press release

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Delphi Energy Corp.

DELPHI ENERGY INCREASES PRODUCTION, FUNDS FLOW, RESERVES IN 2006

CALGARY, ALBERTA – March 8, 2007 – Delphi Energy Corp. is pleased to announce its financial and operational results for the year ended December 31, 2006.

2006 Highlights

- Increased average production by 24 percent to 5,228 barrels of oil equivalent per day (boe/d), primarily as a result of successful drilling at Bigstone in North West Alberta and Bigfoot in North East British Columbia.
- Increased funds from operations by 23 percent to $49.6 million ($0.85 per basic share) compared to $40.2 million ($0.80 per basic share) in 2005. Fourth quarter funds from operations totaled $11.8 million ($0.19 per basic share).
- Achieved net earnings of $6.9 million ($0.12 per share) in 2006 compared to $6.7 million ($0.13 per share) for 2005.
- Added 7.4 million boe (5.8 million net of revisions) of proved plus probable reserves in 2006.
- Increased undeveloped land by 66 percent to 86,062 net acres.
- Increased proved and probable reserves by 20 percent to 17.3 million boe.
- Reduced operating costs to $8.29 per boe from $8.46 in 2005 despite a high inflationary environment for oilfield services throughout the year.
- Drilled 52.0 (21.7 net) wells in 2006 resulting in an 85 percent (90 percent net) success rate.
- Achieved hedging gains of $10.5 million through the Company's risk management program, increasing the Company's average realized natural gas price by $1.12 per thousand cubic feet, 17 percent higher than the benchmark AECO price in 2006.

Operational Highlights

	Three Months Ended December 31			Year Ended December 31		
Production	**2006**	2005	% Change	**2006**	2005	% Change
Natural gas (mcf/d)	**24,919**	22,909	9	**25,706**	19,848	30
Crude oil (bbls/d)	**388**	573	(32)	**476**	614	(22)
Natural gas liquids (bbls/d)	**441**	455	(3)	**468**	299	57
Total (boe/d)	**4,982**	4,846	3	**5,228**	4,221	24

Company Interest Reserves [1]	Year Ended December 31 2006	2005	% Change
Natural gas (mmcf)			
Proved	**58,554**	50,660	16
Probable	**26,562**	18,421	44
Proved plus probable	**85,116**	69,081	23
Crude oil and NGL (mbbls)			
Proved	**1,630**	1,977	(18)
Probable	**1,495**	934	60
Proved plus probable	**3,125**	2,911	7
Total reserves (mboe)			
Proved	**11,389**	10,420	9
Probable	**5,922**	4,004	48
Proved plus probable	**17,311**	14,424	20

(1) Gross reserves represent the Company's interest including royalty interests before the deduction of royalties.

Financial Highlights ($000s except per boe and per share amounts)

	Three Months Ended December 31			Year Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Petroleum and natural gas sales	**22,928**	28,961	(21)	**94,189**	80,880	16
Per boe	**50.02**	64.94	(23)	**49.36**	52.48	(6)
Funds from operations	**11,817**	16,118	(27)	**49,551**	40,212	23
Per boe	**25.78**	36.14	(29)	**25.97**	26.09	-
Per share – Basic	**0.19**	0.31	(39)	**0.85**	0.80	6
Per share – Diluted	**0.19**	0.31	(39)	**0.84**	0.79	6
Net earnings	**290**	6,425	(95)	**6,903**	6,677	3
Per boe	**0.62**	14.40	(96)	**3.62**	4.32	(16)
Per share – Basic	**-**	0.13	(100)	**0.12**	0.13	(8)
Per share – Diluted	**-**	0.12	(100)	**0.12**	0.13	(8)
Capital invested	**12,124**	29,056	(58)	**165,352**	112,468	47
Proceeds on dispositions	**(17,867)**	-	-	**(34,918)**	(5,862)	496
Net capital	**(5,743)**	29,056	-	**130,434**	106,606	22
Debt plus working capital deficit				**118,178**	61,020	94
Total assets				**326,668**	244,666	34
Shares outstanding						
Basic				**60,663**	55,254	10
Diluted				**64,892**	57,883	12

MESSAGE TO SHAREHOLDERS

During 2006, Delphi's average production increased 24 percent to 5,228 barrels of oil equivalent per day, proved plus probable reserves increased 20 percent to 17.3 million barrels of oil equivalent, funds flow increased 23 percent to $49.6 million and net earnings increased three percent to $6.9 million.

Our growth resulted from continued success through the drill bit. Delphi spent $165 million to drill 52 wells (21.7 net) in 2006 with a 90 percent success rate. All but four of these wells were drilled during the first four months of the year. This compares favourably with the 45 wells (22.6 net) drilled in 2005, but is much lower than the 72 wells expected to be drilled during the year.

Successful drilling at Bigstone in North West Alberta and Bigfoot in North East British Columbia helped increase the Company's production, reserves, funds flow and net earnings over the past year and establish a solid foundation for the future. In addition, significant capital was deployed during 2006 constructing one-time gas gathering infrastructure in both of these areas in preparation for future development drilling.

Although the pace of growth in 2006 fell short of expectations, the results best represent a mid-mountain plateau rather than the summit in our long term growth strategy. At Bigfoot, a successful winter drilling program was over-shadowed by significantly higher than anticipated costs, primarily for the infrastructure, resulting in fewer wells drilled at Bigfoot and limiting our financial flexibility to spend capital elsewhere throughout the remainder of 2006. In addition, the initial flush production from several wells successfully drilled late in 2005 experienced higher than expected decline rates during the first half of the year. Although decline profiles from these wells continue to moderate to a more typical 12 percent to 15 percent per year, the subsequent production shortfall was not replaced due to a significantly curtailed capital program during the second half of the year, drilling only four of 17 wells planned. The combination of these factors contributed to lower than anticipated production and funds flow, increased concern regarding the Company's debt levels and discontent in the market, resulting in a growing gap between the Company's strong fundamentals and a weak share price.

In addition to the Company's growth through the drill bit, Delphi has successfully employed an acquisition strategy that has included the $57 million acquisition of a private company at the end of 2004, the $52 million acquisition of 24,000 acres of natural gas properties at Bigstone at the beginning of 2005 and the opportunity available at Bigfoot at the end of 2005 earned through the significant capital program in 2006.

These successful growth initiatives have been financed through a combination of funds flow from operations, new equity, non-core asset dispositions, and incremental bank debt. The quality of the producing assets offer a high netback funds flow stream as well as a reliable borrowing base. A strategic commodity hedging program protects the funds flow stream from commodity price volatility. Delphi has approximately 55 percent of its natural gas production hedged at a minimum price of almost $9.00 per mcf through to March 2008. This compares favourably to both the 2006 AECO average price of $6.55 per mcf and the 2005 AECO average price of $8.81 per mcf.

Over the past four years through the many successes and only a few disappointments around the above growth initiatives, the debt to funds flow ratio has fluctuated from a high of 3.0 in the first quarter of 2005 to a low of 1.0 at the end of 2005, increasing again to a current ratio of 2.4 at the end of 2006. The Company has set its growth plans incorporating a desired downward trending debt to funds flow ratio of 1.7 at the end of 2007 and back to 1.0 by the end of 2008. The Company will continue to use leverage respectfully, balancing the cost of capital and risk to facilitate, not limit, our growth.

Operational Review

Average production for the year of 5,228 boe/d represents a 24 percent increase over the 4,221 boe/d produced in 2005. Natural gas and NGL production volumes accounted for 91 percent of Delphi's production in 2006 compared with 85 percent in 2005.

During the year, the Company drilled a total of 52 (21.7 net) wells, with a success rate of 90 percent. The 2006 drilling program resulted in 19.0 net natural gas wells, 0.6 net oil wells and 2.1 net dry holes. The Company pursued only a limited drilling program in the second half of 2006. The successful 2006 development and exploration drilling program resulted in significant reserves growth for the Company. Proved natural gas reserves increased 16 percent with net additions of 17.3 billion cubic feet (bcf) and proved plus probable natural gas reserves increased 23 percent with net additions of 25.4 bcf. Total additions on a proved reserves basis were 2.9 million boe and total additions on a proved plus probable reserves basis were 4.8 million boe. Total proved reserves increased 9 percent to 11.4 million boe and proved plus probable reserves increased 20 percent to 17.3 million boe. The reserve additions for the year resulted in a reserve replacement ratio of 2.5 times 2006 production of 1.9 million boe.

Finding and development costs for 2006 on a proved plus probable basis were $32.04 per boe, including future development capital. This compares with our three-year average finding and development costs of $21.46 per boe on the same basis. At Bigfoot, Delphi contributed 90 percent of the capital to earn a 50 percent working interest in the property, spending $91.4 million, of which 40 percent was spent on major one-time infrastructure and seismic rather than on drilling activities that have an immediate production, funds flow and reserves impact. Finding and development costs in 2006 for Delphi at Bigfoot were approximately $25.40 per boe, after giving effect to the earning terms. This compares to approximately $14.00 per boe on a gross basis which better represents expected efficiencies on a go-forward basis.

Financial Review

Funds from operations for 2006 were $49.6 million ($0.85 per share), an increase of 23 percent over the prior year. Delphi achieved this funds flow through a combination of higher than benchmark realized natural gas prices resulting from its strategic risk management program, an improved cost structure and increased production compared to the previous year. The risk management program resulted in hedging gains of $10.5 million increasing the Company's average realized natural gas price by $1.12 per mcf, 17 percent higher than the benchmark AECO price in 2006. Operating costs per boe were reduced to $8.29 per boe from $8.46 in 2005 despite a high inflationary environment for oilfield services throughout most of the year. Cash netbacks were virtually unchanged at $25.97 per boe compared to $26.09 per boe from the previous year. Net earnings for the year were $6.9 million ($0.12 per share) compared to $6.7 million ($0.13 per share) in 2005.

