press release

1500, 444 - 5 Avenue SW, Calgary, Alberta T2P 2T8
Telephone: (403) 265-6171 Facsimile: (403) 265-6207

Email: info@delphienergy.ca
Website: www.delphienergy.ca
TSX Symbol: DEE

Delphi Energy Corp.

DELPHI ENERGY ACHIEVES CASH FLOW OF $10.9 MILLION IN Q3 2006 AND REPORTS SIGNIFICANT GAINS ON NATURAL GAS HEDGES

CALGARY, ALBERTA – November 14, 2006 – Delphi Energy Corp. is pleased to announce its financial and operational results for the interim period ended September 30, 2006.

Q3 2006 Highlights

- Increased production by 23 percent to 5,090 barrels of oil equivalent per day (boe/d) from 4,152 boe/d during the third quarter of 2005 and increased production by 32 percent to 5,312 boe/d from 4,011 boe/d during the first nine months ended September 30, 2006.
- Increased funds from operations by seven percent to $10.9 million compared to $10.2 million in 2005.
- Mitigated the volatility in natural gas prices and increased funds from operations by $3.5 million ($1.51 per thousand cubic feet) in the third quarter through forward price contracts as part of the Company's ongoing risk management program.
- Completed earning operations in Area 1 at Bigfoot in North East British Columbia resulting in a 50 percent working interest in 75,000 acres of land and adding an estimated 3.3 million barrels of oil equivalent to the Company's reserve base.
- Completed testing operations on a 4,900 metre Leduc exploration well at Tower Creek, Alberta that is expected to add 500 to 600 boe/d net production by the end of the first quarter of 2007.
- Added an estimated six million barrels of oil equivalent to the reserve base from the exploration and development program during the first nine months ended September 30, 2006.
- Achieved operating costs of $5.70 per boe on approximately 90 percent of corporate production in the core growth regions of North West Alberta and North East British Columbia for the nine months ended September 30, 2006 with a corporate average of $8.25 per boe.

Operational Highlights	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Production						
Natural gas (mcf/d)	**25,403**	19,580	30	**25,972**	18,817	38
Crude oil (bbls/d)	**444**	584	(24)	**506**	629	(20)
Natural gas liquids (bbls/d)	**412**	305	35	**477**	246	94
Total (boe/d)	**5,090**	4,152	23	**5,312**	4,011	32
Realized Prices						
Natural gas ($/mcf)	**7.20**	9.30	(23)	**7.91**	8.17	(3)
Crude oil ($/bbl)	**61.02**	45.25	35	**54.73**	39.23	40
Natural gas liquids ($/bbl)	**59.81**	50.79	18	**58.66**	47.76	23

Financial Highlights	Three Months Ended September 30			Nine Months Ended September 30		
($000s except per boe and per share amounts)	**2006**	2005	% Change	**2006**	2005	% Change
Petroleum and natural gas sales	**21,587**	20,607	5	**71,261**	51,920	37
Per boe	**46.10**	53.95	(15)	**49.14**	47.41	4
Funds from operations	**10,902**	10,199	7	**37,734**	24,094	57
Per boe	**23.28**	26.71	(13)	**26.02**	22.01	18
Per share – Basic	**0.18**	0.20	(10)	**0.66**	0.49	35
Per share – Diluted	**0.18**	0.20	(10)	**0.65**	0.48	35
Net earnings	**658**	1,190	(45)	**6,613**	252	2,524
Per boe	**1.40**	3.12	(55)	**4.55**	0.24	1,796
Per share – Basic	**0.01**	0.03	(67)	**0.12**	0.01	1,100
Per share – Diluted	**0.01**	0.03	(67)	**0.11**	0.01	1,000
Capital invested	**27,886**	16,280	71	**153,228**	83,412	84

	September 30 2006	December 31 2005	% Change
Debt plus working capital	**135,640**	60,375	125
Total assets	**352,688**	244,666	44

MESSAGE TO SHAREHOLDERS

Over the last ten months, natural gas prices have fallen from almost $15.00 per thousand cubic feet (mcf) to a low of $3.80 per mcf in mid-September and are currently at approximately $7.60 per mcf. In this challenging environment for natural gas-weighted producers, Delphi managed to increase its production, increase its revenue, increase its cash flow, and decrease its operating costs in the third quarter of 2006 compared with the third quarter of 2005. Delphi's operating netbacks, calculated as the net revenue received per unit of production after deducting royalties, operating expenses and transportation expenses, have remained robust. Operating costs remain less than $1.00 per mcf ($6.00 per boe) in the Company's core growth areas despite the inflationary pressures of service costs experienced over the past year. The Company's risk management program has also been an integral part of its strategy during this phase of growth, providing critical protection to the Company's cash flow during recent periods of high capital demands and volatile natural gas prices. The Company has been able to capture the upside of its natural gas focused areas of Bigfoot in North East British Columbia and Bigstone in North West Alberta through a large capital program during the first nine months of 2006.

