741	**$ -**	$ 750

[(1)] *Calculated using the effective interest rate method.*

On June 12, 2008, Husky initiated a cash tender offer to purchase any and all of the 8.90% capital securities. The tender offer expired on July 11, 2008 at which date U.S. $214 million or 95% of the capital securities had been tendered. The settlement date occurred July 11, 2008. The remaining capital securities were redeemed on August 14, 2008.

On August 29, 2008, Husky redeemed the 6.95% medium-term notes - Series E due July 14, 2009. The principal amount was $200 million and the redemption price, including accrued interest, totalled $208 million.

During September 2008, Husky repurchased U.S. $43 million of the outstanding U.S. $450 million 6.80% notes due September 2037. In October, an additional U.S. $20 million was repurchased.

Except where indicated, all dollar amounts are in millions.

Interest - net consisted of:

	Three months ended Dec. 31		Year ended Dec. 31	
	2008	2007	**2008**	2007
Interest expense				
Long-term debt	**$ 33**	$ 45	**$ 154**	$ 151
Contribution payable	**23**	-	**63**	-
Short-term debt	**1**	1	**5**	6
	57	46	**222**	157
Amount capitalized	**-**	(6)	**-**	(19)
	57	40	**222**	138
Interest income				
Contribution receivable	**(20)**	-	**(55)**	-
Other	**(6)**	-	**(20)**	(8)
	(26)	-	**(75)**	(8)
	$ 31	$ 40	**$ 147**	$ 130

Foreign exchange consisted of:

	Three months ended Dec. 31		Year ended Dec. 31	
	2008	2007	**2008**	2007
(Gain) loss on translation of U.S. dollar denominated long-term debt	**$ 148**	$ (9)	**$ 217**	$ (197)
Cross currency swaps	**(58)**	3	**(83)**	62
Contribution receivable	**(191)**	-	**(228)**	-
Other (gains) losses	**(174)**	12	**(241)**	84
(Gain) loss	**$ (275)**	$ 6	**$ (335)**	$ (51)

Note 11 Other Long-term Liabilities

Asset Retirement Obligations

Changes to asset retirement obligations were as follows:

	Year ended Dec. 31	
	2008	2007
Asset retirement obligations at beginning of year	**$ 662**	$ 622
Liabilities incurred/acquired	**56**	57
Liabilities disposed	**(5)**	(13)
Liabilities settled	**(56)**	(51)
Accretion	**54**	47
Asset retirement obligations at December 31	**$ 711**	$ 662

At December 31, 2008, the estimated total undiscounted inflation-adjusted amount required to settle outstanding asset retirement obligations was $5.4 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 9.6%.

Except where indicated, all dollar amounts are in millions.

Note 12 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.

Details of the Company's commitments as at December 31, 2007 are disclosed in Note 15 of the consolidated financial statements in the Company's annual report for the year ended December 31, 2007. In 2008, the Company had additional contractual obligations to purchase goods and services totalling $3.3 billion. These contracts are expected to be settled in the following periods: 2009 - $1.3 billion; 2010 - $516 million; 2011 - $322 million; thereafter - $1.1 billion.

Note 13 Share Capital

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

Common Shares

Changes to issued common shares were as follows:

	Year ended December 31			
	2008		2007	
	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	848,960,310	$ 3,551	848,537,018	$ 3,533
Options exercised	394,500	17	423,292	18
Balance at December 31	**849,354,810**	**$ 3,568**	848,960,310	$ 3,551

Stock Options

In accordance with the Company's stock option plan, common share options may be granted to 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 terms of the original 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. Amendments to the Company's stock option plan in 2007 also provided for performance vesting of stock options. Performance options granted may vest in up to 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 that vest will depend upon the Company's performance measured over three calendar years. If the Company's performance is below the specified level compared with its industry peer group, the performance options awarded will be forfeited. If the Company's performance is at or above the specified level compared with its industry peer group, the number of performance options exercisable shall be determined by the Company's relative ranking.

Except where indicated, all dollar amounts are in millions.