In 2006, Delphi incurred record total capital expenditures of $165.4 million, with 55 percent of the capital being incurred at Bigfoot in North East British Columbia to satisfy its obligation to earn a 50 percent working interest in 19 wells, non-recurring infrastructure costs and 118 sections of land. The majority of the remaining capital was incurred at Bigstone, Alberta through the drilling of 6 gross (4.2 net) wells and expansion of the Company's infrastructure in the area to provide for development of the west block of the Company's lands in the area. The capital program was financed through proceeds on disposition of non-core low working interest properties, funds from operations, issuance of flow-through common shares and utilization of the Company's credit facilities with its lenders.

Outlook

The successes, challenges, and business environment of 2006 sets the stage for measured growth expectations in 2007. The Company continues to plan and execute its capital spending within near term funds flow expectations as a result of the uncertain and volatile natural gas price environment. Delphi maintains the view that natural gas supply and demand fundamentals will gradually improve during 2007 providing greater clarity and upside to natural gas prices into 2008. The Company expects to spend a greater portion of its capital program during the second half of 2007 providing significant growth potential into 2008 as the capital program further unlocks the undeveloped value in Bigstone, Bigfoot and other core assets. Natural gas price clarity and moderating equipment and service costs are catalysts to a more sustainable growth environment. For Delphi, with one-time infrastructure capital completed, these catalysts are only a bonus, as future capital efficiencies are already forecast to improve significantly with a much greater percentage of the capital focused on drilling.

Delphi expects to spend its estimated funds flow of $45 to $50 million in 2007 to increase its average production to between 5,200 to 5,400 boe/d and exit the year producing approximately 5,700 boe/d. Current production is estimated to be 4,500 boe/d. Approximately 60 percent of Delphi's proved non-producing reserves are expected to be on production in the second quarter of 2007, including our exploration discovery at Tower Creek, Alberta. Initial production rates at Tower Creek are projected to be approximately 500 to 600 boe/d net to Delphi and the Company expects to drill a second exploration test in the area after spring break-up. Additional production volumes are expected to come on stream early in the second quarter as the winter drilling program concludes.

Delphi continues to trade at a significant discount to its net asset value per share estimated to be $3.26 (discounted eight percent before tax) based on our December 31, 2006 reserves as evaluated by GLJ Petroleum Consultants Ltd. and reflects only a portion of the undeveloped growth potential and value within the Company. The Company is committed to regaining market confidence through a successful 2007 capital program delivering on and exceeding growth expectations.

Delphi has a significant inventory of defined and repeatable prospects. The Company has the producing assets, prospects and financial resources to deliver long-term organic growth. Delphi continues to add to its inventory of opportunities through strategic industry relationships. Thanks to these distinguishing characteristics and a talented team, I believe the Company will quickly return to its track record of 20 percent to 25 percent annual growth. I would like to express my gratitude to our loyal shareholders for looking past short-term natural gas price pressures, operational challenges and stock market fluctuations in order to keep an eye on the big picture. I'm confident this patience will be rewarded.

Management's Discussion and Analysis

(all tabular amounts are expressed in thousands of CDN dollars, except per unit amounts)

The following discussion and analysis has been prepared by management and reviewed and approved by the Board of Directors of Delphi Energy Corp ("Delphi" or "the Company"). The discussion and analysis is a review of the financial results of the Company based upon accounting principles generally accepted in Canada. Its focus is primarily a comparison of the financial performance for the three and 12 months ended December 31, 2006 and 2005 and should be read in conjunction with the audited financial statements and accompanying notes for the year ended December 31, 2006. The discussion and analysis has been prepared as of March 6, 2007.

Basis of Presentation*. For the purpose of reporting production information, reserves and calculating unit prices and costs, natural gas volumes have been converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with the Canadian Securities Administrators' National Instrument 51-101 when boes are disclosed. Boes may be misleading, particularly if used in isolation.*

NON GAAP Measures*. The MD&A contains the terms "funds from operations", "funds from operations per share" and "netbacks" which are not recognized measures under Canadian generally accepted accounting principles. The Company uses these measures to help evaluate its performance. Management considers netbacks an important measure as it demonstrates its profitability relative to current commodity prices. Management uses funds from operations to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. Funds from operations has been defined by the Company as net earnings plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized (gain)/loss on risk management activities) and excludes the change in non-cash working capital related to operating activities and expenditures on asset retirement obligations and reclamation. The Company also presents funds from operations per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share. Delphi's determination of funds from operations may not be comparable to that reported by other companies nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.*

Forward-Looking Statements*. Certain information regarding Delphi Energy Corp. set forth in this document, including management's assessment of the Company's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Company's control, including the effects of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other oil and gas companies, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from both internal and external sources. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur.*

Production

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas (mcf/d)	**24,919**	22,909	9	**25,706**	19,848	30
Crude oil (bbl/d)	**388**	573	(32)	**476**	614	(22)
Natural gas liquids (bbl/d)	**441**	455	(3)	**468**	299	57
Total (boe/d)	**4,982**	4,846	3	**5,228**	4,221	24

Production for the 12 months ended December 31, 2006 averaged 5,228 boe/d representing an increase of 24 percent over the comparative period primarily due to successful drilling programs at Bigstone, Alberta ("Bigstone") and in the Bigfoot area of North East British Columbia ("Bigfoot"). Although Delphi was successful with the drill bit in 2006, production was less than anticipated due to higher than expected declines on wells drilled in Bigstone at the end of 2005, minimal capital directed towards drilling activities in the second half of 2006, numerous facility interruptions throughout the year, and processing constraints at certain properties. The Company's production portfolio for the year was weighted 82 percent to natural gas, nine percent to crude oil and nine percent to natural gas liquids. Production for the three months ended December 31, 2006 ("the Quarter") decreased two percent from the third quarter due to natural declines and the sale of approximately 250 boe/d at the end of November 2006. The Company estimates there are approximately 900 boe/d behind pipe awaiting tie-in which is expected to occur in the first and second quarters of 2007 with the majority of behind pipe volumes being related to the Company's exploration discovery at Tower Creek. Delphi is expecting production for 2007 to average 5,200 boe/d to 5,400 boe/d with an exit rate of approximately 5,700 boe/d.

Crude oil production was 32 percent and 22 percent lower as compared to the comparative periods in 2005 due to the sale of approximately 50 boe/d, natural declines and minimal capital investment towards adding new production.

Natural gas liquids (NGL) production, primarily condensate, has increased significantly as a result of the high yield of liquids associated with increased natural gas production at Bigstone.

Commodity Prices and Risk Management

Benchmark Prices

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas						
NYMEX (US $/mmbtu)	**6.65**	12.36	(46)	**6.75**	8.89	(24)
AECO (CDN $/mcf)	**6.90**	11.61	(41)	**6.55**	8.81	(26)
Crude oil						
West Texas Intermediate (US $/bbl)	**59.95**	60.05	-	**66.00**	56.70	16
Edmonton Light (CDN $/bbl)	**65.45**	72.11	(9)	**72.90**	69.82	4
Foreign exchange rate						
Canadian to US dollar	**1.14**	1.17	(3)	**1.13**	1.21	(7)
US to Canadian dollar	**0.88**	0.85	3	**0.88**	0.83	6

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub in Louisiana (NYMEX) while Canadian natural gas prices are typically referenced to the AECO Hub in Alberta. Natural gas prices are influenced more by North American supply and demand than global fundamentals. In 2006, it was a challenging year for natural gas prices as a warm winter early in the year followed by a relatively cool summer failed to eradicate the record amount of natural gas inventory in storage resulting in a sharp decrease in the price of natural gas. During the year, the AECO average daily spot price ranged from a high of $8.60 per thousand cubic feet to a low of $4.69 per thousand cubic feet. Delphi expects prices to remain volatile throughout 2007 and as such, has extended its price protection strategy to protect the Company's capital program and its balance sheet. Currently, Delphi has hedged approximately 55 percent of its before-royalty gas production at an average AECO floor price of $8.96 per thousand cubic feet from January 1, 2007 to March 31, 2008. Delphi believes the long term supply and demand fundamentals for natural gas will support stronger, less volatile prices in the future.

Crude Oil

West Texas Intermediate at Cushing, Oklahoma (WTI) is the benchmark reference for North American crude oil prices. Canadian crude oil prices are based upon postings, primarily at Edmonton, Alberta, and represent the WTI price adjusted for quality and transportation differentials as well as the US/CDN dollar exchange rate. In contrast to natural gas prices, 2006 was an excellent year for crude oil prices which continued to show sustained strength due to several major production disruptions, geopolitical unrest in major oil producing countries in the Middle East and Africa and strong global demand.

The prices received for crude oil are related to the price of crude oil in world markets. Prices for heavy oil and other lesser quality crudes trade at a discount or differential to light crude oil due to the additional costs in the refining process. The differential narrowed in 2006 averaging $21.70 per barrel compared to $24.17 per barrel in 2005. The narrowing of the differential was the primary driver of a 14 percent increase in Bow River crude prices, a benchmark for medium grade oil prices.

Risk Management Activities

Delphi enters into both financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations designed to ensure sufficient cash is generated to fund its capital program particularly when commodity prices are extremely volatile.

The Company has chosen to mark-to-market its financial commodity contracts and record any unrealized gain or loss. The estimated fair value of unrealized derivative instruments is reported on the balance sheet with any change in the unrealized positions charged to earnings. The Company recognized an unrealized non-cash gain on risk management activities for the year ended December 31, 2006 of $1.0 million related to financial commodity contracts. During the year ended December 31, 2006, Delphi recorded a realized loss on financial commodity contracts of $0.2 million. The estimated fair value of Delphi's physical and financial contracts at December 31, 2006 was approximately $8.9 and $0.3 million respectively. The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period with reference to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, actual amounts realized may differ from these estimates.