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. Cash flow increased by $3.5 million ($1.51 per thousand cubic feet) in the third quarter through forward price contracts. Approximately 47 percent of production is hedged at a floor price of Cdn. $9.90 per mcf for the winter contract period of 2006/2007 and approximately 37 percent of production is hedged at a floor price of Cdn. $8.48 per mcf for the summer contract period of 2007. The debt to cash flow ratio is expected to have peaked during this quarter and should improve through 2007. A sustained natural gas price of Cdn $8.00 per mcf through 2007 would result in a debt to cash flow ratio less than 1.5 times.

In the third quarter of 2006, Delphi drilled two natural gas wells targeting the Jean Marie natural gas resource play in Bigfoot, thus completing the earning phase of the Area 1 joint venture. It is anticipated it will take five to seven years to fully develop the 118 sections of land in the area with Delphi's joint venture partner. The Company has added an estimated 3.3 million barrels of oil equivalent to its reserve base though the 2006 capital program at Bigfoot. The Bigfoot Area 1 joint venture earning phase is comparable to industry property acquisition metrics, and most important, the significant future development of the property is anticipated to cost approximately $12.00 per boe, well below industry averages of approximately $20.00 per boe.

Delphi also drilled and brought on production two natural gas wells in Bigstone during the third quarter, increasing production in the area to almost 3,000 boe/d, a threefold increase from production levels at the time of acquisition 18 months ago. Bigstone continues to provide the Company's highest netback production with operating costs of approximately $0.70 per mcf ($4.20 per boe).

Production testing operations were completed at the Tower Creek exploration well located southwest of the Company's Bigstone property. The well is expected to be tied in by the end of the first quarter of 2007 and brought on production at an initial rate of 500 to 600 boe/d net to Delphi. Reserves associated with this 4,900 metre Leduc discovery are internally estimated at 45 billion cubic feet (bcf) of gross raw gas (1.1 million boe net to Delphi).

Cost of services, wet weather, regulatory delays and operational issues continue to challenge the Company's production growth in its core areas of North West Alberta and North East British Columbia where industry activity remains high. Wet weather has delayed operations and caused an increase in costs while pipeline and processing infrastructure operates near full capacity. Project costs and timelines continue to be monitored closely and adjusted as required. Aggressive project timelines can be achieved, but are typically avoided due to the associated increased costs.

The Company continues to focus on increasing base production volumes by addressing infrastructure constraints and unscheduled downtime on both owned and third-party facilities. Currently, Delphi has approximately 1,200 boe/d of behind pipe capability and restricted productive capability which is expected to be brought on-stream by the end of the first quarter of 2007.

Delphi continues to be excited about the growth opportunities within the Company. The successful development of Bigstone in North West Alberta over the past 18 months, along with the exploration success at Tower Creek and the significant development potential at Bigfoot in North East British Columbia are all examples of the Company's grassroots growth strategies at work.

OPERATIONS

Bigstone, North West Alberta

In the Bigstone area of North West Alberta, Delphi drilled three gas wells (1.30 net) during the third quarter of 2006. Two wells (1.1 net) have been placed on-stream with one producing in excess of 4,000 mcf/d and the other producing 500 mcf/d. These two wells were step-out locations further delineating the orientation of the productive trends identified during the 2005/2006 winter program. In order to delineate the extent of the previously announced light oil discovery, two of the wells drilled for deeper targets in the third quarter, were cored in the productive interval. A well is scheduled to be drilled in December to further test the productivity of this light oil discovery, which could contain as much as 15 million barrels of oil in place.