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

	Year ended December 31			
	2008		2007	
	Number of Options *(thousands)*	Weighted Average Exercise Prices	Number of Options *(thousands)*	Weighted Average Exercise Prices
Outstanding, beginning of year	30,131	$ 37.18	11,656	$ 16.40
Granted	7,596	$ 41.18	26,926	$ 41.65
Exercised for common shares	(395)	$ 13.65	(423)	$ 11.84
Surrendered for cash	(4,132)	$ 22.50	(5,147)	$ 13.40
Forfeited	(2,373)	$ 41.58	(2,881)	$ 40.41
Outstanding at December 31	**30,827**	**$ 40.10**	30,131	$ 37.18
Options exercisable at December 31	**7,239**	**$ 35.95**	4,494	$ 14.09

	December 31, 2008				
	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
$11.67 - $11.99	1,138	$ 11.74	-	1,138	$ 11.74
$12.00 - $17.99	52	$ 15.46	1	52	$ 15.46
$18.00 - $27.99	224	$ 26.43	2	224	$ 26.43
$28.00 - $36.99	2,124	$ 32.40	4	314	$ 35.49
$37.00 - $39.99	833	$ 39.49	4	133	$ 38.20
$40.00 - $40.99	2,417	$ 40.88	4	285	$ 40.85
$41.00 - $45.02	24,039	$ 42.24	4	5,093	$ 41.68
	30,827	**$ 40.10**	**3**	**7,239**	**$ 35.95**

Except where indicated, all dollar amounts are in millions.

Note 14 Future Benefits

Total benefit costs recognized were as follows:

	Three months ended Dec. 31		Year ended Dec. 31	
	2008	2007	**2008**	2007
Employer current service cost	**$ 8**	$ 8	**$ 32**	$ 25
Interest cost	**3**	4	**13**	11
Expected return on plan assets	**(1)**	(3)	**(10)**	(10)
Amortization of net actuarial losses	**1**	-	**4**	4
	$ 11	$ 9	**$ 39**	$ 30

Note 15 Related Party Transactions

TransAlta Power, L.P. ("TAPLP") is under the indirect control of Husky's principal shareholders. TAPLP is a 49.99% owner in TransAlta Cogeneration, L.P. ("TACLP"), which is the Company's joint venture partner for the Meridian cogeneration facility at Lloydminster. The Company sells natural gas to the Meridian cogeneration facility and other cogeneration facilities owned by TACLP. These natural gas sales are related party transactions and have been measured at the exchange amount. For the year ended December 31, 2008, the total value of natural gas sales to the Meridian and other cogeneration facilities owned by TACLP was $125 million. At December 31, 2008, there were no accounts receivable related to these transactions.

Note 16 Financial Instruments and Risk Management

Details of the Company's significant accounting policies for the recognition and measurement of financial instruments and the basis for which income and expense are recognized are disclosed in Note 3 of the Company's 2007 consolidated financial statements.

Risk Management Overview

The Company is exposed to market risks related to the volatility of commodity prices, foreign exchange rates and interest rates. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

Fair Value of Financial Instruments

The Company's financial instruments as at December 31, 2008 included cash and cash equivalents, accounts receivable, contribution receivable, bank operating loans, accounts payable and accrued liabilities, contribution payable, long-term debt, the derivative portion of cash flow hedges and freestanding derivatives.

The carrying value of cash and cash equivalents, accounts receivable, bank operating loans, accounts payable and accrued liabilities approximates their fair value due to the short-term maturity of these investments.

At December 31, 2008, the carrying value of the contribution receivable and contribution payable was $1.5 billion and $1.7 billion respectively. The fair value of these financial instruments is not readily determinable due to uncertainties regarding timing of the cash flows. Refer to Note 6, "Joint Ventures."

The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability.

The fair value of long-term debt is the present value of future cash flows associated with the debt. Market information such as treasury rates and credit spreads is used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. The estimated fair value of long-term debt at the dates shown was:

	December 31, 2008		December 31, 2007	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt	**$ 1,957**	**$ 1,739**	$ 2,814	$ 2,903

Market Risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk and other price risk, for example, commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns.

In certain instances, the Company uses derivative commodity instruments to manage exposure to price volatility on a portion of its oil and gas production and firm commitments for the purchase or sale of crude oil and natural gas.