The Company has fixed the price applicable to future production through the following contracts:

Time Period	Commodity	Type of Contract	Quantity Contracted	Canadian Price (CDN$/unit)
November 2006 – March 2007	Natural Gas	Physical	2,000 GJ/d	$10.00 fixed
November 2006 – March 2007	Natural Gas	Physical	4,000 GJ/d	$9.50 floor/$10.65 ceiling
November 2006 – March 2007	Natural Gas	Physical	2,000 GJ/d	$9.50 floor/$11.35 ceiling
November 2006 – March 2007	Natural Gas	Physical	4,000 GJ/d	$8.75 floor/$10.00 ceiling
November 2006 – March 2007	Natural Gas	Physical	2,000 mmbtu/d	$11.05 floor/$12.92 ceiling
January 2007 – March 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$10.45 ceiling
April 2007 – October 2007	Natural Gas	Physical	3,000 GJ/d	$8.75 floor/$9.55 ceiling
April 2007 – October 2007	Natural Gas	Physical	4,000 GJ/d	$8.00 floor/$8.92 ceiling
April 2007 – October 2007	Natural Gas	Physical	2,000 mmbtu/d	$8.94 fixed
April 2007 – October 2007	Natural Gas	Physical	2,000 GJ/d	$6.50 floor/$8.15 ceiling
April 2007 – October 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$9.00 ceiling
November 2007 – December 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$10.45 ceiling
November 2007 – March 2008	Natural Gas	Physical	3,000 GJ/d	$9.00 floor/$9.98 ceiling
November 2007 – March 2008	Natural Gas	Physical	2,000 mmbtu/d	$11.07 fixed
November 2007 – March 2008	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$9.03 ceiling
November 2007 – March 2008 (1)	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$10.02 ceiling
April 2008 – October 2008	Natural Gas	Physical	4,000 GJ/d	$7.21 fixed

(1) Entered into subsequent to year-end.

The contract prices on physical contracts are recognized in earnings in the same period as the production revenue.

Realized Sales Prices

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas ($/mcf)	**8.41**	12.17	(31)	**8.05**	9.37	(14)
Gain/(loss) on financial contracts ($/mcf)	**-**	(0.48)	-	**(0.02)**	(0.17)	(88)
Realized gas price ($/mcf)	**8.41**	11.69	(28)	**8.03**	9.20	(13)
Crude oil ($/bbl)	**47.09**	43.49	8	**53.19**	45.48	17
Loss on financial contracts ($/bbl)	**-**	(7.85)	-	**-**	(7.10)	-
Realized oil price ($/bbl)	**47.09**	35.64	32	**53.19**	38.38	39
Natural gas liquids ($/bbl)	**48.55**	58.35	(17)	**56.25**	51.82	9
Total realized sales price ($/boe)	**50.02**	64.94	(23)	**49.36**	52.48	(6)

The decrease in the average natural gas price received by Delphi during the three and 12 months ended December 31, 2006, is consistent with the significant decrease in the AECO spot price. The Company continues to receive higher than the AECO spot price on natural gas sales due to the high heating content of natural gas production and the sale of approximately 19 percent of the Company's production being priced at Chicago from sales on the Alliance Pipeline for the three and 12 months ended December 31, 2006. During the three and 12 months ended December 31, 2006, Delphi benefited from its risk management program in which the Company fixed the price on a portion of its natural gas production at amounts significantly higher than the AECO spot price. The risk management program increased the average natural gas price received during the Quarter by approximately $1.30 per mcf and $1.12 per mcf for the year. The increase in the average oil price received by Delphi during the 12 months ended December 31, 2006, is consistent with the upward trend of the benchmark WTI and the narrowing of the quality differential, offset by the strengthening of the Canadian dollar. Delphi's oil production is predominantly a medium grade oil therefore the Company's average price fluctuates with the quality differential. During the Quarter, Delphi's realized oil price increased due to higher production from Delphi's light oil discovery at Bigstone. Realized natural gas liquids prices have increased due to the increase in the price received for condensate, the primary component of the Company's natural gas liquids production.

Revenue

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas	**19,277**	25,652	(25)	**75,523**	67,898	11
Crude oil	**1,681**	2,293	(27)	**9,242**	10,209	(9)
Natural gas liquids	**1,970**	2,447	(20)	**9,609**	5,657	70
Realized loss on financial contracts	**-**	(1,431)	(100)	**(185)**	(2,884)	(94)
Total	**22,928**	28,961	(21)	**94,189**	80,880	16

The increase in revenue for the 12 months ended December 31, 2006, over the comparative period is attributable to increased production volumes offset by a decrease in the realized price received due to lower natural gas prices. Revenue for the 12 months ended December 31, 2006 increased 16 percent over the comparative period due to a 24 percent increase in production volumes offset by a six percent decrease in the realized price received. Revenue during the Quarter decreased 21 percent over the comparative period due to a 23 percent decrease in the average price received offset by a 3 percent increase in production volumes.

Royalties

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Crown	**3,909**	6,929	(44)	**16,915**	17,314	(2)
Freehold and gross overriding	**203**	247	(18)	**908**	1,131	(20)
Total	**4,112**	7,176	(43)	**17,823**	18,445	(3)
Royalty credits	**(1,302)**	(630)	107	**(4,092)**	(2,110)	94
Net	**2,810**	6,546	(57)	**13,731**	16,335	(16)
Per boe	**6.13**	14.68	(58)	**7.20**	10.60	(32)
Percent of total revenue	**12.3**	22.6		**14.6**	20.2	

The Company pays royalties to provincial governments (Crown), freeholders, which can be individuals or companies, and other oil and gas operators, who own surface or mineral rights. Crown royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price fluctuations or changes in production volumes on a well by well basis subject to a minimum and maximum rate restriction ascribed by the Crown. During the three and 12 months ended December 31, 2006, royalties as a percentage of revenue decreased to 12.3 percent and 14.6 percent due to Delphi realizing approximately $3.5 million and $10.5 million in hedging gains, included in revenue, but on which royalties are not paid. In Alberta, Delphi pays royalties based on the provincial reference price not the prices received resulting in Delphi not paying royalties on the incremental $10.5 million in hedging gains. Delphi is expecting royalties as a percentage of revenue before hedging to be between 17 – 20 percent in 2007.

Royalty credits for the three and 12 month period ended December 31, 2006 are higher than the comparative periods due to capital being spent on natural gas infrastructure which has resulted in an increase in the Gas Cost Allowance (GCA) credit. The GCA is a deduction from Alberta Crown royalties to compensate the Company for the cost of gathering, processing and compression facilities to process the Crown royalty portion of production. The Company receives the Alberta Royalty Tax Credit (ARTC), a tax rebate from the Alberta government for eligible crown royalties paid in the year subject to a maximum of $0.5 million in 2006. The Alberta government recently announced that the ARTC tax rebate program will be cancelled and as such, Delphi will not receive the rebate in 2007 and forward.

Operating Expenses

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Total	**3,859**	3,523	10	**15,826**	13,041	21
Per boe	**8.42**	7.90	7	**8.29**	8.46	(2)

Operating expenses on a per boe basis for the 12 months ended December 31, 2006, decreased two percent over the comparative period despite an environment which faced strong inflationary pressures. Despite the decrease in natural gas prices in 2006, the industry still experienced increased costs for services, supplies, materials, electricity and labour. Operating costs during the Quarter decreased 4 percent from the third quarter of 2006 and increased 7 percent over the comparative period in 2005.

Transportation Expenses

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Total	**1,627**	1,418	15	**6,455**	4,893	32
Per boe	**3.55**	3.18	12	**3.38**	3.18	6

In British Columbia, infrastructure is owned by Duke Energy that enables natural gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

On a per boe basis, transportation costs for the three and 12 months ended December 31, 2006 increased over the comparative periods due to production from the Bigfoot area being brought on-stream in the second quarter of 2006. For the three and 12 months ended December 31, 2006, approximately 25 – 30 percent of the Company's natural gas production from the Bigstone area was shipped on the Alliance Pipeline and sold in Chicago. The costs of transmission from the field to Chicago are included in transportation expenses. The volumes shipped on the Alliance Pipeline have higher than the corporate average transportation costs; however, these costs are partially offset by the higher price received at Chicago.

General and Administrative

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
General and administrative costs	**1,339**	1,252	7	**5,498**	4,666	18
Overhead recoveries	**(137)**	(434)	(68)	**(1,081)**	(869)	24
Salary allocations	**(413)**	(395)	5	**(2,045)**	(1,306)	57
Net	**789**	423	87	**2,372**	2,491	(5)
Per boe	**1.72**	0.95	81	**1.24**	1.62	(23)

On a per boe basis, general and administrative (G&A) costs for the 12 months ended December 31, 2006 decreased 23 percent from the comparative period in 2005. The decrease in G&A is due to an increase in production with minimal amount of increased personnel costs. During the Quarter, G&A per boe increased 60 percent from the third quarter due to decreased overhead recoveries as capital spending was limited during the Quarter, lower production volumes and overall higher corporate costs, primarily office rent. On a gross basis, G&A for the three and 12 months ended December 31, 2006 has increased seven and 18 percent respectively, commensurate with increased staffing and activity levels. As a result of unprecedented levels of activity for Delphi and for the industry as a whole, the costs associated with hiring, compensating, and retaining employees and consultants have risen.

For the three and 12 months ended December 31, 2006, salary allocations have increased by 5 percent and 57 percent due to increased technical staff efforts toward the Company's exploration and development program. Overhead recoveries have increased over the prior year due to higher capital spending.