In preparation for the 2007 drilling program, a total of 14 locations are in various stages of licensing. Nine of the locations will primarily target multiple Cretaceous gas objectives and five will be targeting light oil. The majority of these locations are direct offsets to producing wells in the primary target. Delphi anticipates moving a drilling rig into the area in November to obtain an early start to the 2006/2007 winter drilling program.

Recent start-up of Delphi's 55 percent working interest wells has increased operating pressures in the Bigstone field resulting in a temporary reduction in the deliverability in some of Delphi's 100 percent wells. Ongoing minor modifications to Company-owned infrastructure are expected to eliminate this near term deliverability issue. It is anticipated that incremental volumes from the upcoming winter program will exceed the Company's share of processing capacity at the Bigstone plant and Delphi has developed a plan to access available midstream processing capacity in the area.

Bigfoot, North East British Columbia

In the Bigfoot area of North East British Columbia, Delphi drilled and tied in two gas wells (2.0 net). An additional five wells (2.5 net) were tied in and brought on production bringing the total producing well count to sixteen (9.0 net). Three wells (1.5 net) remain to be tied in as a result of ground conditions and should be on production during January 2007. Current production from the area has stabilized at approximately 550 boe/d net to Delphi. In addition, the remaining well tie-ins and ongoing well and gathering system optimization projects are estimated to add an incremental 150 boe/d during the first quarter of 2007. Discussions are ongoing with Delphi's joint venture partner regarding the development drilling program in Area 1 for the 2006/07 winter season.

The earning phase for Bigfoot Area 1 is now complete and the overall project metrics for the Jean Marie is on track to develop a long life asset with a significant drilling inventory characterized by low risk and low finding and development costs. Based on the initial development phase, internal estimates of proved plus probable reserves are 3.3 million barrels of oil equivalent net to Delphi. The indicated reserves are associated with the 21 wells drilled to date and seven additional locations which fully develops less than 10 percent of the 118 gross sections (50 percent net Delphi). Joint venture earning terms and cost overruns primarily associated with the infrastructure contributed to an all in finding and development cost of approximately $31.00 per boe. Future finding and development costs are estimated to be approximately $12.00 per boe now that the necessary infrastructure is in place to accommodate the significant development potential of this asset. Based on current production rates and the internal reserve estimates, the Bigfoot asset has a Reserve Life Index of approximately 15 years. In addition to the indicated Jean Marie development, several Mississippian and Triassic targets were identified during the 2005/06 drilling program and will be evaluated as part of the 2006/07 winter program.

EXPLORATION ACTIVITY

Tower Creek, Alberta

As previously announced, Delphi's 4,900 metre Tower Creek Leduc well in North West Alberta was completed and production tested at a restricted rate of 15 mmcf/d with a flowing tubing pressure of approximately 3,800 psi from a 95-metre open-hole section. Delphi and its partners have signed an agreement with a midstream company that will construct an 18 kilometre, 8-inch diameter, high-pressure, sour gas pipeline to tie-in the well to the Kaybob South # 3 gas plant for processing, where significant excess capacity is available. The equipping and tie-in is anticipated to be completed by the end of the first quarter of 2007. Initial gross raw gas production rates are estimated to be between 20 and 25 mmcf/d (500 to 600 boe/d net to Delphi).

Delphi plans to participate in a second seismically defined deep exploration test in this area targeting high pressure sweet gas from the highly fractured Wabamun formation. Wabamun analogs in the area have commenced production at gross raw rates of up to 30 mmcf/d of sweet gas. Delphi will pay 23.9 percent of the costs of the well to earn a 20.8 percent in the wellbore and surrounding acreage.

RESERVES

The Company estimates that approximately six million barrels of oil equivalent have been added as a result of the earning activities at Bigfoot, the successful Tower Creek exploration well and activities on Delphi's other major properties. Delphi has initiated the year end reserve audit process, with its independent engineers GLJ Petroleum Consultants, which will incorporate these anticipated additions and adjustments associated with production, acquisitions, dispositions and revisions of existing reserves.

PRODUCTION

Production during the third quarter of 2006 averaged approximately 5,090 boe/d, a 23 percent increase over the comparative quarter in 2005 and a 16 percent decrease from the second quarter of 2006. Production during the third quarter was lower than projected due to an extended turnaround at the Duke facility in British Columbia, facility interruptions at Bigstone, processing constraints in the Grande Prairie areas, natural declines and minor property dispositions during the second quarter of 2006. Production during October averaged approximately 5,500 boe/d with approximately 1,200 boe/d of behind pipe or restricted productive capability. These volumes are expected to be brought on-line through the 2006/2007 winter season.