The Company's results will also be impacted by a decrease in the price of crude oil. The Company holds crude oil inventories that are feedstock or part of the in-process inventories at our refineries. These inventories are subject to a lower of cost or net realizable value test on a monthly basis and the Company is exposed to declining crude prices.

The Company's results are affected by the exchange rate between the Canadian and U.S. dollar. The majority of the Company's 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. 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. The majority of the Company's expenditures are in Canadian dollars.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related interest expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company has entered into cash flow hedges using cross currency debt swaps. In addition, a portion of our U.S. dollar denominated debt has been designated as a hedge of a net investment in a self-sustaining foreign operation and the unrealized foreign exchange gain is recorded in other comprehensive income.

To mitigate risk related to interest rates, the Company may enter into fair value hedges using interest rate swaps. The Company's objectives, processes and policies for managing market risk have not changed from the previous year.

Except where indicated, all dollar amounts are in millions.

Commodity Price Risk Management

Natural Gas Contracts

At December 31, 2008, the Company had the following third party offsetting physical purchase and sale natural gas contracts, which meet the definition of a derivative instrument:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	23,785	$ (2)
Physical sale contracts	(23,785)	$ 3

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

Natural Gas Storage Contracts

At December 31, 2008, the Company had the following third party physical purchase and sale natural gas contracts:

	Volumes *(mmcf)*	Fair Value
Physical purchase contracts	14,067	$ (7)
Physical sale contracts	(46,632)	$ 58

These contracts have been recorded at their fair value in accounts receivable and accrued liabilities and the resulting unrealized gain or loss has been recorded in revenue and cost of sales in the consolidated statement of earnings.

Interest Rate Risk Management

At December 31, 2008, the Company had a freestanding derivative that requires the payment of amounts based on a floating interest rate in exchange for receipt of payments based on a fixed interest rate with the following terms:

Notional Amount	Swap Maturity	Swap Rate *(percent)*	Fair Value
$ 200	July 14, 2009	CDOR + 175 bps	$ 4

This contract has been recorded at fair value in accounts receivable. Prior to August 29, 2008, this derivative was a hedging item in a fair value hedge and a gain of $3 million was recorded through interest expense. On August 29, 2008, the underlying debt was redeemed and the fair value hedge was discontinued. The gain of $1 million subsequent to August 29, 2008 has been recorded in other expenses.

Except where indicated, all dollar amounts are in millions.

Foreign Currency Risk Management

The Company manages its exposure to foreign exchange fluctuations by balancing the U.S. dollar denominated cash flows with U.S. dollar denominated borrowings and other financial instruments. Husky utilizes spot and forward sales to convert cash flows to or from U.S. or Canadian currency. At December 31, 2008, 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	$ 211	June 15, 2012	7.41	$ (44)
6.25% notes	U.S. $ 75	$ 89	June 15, 2012	5.65	$ 3
6.25% notes	U.S. $ 50	$ 59	June 15, 2012	5.67	$ 3
6.25% notes	U.S. $ 75	$ 88	June 15, 2012	5.61	$ 5

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 and the remaining loss has been included in other comprehensive income. As at December 31, 2008, the unrealized foreign exchange loss of $6 million (2007 - $14 million gain), net of tax of $2 million (2007 - $7 million) is recorded in other comprehensive income. At December 31, 2008, the balance in accumulated other comprehensive income was $10 million (2007 - $4 million), net of tax of $4 million (2007 - $2 million). For the year ended December 31, 2008, the Company recognized a foreign exchange gain of $83 million (2007 - loss of $62 million) on the cross currency debt swaps.

The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. dollars to Canadian dollars. During 2008, the impact of these contracts was a loss of $34 million (2007 - loss of $18 million) recorded in foreign exchange expense.

The Company entered into forward purchases of U.S. dollars. During the third quarter of 2008, the Company unwound one of the forward purchases realizing a gain of $12 million recorded in other expenses in the consolidated statement of earnings. At December 31, 2008, the following foreign exchange transactions were outstanding:

Date	Forward Purchases	Canadian Equivalent	Fair Value
October 5, 2007	U.S. $ 98	$ 97	$ 23
October 11, 2007	U.S. $ 98	$ 96	$ 23

These forward contracts have been recorded at fair value in accounts receivable and the resulting gain has been recorded in other expenses in the consolidated statement of earnings. During 2008, the impact was a gain of $38 million (2007 - $8 million gain).