Stock-based Compensation

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Total	**317**	382	(17)	**2,491**	1,631	53
Per boe	**0.69**	0.86	(20)	**1.31**	1.06	23

Stock-based compensation expense is the amortization over the vesting period of the fair value of stock options granted to employees, directors and key consultants of the Company. The fair value of all options granted is estimated at the date of grant using the Black-Scholes option pricing model. The non-cash compensation expense for the 12 months ended December 31, 2006, increased 53 percent due to options being granted to staff to facilitate the growth of the Company and to retain current staff in today's competitive environment. Delphi believes providing an employee with stock options is an effective way to align the employees' goals with the shareholders and retain key employees. Pursuant to Delphi's option plan, one-third of the options granted vest immediately resulting in higher initial compensation expense. During the three and 12 months ended December 31, 2006, Delphi capitalized $0.3 and $0.9 million of stock based compensation associated with exploration and development activities.

Interest

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Total	**2,026**	883	129	**6,254**	3,658	71
Per boe	**4.42**	1.98	123	**3.28**	2.37	38

Interest expense on a per boe basis increased 123 percent and 38 percent over the comparable periods due to higher bank debt from increased capital spending and higher average interest rates. Interest expense on a gross and per boe basis increased from the third quarter due to higher debt balances and interest rates along with lower production volumes.

Depletion, Depreciation and Accretion

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Depletion and depreciation	**11,090**	8,329	33	**39,727**	26,568	50
Accretion expense	**173**	166	4	**637**	526	21
Total	**11,263**	8,495	33	**40,364**	27,094	49
Per boe	**24.58**	19.05	29	**21.15**	17.59	20

Depletion, depreciation, and accretion per boe increased 29 percent and 20 percent, respectively, for the three and 12 months ended December 31, 2006. This increase is attributable to higher cost proved reserve additions through drilling and acquisitions, which is a trend throughout the industry. Throughout 2006, Delphi invested a significant amount of capital towards field infrastructure, allocated to depletable costs on a reasonable basis, which does not immediately increase proved reserves but is critical to current operations and future development plans. The higher depletion and depreciation is indicative of the reality that the Western Canadian Sedimentary Basin is one of the most expensive basins in the world to add proved reserves. The increase in total depletion and depreciation versus the comparative periods is a result of increased production levels and a higher per boe rate.

Accretion expense of asset retirement obligations relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which meets or exceeds environmental standards. Due to the long term nature of certain assets of the Company, this accretion expense is estimated to extend over a term of three to 20 years. The Company uses a credit adjusted risk-free rate of eight percent for the purpose of calculating the fair value of its asset retirement obligations and hence the accretion expense. The accretion expense for the three and 12 months ended December 31, 2006 increased four and 21 percent over the comparative periods. The increase is due to an extensive drilling program in 2006.

Taxes

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Capital	**-**	49	(100)	**-**	250	(100)
Future	**295**	3,464	(91)	**786**	4,165	(81)
Total	**295**	3,513	(92)	**786**	4,415	(82)

The provision for future income taxes for the three and 12 months ended December 31, 2006 were $0.3 million and $0.8 million resulting in an effective tax rate of 50 and ten percent. The 12 months ended December 31, 2006 includes a recovery of $3.0 million relating to a reduction in future federal and provincial income tax rates enacted during the second quarter. The Company did not record any capital taxes in 2006 as capital taxes were eliminated effective January 1st, 2006 pursuant to the Federal Government budget of May 2nd, 2006. Delphi does not anticipate it will be cash taxable until 2008 or later based on current commodity prices.

Funds from Operations

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Net earnings	**290**	6,425	(95)	**6,903**	6,677	3
Non-cash items						
Depletion, depreciation and accretion	**11,263**	8,495	33	**40,364**	27,094	49
Unrealized loss/(gain) on risk management activities	**(348)**	(2,648)	(87)	**(993)**	645	(254)
Stock-based compensation expense	**317**	382	(17)	**2,491**	1,631	53
Future income taxes	**295**	3,464	(91)	**786**	4,165	(81)
Funds from operations	**11,817**	16,118	(27)	**49,551**	40,212	23

For the three and 12 months ended December 31, 2006 funds from operations were $11.8 million ($0.19 per basic share) and $49.6 million ($0.85 per basic share) compared to $16.1 million (2005 - $0.31 per basic share) and $40.2 million (2005 - $0.80 per basic share).

Net Earnings

For the three and 12 months ended December 31, 2006, Delphi recorded net earnings of $0.3 million and $6.9 million. Earnings were adversely affected by non-cash items such as depletion, depreciation, accretion, stock-based compensation and future income taxes.

Netback Analysis

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**50.02**	64.94	(23)	**49.36**	52.48	(6)
Royalties, net of ARTC	**6.13**	14.68	(58)	**7.20**	10.60	(32)
Operating expenses	**8.42**	7.90	7	**8.29**	8.46	(2)
Transportation	**3.55**	3.18	12	**3.38**	3.18	6
Operating netback	**31.92**	39.18	(19)	**30.49**	30.24	1
G&A	**1.72**	0.95	81	**1.24**	1.62	(23)
Interest	**4.42**	1.98	123	**3.28**	2.37	38
Current taxes	**-**	0.11	(100)	**-**	0.16	(100)
Cash netback	**25.78**	36.14	(29)	**25.97**	26.09	(0)
Unrealized (gain)/loss on financial contracts	**(0.76)**	(5.94)	(87)	**(0.52)**	0.42	(224)
Stock-based compensation expense	**0.69**	0.86	(20)	**1.31**	1.06	23
Depletion, depreciation and accretion	**24.58**	19.05	29	**21.15**	17.59	20
Future income taxes (recovery)	**0.64**	7.77	(92)	**0.41**	2.70	(85)
Net earnings (loss)	**0.62**	14.40	(96)	**3.62**	4.32	(16)

Approximately 82 percent of Delphi's production is natural gas and therefore Delphi's netbacks are primarily driven by the price received for natural gas. Delphi has an active risk management program to mitigate some of the volatility in commodity prices. During the Quarter cash netbacks increased ten percent from the third quarter of 2006 due to increased operating netbacks per boe (increased $3.83/boe or 13 percent) offset by an increase in G&A per boe ($0.65/boe or 60 percent) and interest per boe ($0.68/boe or 18 percent).

Drilling Results

	Three Months Ended December 31		Twelve Months Ended December 31	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**-**	-	**43.0**	**19.0**
Oil wells	**-**	-	**1.0**	**0.6**
Dry holes	**-**	-	**8.0**	**2.1**
Total wells	**-**	**-**	**52.0**	**21.7**
Success rate (%)	**-**	**-**	**85**	**90**

The Company had a successful year with the drill bit resulting in a drilling success rate of 90 percent. The Company has in excess of 100 drilling locations identified within its core areas of operations.

Capital Invested

	Three Months Ended December 31			Twelve Months Ended December 31		
	2006	2005	% Change	**2006**	2005	% Change
Land	**535**	107	400	**3,578**	242	1,379
Seismic	**-**	17	(100)	**10,070**	103	9,677
Drilling and completions	**3,544**	19,618	(82)	**86,473**	37,187	133
Equipping and facilities	**7,646**	8,974	(15)	**62,137**	22,299	179
Property and corporate acquisition	**-**	(94)	(100)	**1,188**	51,273	(98)
Capitalized expenses	**368**	352	5	**1,825**	1,187	54
Other	**31**	82	(62)	**81**	177	(54)
Capital invested	**12,124**	29,056	(58)	**165,352**	112,468	47
Asset retirement costs (net of dispositions)	**(40)**	1,071	(104)	**423**	2,469	(83)
Total capital invested	**12,084**	30,127	(60)	**165,775**	114,937	44

In 2006, Delphi incurred record capital gross expenditures of $165.3 million and disposed of non-core, low working interest properties for approximately $34.9 million resulting in net capital expenditures of $130.4 million. Approximately 55 percent of Delphi's gross capital was allocated to the farm-in at Bigfoot in North East British Columbia which included $40 million in non-recurring infrastructure costs and seismic. Delphi spent approximately $86.5 million participating in the drilling of 52 wells (21.7 net). Delphi drilled 16 wells in Bigfoot paying 90 percent of the costs to earn a 50 percent working interest in the wells. Delphi has satisfied the terms of the Bigfoot farm-in and will participate on a 50/50 basis going forward. The remaining capital was spent on Delphi's core properties in North West Alberta and North East British Columbia, specifically, a major field infrastructure expansion including eight kilometers of new natural gas pipelines and expansion of a field compression facility, and the acquisition of undeveloped sections of land in Delphi's core areas.

Liquidity and Capital Resources

Funding

	Three Months Ended December 31, 2006	Twelve Months Ended December 31, 2006
Sources:		
Funds from operations	11,817	49,551
Issue of shares	-	305
Issue of flow through shares	-	25,003
Property dispositions	17,867	34,918
Change in non-cash working capital	-	-
	29,684	109,777
Uses:		
Cash	757	757
Share issue costs	-	1,725
Capital expenditures	12,124	165,352
Expenditures on site restoration and reclamation	98	503
Change in non-cash working capital	23,416	14,740
	36,395	183,077
Increase in bank debt	6,711	73,300

For the three and 12 months ended December 31, 2006, Delphi funded its capital program through a combination of cash flow, debt, property dispositions and the issuance of flow-through common shares.

Share Capital

At December 31, 2006, the Company had 60.7 million common shares outstanding (December 31, 2005 – 55.3 million). The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and 12 months ended December 31, 2006.

	Three Months Ended December 31, 2006	Twelve Months Ended December 31, 2006
Weighted Average Common Shares		
Basic	60,662	58,051
Diluted	61,584	58,845
Trading Statistics [1]		
High	$ 3.49	$ 5.82
Low	$ 2.39	$ 2.39
Average daily, volume	247,245	148,242

[1] Trading statistics based on closing price.

As at March 6, 2007, the Company had 68.0 million common shares outstanding and 4.2 million stock options outstanding.

Bank Debt plus Working Capital Deficit

At December 31, 2006, the Company had $115.0 million outstanding on its credit facility and a working capital deficit of $3.2 million for total debt plus working capital deficit of $118.2 million excluding the financial asset of $0.3 relating to the unrealized gain on financial commodity contracts. Subsequent to year-end, Delphi issued 7.35 million flow-through common shares at a price of $2.45 per share for gross proceeds of $18.0 million. Delphi anticipates spending projected funds from operations on capital expenditures during 2007.

The capital intensive nature of the industry will generally result in the Company having a working capital deficit. The Company has a revolving facility for $115.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility with a one year term out provision. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to funds flow from operations: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0 percent. In addition to the revolving term facility, the Company has a $10.0 million development facility with its lenders to fund the Bigfoot joint venture. The pricing grid on the development facility is 0.25 percent higher than the revolving term facility.

Financial Strategy

The Company maintains an active risk management program as an integral part of its overall financial strategy to mitigate cash flow volatility resulting from fluctuating commodity prices. Delphi's risk management program consists of both fixed price contracts as well as costless collars, which provide both downside protection and the opportunity to share in the upside if market prices move above the floor price. Currently, Delphi is in the enviable position of having hedged approximately 55 percent of its before-royalty gas production at an average AECO floor price of $8.96 per thousand cubic feet from January 1, 2007 to March 31, 2008. The active risk management program allows the Company to maintain a capital program throughout the first six months of 2007 without an increase in debt levels. The Company is committed to lowering its debt level in 2007 and will minimize the use of leverage in the year with projected debt at the end of the second quarter to be approximately $100.0 million. The Company plans to spend the majority of its capital during the second half of the year, timed with an expected stronger natural gas environment and lower cost of services.

Selected Quarterly Information

The following table sets forth certain information of the Company for the past eight consecutive quarters.

	Dec. 31 2006	Sept. 30 2006	Jun. 30 2006	Mar. 31 2006	Dec. 31 2005	Sept. 30 2005	Jun. 30 2005	Mar. 31 2005
Production								
Oil and NGLs (bbl/d)	829	856	1,034	1,062	1,028	889	865	872
Natural gas (mcf/d)	24,919	25,403	28,797	23,695	22,909	19,580	19,961	16,880
Barrels of oil equivalent (boe/d)	4,982	5,090	5,834	5,011	4,846	4,152	4,192	3,685
Financial								
($000s, except as noted)								
Petroleum and natural gas revenue	22,928	21,587	25,865	23,809	28,961	20,606	17,335	13,978
Funds from operations	11,817	10,902	14,452	12,380	16,118	10,199	7,937	5,958
Per share - Basic	0.19	0.18	0.26	0.22	0.31	0.20	0.16	0.12
Per share - Diluted	0.19	0.18	0.26	0.22	0.31	0.20	0.16	0.12
Net earnings (loss)	290	658	4,768	1,187	6,425	1,190	1,004	(1,942)
Per share - Basic	0.00	0.01	0.09	0.02	0.13	0.02	0.02	(0.04)
Per share - Diluted	0.00	0.01	0.09	0.02	0.12	0.02	0.02	(0.04)
Capital invested	12,124	27,886	44,313	81,029	29,056	16,280	7,096	60,036
Dispositions	(17,867)	(1,331)	(15,720)	-	-	-	-	(5,862)
Net capital expenditures	(5,743)	26,555	28,593	81,029	29,056	16,280	7,096	54,174
Per unit information								
Natural gas ($/mcf)	8.41	7.20	7.59	8.54	11.69	9.30	7.80	7.28
Oil and natural gas liquids ($/bbl)	48.39	61.10	63.43	46.79	45.70	47.15	40.35	37.16
Oil equivalent ($/boe)	50.02	46.10	48.72	52.79	64.94	53.95	45.45	42.13
Operating netback ($/boe)	31.92	27.61	31.28	30.55	39.18	31.17	24.45	23.83

Contractual Obligations

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capacity on a major natural gas processing and gathering system in North East British Columbia. The future minimum commitments are as follows:

2007	$	3,898
2008		3,190
2009		2,992
2010		3,241
2011		2,535
2012 – 2015		6,995

As at December 31, 2006, the Company had incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through shares issued in 2005. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $25.0 million by December 31, 2007 to satisfy the terms of the flow-through common shares issued during 2006.

Guarantees and Off-balance Sheet Arrangements

Delphi has not entered into any off-balance sheet arrangements or guarantees.

Business Conditions and Risk

The business of exploration, development and acquisition of oil and gas reserves involves a number of uncertainties and as a result the Company is exposed to certain business risks inherent in the oil and gas industry which affect results. These business risks can generally be grouped into two major areas: operations, including environmental, and financial.

Operationally, the Company faces risks associated with finding, developing and producing oil and gas reserves. The Company attempts to control operating risks by maintaining a disciplined approach to implementation of the exploration and development program. Exploration risks are managed by hiring experienced technical staff and by concentrating the exploration activity on specific core regions where the Company has experience and expertise. The Company also attempts to operate associated projects where its level of ownership is sufficient. Operational control allows the Company to manage costs, timing and sales of production.

Estimates of economically recoverable reserves and the future net cash flow they will generate are based on a number of factors and assumptions, such as commodity prices, projected production and future capital and operating costs. All of these estimates may vary from actual results. The Company has its reserves evaluated annually by an independent engineering firm and reviews their findings with the Audit Committee of the Board of Directors.

Environmental risks are also associated with field operations. The Company has health and safety programs and procedures and an environmental standards policy. These policies and procedures are designed to protect and maintain the environment with respect to all Company operations. The Company performs an annual third party audit of the safety and environmental policies designed to ensure compliance. Delphi also carries environmental liability, property, drilling and general liability insurance in amounts considered industry standards.

The Company is also exposed to financial risks in the form of commodity prices, interest rates, the Canadian to U.S. dollar exchange rate and inflation. Delphi manages commodity price risks by focusing its capital program on areas that are expected to generate attractive rates of return even at substantially lower commodity prices than the industry is currently receiving. The Company also conducts a commodity price risk management program designed to mitigate large downward movements in commodity prices.

See the Company's 2006 Annual Information Form (AIF) for a further listing of risks.

Critical Accounting Estimates

Delphi's financial statements have been prepared in accordance with Canadian general accepted accounting principles. Certain accounting policies require management to make decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Delphi's management review their estimates frequently; however, the emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates. Delphi attempts to mitigate this risk by employing individuals with the appropriate skill set and knowledge to make reasonable estimates; developing internal reporting systems; and comparing past estimates to actual results.

The Company's financial and operating results include estimates of the following:

- Depletion, depreciation and accretion based on estimates of oil and gas reserves;
- Estimated revenues, operating expenses and royalties for which actual revenues and costs have not been received;
- Estimated capital expenditures on projects that are in progress;
- Estimated fair value of derivative contracts; and
- Estimated amount of the asset retirement obligation including estimates of future costs and the timing of the costs;
- Estimated fair value of the Company in performing the goodwill impairment test.

Future Accounting Pronouncements

In January 2005, the CICA issued Handbook section 3855, Financial Instruments – Recognition and Measurement, Handbook section 3865, Hedges and Handbook section 1530, Comprehensive Income.

Section 3855 establishes standards for the recognition and measurement of financial assets, financial liabilities and non-financial derivatives. The standard specifies when and to which amount a financial instrument is to be recorded on the balance sheet. Financial instruments are to be recorded at fair value in some cases and at cost in others. The section also provides guidance for disclosure of gains and losses on financial instruments.

Section 3865 includes and replaces the guidance on hedging relationships that was previously contained in AcG-13,mostly those relating to the designation of hedging relationships and its documentation. The new standard specifies how to apply hedge accounting and which information has to be disclosed by the entity.

Section 1530 establishes standards for the reporting and presentation of comprehensive income. Comprehensive income includes net income as well as all changes in equity during a period, from transactions and events from non-owner sources. Comprehensive income and its components should be presented in a financial statement with the same prominence as other financial statements.

These sections are to be applied to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. The Company is currently evaluating the impact of these new standards.

Corporate Governance

Overview

The shareholders' interests are a critical factor in the operation and management of Delphi. The Company is committed to maintaining the highest level of investor confidence in the Company through the development of its corporate governance polices. Delphi's Board consists of five independent directors and two officers of the Company who meet regularly to discuss matters of strategy and execution of the business plan. See Delphi's AIF for a listing of committees who oversee specific aspects of the Company's operating and financial strategy.

The application of Bill 198 and its regulations represents an exercise in continuous improvement, which is leading the Company to formalize processes and control measures that are already in place and to introduce new ones. Delphi has chosen to make this a strategic endeavour, which will result in operational improvements and better management.

Disclosure Controls

Beginning in 2005, the Company was required to issue a "Modified Certification of Annual Filings during Transition Period" (Modified Certification) in accordance with Multilateral Instrument 52-109, Certification of Disclosures in Issuers' Annual and Interim Filings. The Modified Certification requires certifying officers to state that they are responsible for establishing and maintaining disclosure controls and procedures and as such have designed such procedures and evaluated their effectiveness as of the end of the period covered by the annual filings. Management believes the disclosure controls and procedures provide a reasonable level of assurance that information required to be disclosed by the Company is recorded, processed, summarized and reported within the time periods specified and the controls and procedures are designed to ensure that information required to be disclosed by the Company is accumulated and communicated to the issuer's management, including its chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure. The Company notes that while it believes the disclosure controls and procedures provide a reasonable level of assurance that they are effective, it does not expect that the disclosure controls and procedures will prevent all errors and fraud. A control system is designed to provide reasonable, not absolute, assurance that the objectives of the control system are met.