Effective July 1, 2007, the Company’s U.S. $1.5 billion of debt financing related to the Lima acquisition was designated as a hedge of the Company’s net investment in the U.S. refining and marketing operations, which are considered self-sustaining. During the second quarter of 2008, the Company repaid its bridge financing of U.S. $750 million. In the last half of 2008, the Company repurchased U.S. $63 million of bonds that were classified as a net investment hedge. As a result, the Company’s net investment hedge is limited to the remaining U.S. $687 million. For the period ended December 31, 2008, the foreign exchange loss of $165 million (2007 - $102 million gain), net of tax of $27 million (2007 - $19 million), arising from the translation of the debt is recorded in other comprehensive income.

Sensitivity Analysis

A sensitivity analysis for foreign currency, commodities and interest rate risks has been calculated by increasing or decreasing the interest rate or foreign currency exchange rate, as appropriate, in the fair value methodologies described in the "Fair Value of Financial Instruments" section of this note. These sensitivities represent the effect resulting from changing the relevant rates with all other variables held constant and have been applied only to financial instruments. The Company's process for determining these sensitivities has not changed during the year. All calculations are on a pre-tax basis.

The Company is exposed to interest rate risk on its interest rate swaps. As at December 31, 2008, had interest rates been 50 basis points higher or lower and assuming all other variables remained constant, the impact to earnings before tax would have been less than $1 million.

The Company is exposed to interest rate and foreign currency risk on its cross currency debt swaps. As at December 31, 2008, had the Canadian dollar been 1% stronger versus the U.S. dollar and assuming all other variables remained constant, the impact to other comprehensive income would have been $4 million lower. Had the Canadian dollar been 1% weaker versus the U.S. dollar and assuming all other variables remained constant, the impact to other comprehensive income would have been $7 million higher. As at December 31, 2008, had the interest rates been 50 basis points higher and assuming all other variables remained constant, the impact to other comprehensive income would have been $2 million higher. Had the interest rates been 50 basis points lower and assuming all other variables remained constant, the impact to other comprehensive income would have been $7 million lower.

The Company is exposed to foreign currency risk on its forward purchases of U.S. dollars. As at December 31, 2008, had the Canadian dollar been 1% stronger relative to the U.S. dollar and assuming all other variables remained constant, the impact to earnings before tax would have been $2 million lower. Equal and offsetting impacts would have occurred had the Canadian dollar been 1% weaker relative to the U.S. dollar and assuming all other variables remained constant.

The Company is exposed to commodity price risk on its natural gas storage contracts. As at December 31, 2008, had the forward price been $0.20/mmbtu higher, the impact to earnings before tax would have been $7 million lower. Had the forward price been $0.20/mmbtu lower, then the impact to earnings before tax would have been $7 million higher.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual capital expenditure budgets which are monitored and are updated as required. In addition, the Company requires authorizations for expenditures on projects to assist with the management of capital.

Since the Company operates in the upstream oil and gas industry, it requires sufficient cash to fund capital programs necessary to maintain or increase production and develop reserves, to acquire strategic oil and gas assets, to repay maturing debt and to pay dividends. The Company's upstream capital programs are funded principally by cash provided from operating activities. During times of low oil and gas prices, a portion of capital programs can generally be deferred, however, due to the long cycle times and the importance to future cash flow in maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of long and short-term capital resources. Occasionally, the Company will hedge a portion of its production to protect cash flow in the event of commodity price declines. In addition, the Company has access to a revolving syndicated credit facility which allows the Company to borrow money from a group of banks on an unsecured basis.

Except where indicated, all dollar amounts are in millions.