Internal Control Over Financial Reporting

In March 2006 Canadian Securities Administrators decided not to proceed with proposed multilateral instrument 52-111 Reporting on Internal Control over Financial Reporting and instead proposed to expand multilateral instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. The major changes resulting from this are that the CEO and CFO will be required to certify in the annual certificates that they have evaluated the effectiveness of internal controls over financial reporting ("ICOFR") as of the end of the financial year and disclose in the annual MD&A their conclusions about the effectiveness of ICOFR. There will be no requirement to obtain an internal control audit opinion from the issuer's auditors concerning management's assessment of the effectiveness of ICOFR. This proposed amendment is expected to apply for the year ended December 31, 2008. Delphi is continuing with its evaluation of ICOFR to ensure it meets the criteria for the proposed certification for December 31, 2008.

The Company's President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer confirm there have been no changes in the Company's internal control over financial reporting that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Outlook

Strategy

Delphi emphasizes a full-cycle approach to its business and strives for internally generated development opportunities as a means of enhancing its production base and ultimately creating value for shareholders. Delphi's goal is to become a dominant natural gas developer and explorer focused in North East British Columbia and North West Alberta. The objective is to develop an inventory of opportunities and undeveloped land base so that production and reserves can be added independent of acquisition activity. In that regard, the Company's ability to add production through the drill bit creates a competitive advantage over those competitors that are reliant upon acquisitions to build or maintain their production base. Currently, Delphi has identified over a hundred drilling locations on in its core areas. Delphi will also continue to pursue acquisitions that will be accretive on a per share basis to cash flow, production, reserves, net asset value and provide significant development opportunities to further enhance value. Delphi believes the long term fundamentals support strong commodity prices particularly in natural gas regardless of the recent price volatility.

2007 Capital Investment and Development Activities

The capital program for 2007 is estimated to be $45 - $50 million, dependent on both field service costs and commodity prices. The Company plans to spend the majority of its capital during the second half of the year, timed with an expected stronger natural gas price environment and lower cost of services. During the near-term period of potentially volatile natural gas prices due to the continued excess of natural gas in storage, the drilling program will favor the Company's oil projects with spending on Delphi's natural gas projects focused on robust capital efficient well recompletions and optimization projects. Delphi's exploration program which requires longer lead-times and targets natural gas will continue with the view of a natural gas price recovery into 2008.

2007 Production Volumes

The production outlook for 2007 will be principally affected by the on stream timing of new production, availability of drilling rigs, service rigs, other oil field services and anticipated drilling activity. Delphi expects to average approximately 5,200 boe/d to 5,400 boe/d with an exit rate of approximately 5,700 boe/d.

Sensitivities

The following table provides projected estimates for 2007 of the sensitivity of the Company's funds flow from operations to changes in a number of variables:

	Funds Flow		Net Earnings	
	Amount	Per share	Amount	Per share
Change of 1.0 mmcf/d in natural gas production	$ 1,500	0.02	$ 100	-
Change of $1.00 per mcf in average gas price	3,500	0.05	2,300	0.03
Change of 1 percent in interest rates	$ 250	-	$ 160	-

SEDAR Filing

Additional information about Delphi is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval (SEDAR) at www.sedar.com and at the Company's website at www.delphienergy.ca.

DELPHI ENERGY CORP.

Consolidated Balance Sheets
As at December 31

($CDN thousands)	**2006**	2005
Assets		
Current assets		
Cash	**757**	-
Accounts receivable	**16,097**	17,907
Prepaid expenses and deposits	**1,460**	11,170
Risk management asset	**348**	-
	18,662	29,077
Property, plant and equipment (Note 4)	**295,906**	203,489
Goodwill	**12,100**	12,100
Total assets	**326,668**	244,666
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**21,492**	47,752
Risk management liability	**-**	645
Bank debt (Note 5)	**-**	41,700
	21,492	90,097
Long term debt (Note 5)	**115,000**	-
Future income taxes (Note 8)	**23,776**	14,292
Asset retirement obligations (Note 6)	**7,951**	7,394
Total liabilities	**168,219**	111,783
Shareholders' equity		
Share capital (Note 7)	**139,108**	123,692
Contributed surplus (Note 7)	**5,627**	2,380
Retained earnings	**13,714**	6,811
Total shareholders' equity	**158,449**	132,883
Total liabilities and shareholders' equity	**326,668**	244,666

Contractual obligations and commitments (Note 10)

Subsequent event (Note 13)

See accompanying notes to the consolidated financial statements.

Approved by the Board,

(“Signed”)
Henry R. Lawrie
Director

(“Signed”)
Lamont C. Tolley
Director

DELPHI ENERGY CORP.

Consolidated Statements of Earnings and Retained Earnings
For the years ended December 31

($CDN thousands, except per unit amounts)	**2006**	2005
Revenue		
Petroleum and natural gas sales	**94,374**	83,764
Realized loss on risk management activities	**(185)**	(2,884)
	94,189	80,880
Royalties (net of Alberta royalty tax credit)	**(13,731)**	(16,335)
Unrealized gain/(loss) on risk management activities	**993**	(645)
	81,451	63,900
Expenses		
Operating	**15,826**	13,041
Transportation	**6,455**	4,893
General and administrative	**2,372**	2,491
Stock-based compensation (Note 7)	**2,491**	1,631
Interest	**6,254**	3,658
Depletion, depreciation and accretion	**40,364**	27,094
	73,762	52,808
Earnings before taxes	**7,689**	11,092
Taxes (Note 8)		
Capital	**-**	250
Future	**786**	4,165
	786	4,415
Net earnings	**6,903**	6,677
Retained earnings, beginning of year	**6,811**	134
Retained earnings, end of year	**13,714**	6,811
Net earnings per share (Note 7)		
Basic	**0.12**	0.13
Diluted	**0.12**	0.13

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.
Consolidated Statements of Cash Flows
For the years ended December 31

($CDN thousands)	**2006**	2005
Cash flow from operating activities		
Net earnings	**6,903**	6,677
Add non cash items:		
Depletion, depreciation and accretion	**40,364**	27,094
Stock-based compensation	**2,491**	1,631
Unrealized loss/(gain) on risk management activities	**(993)**	645
Future taxes	**786**	4,165
Expenditures on site restoration and reclamation	**(503)**	(613)
Change in non-cash working capital (Note 11)	**3,102**	3,167
	52,150	42,766
Cash flow from financing activities		
Issue of shares, net of issue costs	**23,583**	37,906
Decrease in mezzanine debt	**-**	(10,000)
Increase (decrease) in bank debt	**73,300**	(5,700)
	96,883	22,206
Cash flow used in investing activities		
Capital expenditures	**(165,352)**	(61,195)
Acquisition of petroleum and natural gas properties	**-**	(51,273)
Proceeds on the disposition of properties	**34,918**	5,862
Change in non-cash working capital (Note 11)	**(17,842)**	9,742
	(148,276)	(96,864)
Increase in cash and cash equivalents	**757**	(31,892)
Cash and cash equivalents, beginning of year	**-**	31,892
Cash and cash equivalents, end of year	**757**	-
Interest paid	**5,585**	3,387
Taxes paid	**220**	239

See accompanying notes to the consolidated financial statements.

NOTE 1: DESCRIPTION OF BUSINESS

Delphi Energy Corp. ("the Company" or "Delphi") is incorporated under the Business Corporations Act (Alberta) and is a public company listed on the Toronto Stock Exchange. Delphi is primarily engaged in the exploration for and development and production of natural gas properties located in North West Alberta and North East British Columbia and crude oil properties in East Central Alberta.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada. The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results may differ from these estimates.

(a) Principles of consolidation:

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Any reference to the Company refers to the Company and its subsidiaries. All inter-company transactions have been eliminated.

(b) Petroleum and natural gas operations:

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and production equipment. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20% or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted using the unit-of-production method based upon total proved reserves before royalties as determined by independent evaluators. Natural gas reserves and production are converted into equivalent barrels of oil at 6:1 based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The Company is required to perform a ceiling test at least annually to assess the carrying value of oil and gas assets. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves using forecast prices and the lower of cost and market of unproved properties exceed the carrying value of the petroleum and natural gas assets. If the carrying amount of the petroleum and natural gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate.

Depreciation of furniture and office equipment is provided using the declining balance method based upon estimated useful lives of 20% to 50%.

(c) Interest in joint ventures:

Substantially all of the Company's exploration, development and production activities are conducted jointly with others and the financial statements reflect the Company's proportionate interest in such activities.

(d) Goodwill:

Goodwill, at the time of acquisition, represents the excess of purchase price of a business over the fair value of net assets acquired. Goodwill is assessed by the Company for impairment at least each year end. If the fair value of the business is less than the book value, a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the business' assets and liabilities from the fair value of the business to determine the implied fair value of goodwill and comparing that amount to the book value of goodwill. Any excess of the book value of goodwill over the implied fair value is the impairment amount and will be charged to income in the period of the impairment.

(e) Asset retirement obligations:

The Company recognizes the fair value of an asset retirement obligation as a liability at the time it incurs a legal obligation for the future abandonment and reclamation costs associated with its petroleum and natural gas operations. Asset retirement obligations are initially measured at their fair value and subsequently adjusted to reflect the passage of time (accretion) and any changes to the estimated cash flows underlying the obligation. The associated asset retirement cost is capitalized as part of property, plant and equipment and amortized to earnings using the unit of production method over estimated proved reserves consistent with the depletion and depreciation of the underlying asset.

(f) Stock-based compensation:

The Company records a compensation cost for all stock options granted to employees, directors or key consultants over the vesting period of the options based on the fair value method. The compensation cost is a charge to earnings or capitalized as a cost of exploration and development activities with an offsetting increase to contributed surplus on the balance sheet. Consideration paid by employees, directors or key consultants upon exercise of the stock options and the amount previously recognized in contributed surplus are recorded as share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest, rather, the Company accounts for actual forfeitures as they occur.

(g) Future income taxes:

The Company follows the tax liability method of accounting for income taxes. Under this method, estimated future income tax assets and liabilities are determined based upon differences between the carrying amount as reported on the balance sheet and the tax basis of assets and liabilities and measured using substantively enacted tax rates and laws expected to be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the period in which the change occurs. A valuation allowance is recognized against any future income tax assets if it is considered more likely than not that the asset will not be realized.

(h) Flow-through shares:

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. To recognize the foregone tax benefits to the Company, the future income tax liability and share capital are adjusted by the estimated cost of the renounced tax deduction on the date of renouncement.

(i) Per share information:

Basic per share amounts are computed by dividing the net earnings by the weighted average number of common shares outstanding for the year. Diluted per share amounts reflect the potential dilution that would occur if securities or other contracts to issue common shares were exercised or converted to common shares. Diluted per share information is calculated using the treasury stock method that assumes any proceeds received by the Company upon the exercise of in-the-money stock options, plus the unamortized stock based compensation cost, would be used to buy back common shares at the average market price for the period. Anti-dilutive options or instruments are not included in the calculation.

(j) Financial instruments:

Financial instruments consist primarily of accounts receivable, prepaid expenses, accounts payable and accrued liabilities and bank debt. There are no significant differences between the carrying value of these instruments and their estimated fair value.

The Company uses financial instruments for non-trading purposes to manage fluctuations in commodity prices, as described in Note 9. The Company has elected to mark-to-market its financial contracts.

(k) Measurement uncertainty:

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and equipment are based upon estimates of proved petroleum and natural gas reserves, production rates, commodity prices and future costs. The impairment test is based upon estimates of proved and, if applicable, probable reserves, production rates, petroleum and natural gas prices, future costs and other assumptions. The asset retirement obligations are based upon petroleum and natural gas reserves, future costs, expected inflation rates and other assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes to estimates in future periods could be material.

(l) Cash and cash equivalents:

The Company considers deposits in banks, certificates of deposit and short-term investments with original maturities of three months or less and cash in trust as cash and cash equivalents. Bank borrowings are considered to be financing activities.

(m) Revenue recognition:

Crude oil and natural gas revenues are recognized in earnings when title passes from the Company to its customer.

NOTE 3: ACQUISITIONS

On February 1, 2005, the Company acquired producing natural gas and natural gas liquids properties with associated facilities and undeveloped land for cash consideration of $51.3 million. The Company paid for the acquisition with cash and increased bank debt.

NOTE 4: PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2006		**Cost**		**Accumulated depletion and depreciation**		**Net book value**
Petroleum and natural gas properties	**$**	**285,168**	**$**	**71,331**	**$**	**213,837**
Production equipment		**95,892**		**14,087**		**81,805**
Furniture, fixtures and office equipment		**639**		**375**		**264**
	$	**381,699**	**$**	**85,793**	**$**	**295,906**

As at December 31, 2005						
Petroleum and natural gas properties	$	203,264	$	38,035	$	165,229
Production equipment		45,763		7,744		38,019
Furniture, fixtures and office equipment		527		286		241
	$	249,554	$	46,065	$	203,489

As at December 31, 2006, costs in the amount of $35.8 million (December 31, 2005 - $18.9 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $21.7 million (December 31, 2005 - $9.6 million) have been included in costs subject to depletion. All costs of unproved properties have been capitalized. Ultimate recoverability of these costs will be dependent upon finding proved oil and natural gas reserves. The Company performed a separate impairment review of assets excluded from the ceiling test and determined that no impairment has occurred.

The Company capitalized $1.8 million (December, 2005 - $1.2 million) of general and administrative costs directly related to exploration and development activities.

The Company performed a ceiling test calculation at December 31, 2006 to assess the recoverable value of property, plant and equipment, which indicated no write down was required. The future commodity prices used in the impairment test were based on December 31, 2006 commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. The following table summarizes the future benchmark prices the Company used in the impairment test.

	Natural Gas		**Natural Gas Liquids**				**Crude Oil**	
	NYMEX Futures Contract	AECO Spot	Propane	Butane	Pentanes Plus	West Texas Intermediate	Edmonton Light	Bow River Hardisty
	($US/mmbtu)	*($CDN/mmbtu)*	*($CDN/bbl)*	*($CDN/bbl)*	*($CDN/bbl)*	*($US/bbl)*	*($CDN/bbl)*	*($CDN/bbl)*
2007	7.25	7.20	45.00	56.25	71.75	62.00	70.25	49.00
2008	7.50	7.45	43.50	50.25	69.25	60.00	68.00	49.00
2009	7.50	7.75	42.00	48.75	67.00	58.00	65.75	48.75
2010	7.50	7.80	41.25	47.75	65.75	57.00	64.50	48.25
2011	7.50	7.85	41.25	47.75	65.75	57.00	64.50	49.00
2012	7.75	8.15	41.50	48.00	66.25	57.50	65.00	49.50
2013	7.90	8.30	42.50	49.00	67.50	58.50	66.25	50.25
2014	8.05	8.50	43.25	50.25	69.00	59.75	67.75	51.50
2015	8.20	8.70	44.25	51.00	70.50	61.00	69.00	52.50
2016	8.40	8.90	45.00	52.25	72.00	62.25	70.50	53.50
2017	8.55	9.10	46.00	53.00	73.25	63.50	71.75	54.50
Thereafter [1]								

[1] A percentage increase of 2.00% represents the change in future prices each year after 2017 to the end of the reserve life.

NOTE 5: LONG TERM DEBT AND BANK DEBT

The Company has a revolving facility for $115.0 million with a syndicate of Canadian chartered banks. The facility is a 364 day committed revolving facility with a one year term out provision. The current structure of the lending facility is such that amounts outstanding are recognized as a long-term liability. The previous lending agreement was a demand facility and accordingly was classified as a current liability. The credit facility bears interest based on a sliding scale tied to the Company's trailing debt to cash flow: from a minimum of the bank's prime rate to a maximum of the bank's prime rate plus 1.0 percent.

In addition to the revolving term facility, the Company has a $10.0 million development facility with its lenders to fund the Bigfoot joint venture. The pricing grid on the development facility is 0.25 percent higher than the revolving term facility.

The two facilities are secured by a $150.0 million demand floating charge debenture and a general security agreement over all assets of the Company.

NOTE 6: ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations result from working interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations, over the next three to twenty years, is approximately $16.9 million. A credit-adjusted risk-free rate of 8.0 percent and an inflation rate of 2.5 percent were used to calculate the estimated fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

		December 31 2006		December 31 2005
Balance, beginning of year	**$**	**7,394**	$	5,012
Liabilities incurred		**606**		950
Liabilities sold		**(183)**		(250)
Liabilities acquired		**-**		1,604
Liabilities settled		**(503)**		(613)
Change in estimate		-		165
Accretion expense		**637**		526
Balance, end of year	**$**	**7,951**	$	7,394

NOTE 7: SHARE CAPITAL

(a) Authorized:

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(b) Common shares issued:

	December 31, 2006		December 31, 2005	
	Outstanding shares (000's)	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of year	**55,254**	**$ 123,692**	47,704	$ 87,944
Issue of flow-through common shares	**5,209**	**25,003**	4,686	26,004
Issue of common shares	**-**	**-**	2,500	14,000
Exercise of stock options	**200**	**305**	364	643
Allocated from contributed surplus	**-**	**145**	-	323
Share issue costs	**-**	**(1,725)**	-	(2,741)
Future tax effect of share issue costs	**-**	**528**	-	921
Tax benefit renounced to shareholders	**-**	**(8,840)**	-	(3,402)
Balance, end of year	**60,663**	**$ 139,108**	55,254	$ 123,692

On June 29, 2006, the Company issued 5.2 million flow-through common shares at a price of $4.80 per share for gross proceeds of $25.0 million.

On December 29, 2005, the Company issued 2.5 million common shares at a price of $5.60 per share for gross proceeds of $14.0 million.

On December 13, 2005, the Company issued 1.96 million flow-through common shares at a price of $7.15 per share for gross proceeds of $14.0 million.

On March 31, 2005, the Company issued 2.7 million flow-through common shares at a price of $4.40 per share for gross proceeds of $12.0 million.

As at December 31, 2006, the Company had incurred the necessary qualifying exploration expenditures to satisfy the terms of the flow-through shares issued in 2005. Although the Company believes it has incurred the necessary qualifying expenditures, these amounts may be subject to audit and subsequent interpretation by the Canada Revenue Agency. The Company has an obligation to incur qualifying exploration expenditures of $25.0 million by December 31, 2007 to satisfy the terms of the flow-through common shares issued during 2006.

(c) Stock options:

The Company has established a stock option plan under which it has granted options to acquire common shares to certain officers, directors, employees and key consultants. The plan provides for the granting of options equal to ten percent of the issued and outstanding common shares of the Company. Options issued under the plan have a term of five years to expiry and vest over a two-year period starting on the date of the grant. The exercise price of each option equals the closing market price of the Company’s common shares immediately preceding the date of the grant. As at December 31, 2006 there were 4.2 million options to purchase shares outstanding.