The following are the contractual maturities of financial liabilities as at December 31, 2008:

Financial Liability	Less than 1 Year	1 to less than 2 Years	2 to less than 5 Years	Thereafter
Accounts payable and accrued liabilities	$ 2,896	$ -	$ -	$ -
Cross currency swaps	-	-	447	-
Long-term debt and interest on fixed rate debt	127	127	822	2,478
Total	$ 3,023	$ 127	$1,269	$ 2,478

The Company's contribution payable to the joint venture with BP (refer to Note 6) is payable between December 31, 2008 and December 31, 2015, with the final balance due and payable by December 31, 2015.

The Company's objectives, processes and policies for managing liquidity risk have not changed from the previous year.

Credit Risk

Credit risk represents the financial loss the Company would suffer if the Company's counterparties to a financial instrument, in owing an amount to the Company, fail to meet or discharge their obligation to the Company. The Company's accounts receivable are broad based with customers in the energy industry, midstream and end user segments and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial reassurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company did not have any customers that constituted more than 10% of total sales and operating revenues during the fourth quarter of 2008.

The Company's objectives, processes and policies for managing credit risk have not changed from the previous year.

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than 90 days. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits. The carrying amount of accounts receivable and cash and cash equivalents represents the maximum credit exposure.

The Company's accounts receivable excluding income taxes receivable and doubtful accounts was aged as follows:

Aging	**Dec. 31, 2008**
Current	**$ 1,145**
Past due (1 - 30 days)	**75**
Past due (31 - 60 days)	**17**
Past due (61 - 90 days)	**4**
Past due (more than 90 days)	**19**
Total	**$ 1,260**

Except where indicated, all dollar amounts are in millions.

The movement in the Company's allowance for doubtful accounts for 2008 was as follows:

Balance at January 1, 2008	$ 10
Provisions and revisions	12
Balance at December 31, 2008	**$ 22**

For 2008, the Company wrote off $3 million of uncollectible receivables.

Held-for-Trading Financial Liabilities

The Company's cross currency swaps have been designated as a cash flow hedge and the derivative component of the hedge meets the definition of a held-for-trading financial liability. The cross currency swap counterparties' credit profiles have not materially changed since the past year or since inception. As a result, the amount of change during the period and cumulatively in the fair value of the cross currency swaps has not been materially impacted by changes resulting from credit risk. At December 31, 2008, the amount the Company would be contractually required to pay under the cross currency swaps at maturity was $414 million higher (December 31, 2007 - $341 million higher) than their carrying amount.

Embedded Derivative

During the fourth quarter of 2008, a drilling contract previously treated as an embedded derivative no longer met the criteria and the related accounting treatment was discontinued. A loss of $42 million, after tax, was recorded in the fourth quarter compared with a gain of $9 million, after tax, in the fourth quarter of 2007. A loss of $71 million, after tax, was recorded in 2008 compared with a gain of $71 million, after tax, for the same period in 2007.

Note 17 Capital Disclosures

The Company's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of our underlying assets. The Company considers its capital structure to include shareholders' equity and debt. To maintain or adjust the capital structure, the Company may from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors capital based on the current and projected ratios of debt to cash flow from operations (defined as total debt divided by earnings from operations plus non-cash charges before settlement of asset retirement obligations and change in non-cash working capital) and debt to capital employed (defined as total debt divided by total debt and shareholders' equity). The Company's objective is to maintain a debt to cash flow from operations ratio of less than two times. At December 31, 2008, debt to cash flow from operations was 0.3 times. The ratio may increase at certain times as a result of acquisitions. To facilitate the management of this ratio, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however the bilateral credit facilities and the syndicated credit facility include a debt to cash flow covenant. The Company was fully compliant with this covenant at December 31, 2008.

There were no changes in the Company's approach to capital management from the previous year.

Husky Energy Inc. will host a conference call for analysts and investors on Thursday, February 5, 2009, at 4:15 p.m. Eastern time to discuss Husky's fourth 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.com under Investor Relations. The webcast will be archived for approximately 90 days.

Media are invited to listen to the conference call.

- Dial 1-800-597-1419 beginning at 4:05 p.m. (Eastern time)

A recording of the call will be available at approximately 5:30 p.m. (Eastern time)

- Dial 1-800-319-6413 (dial reservation # 2658)

The Postview will be available until March 4, 2009.

- 30 -

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