The following table summarizes the changes in the number of options outstanding and the weighted average share prices.

	December 31, 2006		December 31, 2005	
	Outstanding options (000's)	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of year	**2,629**	**$ 2.37**	1,895	$ 1.59
Granted	**1,800**	**4.69**	1,165	3.43
Exercised	**(200)**	**1.53**	(364)	1.77
Cancelled	**-**	**-**	(67)	1.85
Balance, end of year	**4,229**	**3.40**	2,629	2.37
Exercisable at end of year	**2,641**	**$ 2.81**	1,755	$ 1.90

The following table summarizes information about the stock options outstanding and exercisable at December 31, 2006.

	Options outstanding			Options exercisable	
Range of exercise price	Outstanding Options (000's)	Weighted average exercise price	Weighted average remaining term	Exercisable (000's)	Weighted average exercise price
$0.99	**343**	**$ 0.99**	**1.2**	**343**	**$ 0.99**
$1.45 - 1.61	**694**	**1.46**	**1.5**	**694**	**1.46**
$1.75 - 1.90	**27**	**1.80**	**2.6**	**27**	**1.80**
$2.66	**200**	**2.66**	**2.9**	**200**	**2.66**
$3.25 - $3.99	**1,190**	**3.35**	**3.2**	**785**	**3.39**
$4.44 - $4.70	**1,635**	**4.65**	**4.2**	**545**	**4.65**
$5.11 - $5.39	**140**	**5.31**	**4.1**	**47**	**5.31**
Total	**4,229**	**$ 3.40**	**3.0**	**2,641**	**$ 2.81**

(d) Stock-based compensation:

The Company accounts for its stock-based compensation using the fair value method for all stock options granted since January 1, 2002. For the year ended December 31, 2006, Delphi recorded non-cash compensation expense of $2.5 million. The Company capitalized $0.9 million (December 31, 2005 - $nil) of stock based compensation directly related to exploration and development activities.

During the year ended December 31, 2006 the Company granted 1.8 million options. The fair values of all options granted during the period are estimated at the date of grant using the Black-Scholes option pricing model. The weighted average fair value of options granted during the period was $2.17 per share (2005 - $1.62). The assumptions used in the Black-Scholes model to determine fair value were as follows:

For the years ended December 31	**2006**	2005
Risk free interest rate (%)	**5.0**	4.5
Expected life (years)	**5.0**	5.0
Expected volatility (%)	**45.0**	48.0

(e) Contributed surplus:

The following table outlines the changes in the contributed surplus balance:

		December 31 2006		December 31 2005
Balance, beginning of year	**$**	**2,380**	$	1,072
Stock-based compensation costs		**3,392**		1,631
Reclassification to common shares on exercise		**(145)**		(323)
Balance, end of year	**$**	**5,627**	$	2,380

(f) Earnings (loss) per share:

Net earnings per share has been based on the following weighted average common shares:

	Twelve Months Ended December 31	
	2006	2005
Basic	**58,051**	50,060
Diluted	**58,845**	50,931

The reconciling item between the basic and diluted weighted average common shares outstanding is stock options.

NOTE 8: TAXES

(a) Expected tax rate:

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the Company's earnings before taxes.

The difference results from the following items:

For the years ended December 31		**2006**		2005
Earnings before income taxes	**$**	**7,689**	$	11,092
Statutory tax rate		**34.74%**		37.67%
Expected income tax expense		**2,671**		4,187
Crown charges		**126**		3,833
Resource allowance		**(4)**		(3,219)
Alberta royalty tax credit		**(74)**		(103)
Stock based compensation		**865**		615
Attributed Canadian Royalty Income (ACRI)		**(226)**		(322)
Rate reduction		**(3,019)**		(187)
Other		**447**		(639)
Capital taxes		**-**		250
Total taxes	**$**	**786**	$	4,415

(b) Future tax liability:

The tax effect of temporary differences that give rise to significant portions of the future tax assets and liabilities at December 31, 2006 and 2005 are presented below:

As at December 31		2006		2005
Future income tax assets:				
Asset retirement obligations	**$**	**2,385**	$	2,486
ACRI		**367**		322
Risk management liability		**-**		230
Share issue costs		**1,569**		1,899
Future income tax liabilities:				
Risk management asset		**(121)**		
Property, plant and equipment		**(27,976)**		(19,229)
Net future income tax liability	**$**	**(23,776)**	$	(14,292)

NOTE 9: FINANCIAL INSTRUMENTS

(a) Fair value of financial instruments:

The Company's exposure under its financial instruments is limited to financial assets and liabilities, all of which are included in these financial statements. The fair values of financial assets and liabilities that are included in the balance sheet approximate their carrying amounts.

(b) Credit risk:

Substantially all of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. With respect to counterparties to financial instruments, the Company partially mitigates associated credit risk by limiting transactions to counterparties with investment grade credit ratings.

(c) Foreign currency exchange risk:

The Company is exposed to foreign currency fluctuations as crude oil and natural gas prices are referenced to U.S. dollar denominated prices.

(d) Interest rate risk:

The Company is exposed to interest rate risk to the extent that bank debt is at a floating rate of interest.

(e) Commodity price risk management:

The Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company sells forward a portion of its future production and enters into a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward contracts are subject to market risk from fluctuating commodity prices and exchange rates.

As at December 31, 2006, the Company has fixed the price applicable to future production through the following contracts:

Time Period	Commodity	Type of Contract	Quantity Contracted	Canadian Price (CDN$/unit)
November 2006 – March 2007	Natural Gas	Physical	2,000 GJ/d	$10.00 fixed
November 2006 – March 2007	Natural Gas	Physical	4,000 GJ/d	$9.50 floor/$10.65 ceiling
November 2006 – March 2007	Natural Gas	Physical	2,000 GJ/d	$9.50 floor/$11.35 ceiling
November 2006 – March 2007	Natural Gas	Physical	4,000 GJ/d	$8.75 floor/$10.00 ceiling
November 2006 – March 2007	Natural Gas	Physical	2,000 mmbtu/d	$11.05 floor/$12.92 ceiling
January 2007 – March 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$10.45 ceiling
April 2007 – October 2007	Natural Gas	Physical	3,000 GJ/d	$8.75 floor/$9.55 ceiling
April 2007 – October 2007	Natural Gas	Physical	4,000 GJ/d	$8.00 floor/$8.92 ceiling
April 2007 – October 2007	Natural Gas	Physical	2,000 mmbtu/d	$8.94 fixed
April 2007 – October 2007	Natural Gas	Physical	2,000 GJ/d	$6.50 floor/$8.15 ceiling
April 2007 – October 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$9.00 ceiling
November 2007 – December 2007	Natural Gas	Financial	2,000 GJ/d	$6.50 floor/$10.45 ceiling
November 2007 – March 2008	Natural Gas	Physical	3,000 GJ/d	$9.00 floor/$9.98 ceiling
November 2007 – March 2008	Natural Gas	Physical	2,000 mmbtu/d	$11.07 fixed
November 2007 – March 2008	Natural Gas	Physical	2,000 GJ/d	$7.75 floor/$9.03 ceiling
April 2008 – October 2008	Natural Gas	Physical	4,000 GJ/d	$7.21 fixed

NOTE 10: CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Company is committed, under contracts of varying lengths, for the utilization of gathering, processing and pipeline capacity on a major natural gas processing and gathering system in North East British Columbia. The future minimum commitments are as follows:

2007	$	3,898
2008		3,190
2009		2,992
2010		3,241
2011		2,535
2012 – 2015		6,995

NOTE 11: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

For the period ended December 31		**2006**		2005
Change in working capital item:				
Accounts receivable	**$**	**1,810**	$	(12,232)
Prepaid Expenses and deposits		**9,710**		(9,872)
Accounts payable and accrued liabilities		**(26,260)**		35,013
Total change in non-cash working capital	**$**	**(14,740)**	$	12,909
Relating to:				
Operating activities		**3,102**		3,167
Financing activities		**-**		-
Investing activities		**(17,842)**		9,742
	$	**(14,740)**	$	12,909

NOTE 12: RECLASSIFICATION

Certain amounts have been reclassified to conform to the presentation in 2006.

NOTE 13: SUBSEQUENT EVENT

On March 1, 2007, the Company issued 7.35 million flow-through common shares at a price of $2.45 per share for gross proceeds of $18.0 million.

Delphi Energy is a Calgary-based company that explores, develops and produces oil and natural gas in Western Canada. The Company is managed by a proven technical team. Delphi trades on the Toronto Stock Exchange under the symbol DEE.

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This news release contains forward-looking statements with respect to Delphi. Forward-looking statements may include estimates, plans, expectations, opinions, forecasts, projections, guidance or other statements that are not statements of fact. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will prove to have been correct. These statements are subject to certain risks and uncertainties and may be based on assumptions that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements. These statements speak only as of the date of this news release.

A barrel of oil equivalent (boe), derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil, may be misleading, particularly if used in isolation. A boe conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Net asset value is calculated as the before tax present value of future net revenue of proved plus probable reserves using escalated pricing discounted at eight percent plus the estimated value of undeveloped land as determined by Seaton Jordan & Associates and seismic, the mark-to-market value of commodity hedging contracts and proceeds on the exercise of in-the-money options less net debt divided by the sum of the number of basic shares outstanding at the end of the year and in-the-money options.

Finding and development costs have been calculated using capital invested during the year, including acquisitions and dispositions, plus the change in future development costs divided by the reserves additions for the year. The aggregate of the exploration and development costs incurred in the most recent financial year, included in capital invested, and the change in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Operating netbacks are calculated as the net revenue received per unit of production after deducting royalties, operating expenses and transportation expenses. Cash netbacks are determined from operating netbacks less general and administrative expenses, interest expense and cash taxes.