FINANCIAL REVIEW

Funds from operations for the third quarter of 2006 were $10.9 million ($0.18 per share), an increase of seven percent over the prior year. Cash flow netbacks were $23.28 per boe, a decrease of only 13 percent compared to the second quarter of 2005 despite a 38 percent decrease in AECO pricing over the same period of time. AECO pricing is the benchmark for the Company's natural gas pricing. The lower than expected decline in cash flow netbacks in the third quarter resulted primarily from Delphi's hedging program. The Company received $3.5 million ($1.51 per mcf) in the third quarter from forward price contracts as part of its ongoing commodity risk management program. Delphi's field cost structure remained relatively stable through the third quarter of 2006. An increase in operating costs to $8.62 per boe for the third quarter compared to the second quarter of 2006 was primarily due to reduced production volumes in North East British Columbia as a result of a major maintenance turnaround of third party processing facilities. The Company achieved operating costs of $5.70 per boe on approximately 90 percent of corporate production in its core regions of North East British Columbia and North West Alberta for the nine months ended September 30, 2006. Net earnings for the third quarter of 2006 were $0.7 million ($0.01 per share) compared to $1.2 million ($0.03 per share) in the same quarter of 2005.

Delphi invested $27.9 million in its capital program in the third quarter of 2006. Joint venture billings associated with the Bigfoot capital program were greater than the Company had anticipated. The capital program was funded by cash flow from operations, bank debt and working capital. Subsequent to the end of the quarter, the Company has entered into purchase and sale agreements to sell two minor working interest, non-core properties for approximately $16.3 million. The proceeds will be used to pay down bank debt. The Company expects to fund its fourth quarter capital program through cash flow from operations.

At September 30, 2006, outstanding bank debt was $108.3 million with a working capital deficiency of $27.3 million, including accrued liabilities of $6.7 million, for a total debt plus working capital deficiency of $135.6 million. The Company has a 364 day committed revolving facility of $115 million with a one-year term out provision and a Bigfoot development facility of $10 million. The combination of proceeds from dispositions and a reduced capital program in light of recent natural gas price volatility are expected to result in a debt plus working capital deficiency of approximately $120 million by the end of the year.

OUTLOOK

Delphi is well positioned for sustained long-term growth. The Company's high quality natural gas focused asset base in its growth areas of North West Alberta and North East British Columbia offers a competitive advantage through its low cost structure, infrastructure ownership and significant drilling inventory.

The natural gas price volatility experienced during 2006 combined with the inflated cost of drilling and oilfield services has presented a challenging environment to deliver targeted growth. The Company's capital efficiencies have been further challenged in this environment with the magnitude of the Bigfoot Area 1 joint venture where over-expenditures associated with the infrastructure during the earning phase have contributed to lower than anticipated capital efficiencies. With the infrastructure now in place, development at Bigfoot is anticipated to proceed at better than industry average metrics and second only to Bigstone within the Company's portfolio.

The current weakness in natural gas prices is viewed as short term by the Company with the timing of a recovery as the primary risk factor. Delphi has mitigated this timing risk by hedging approximately 40 percent of natural gas production at an average floor price of approximately Cdn. $9.00 per thousand cubic feet for the remainder of 2006 and 2007. This strategy has provided certainty to the base cash flow assumptions and to the capital programs contemplated through the end of 2007.

The capital program for the remainder of 2006 and 2007 is expected to be funded from cash flow for the period and supplemented with the disposition of certain non-core mature producing and non-producing assets. It is anticipated that capital expenditures will range from $65 to $90 million. Realized natural gas prices will define the level of expenditures. Drilling activity is expected to focus primarily within the Bigstone and Bigfoot properties. A 2007 operating and capital budget will be approved by the Board of Directors in December.

Delphi remains focused on creating shareholder value through its development and exploration programs on its high quality assets. The Company is well positioned for long-term sustainable growth, confidently navigating through this near-term volatility.

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 nine months ended September 30, 2006 and 2005 and should be read in conjunction with the unaudited financial statements and accompanying notes included in this report and the audited financial statements and accompanying notes for the year ended December 31, 2005 included in the Company's 2005 Annual Report. The discussion and analysis has been prepared as of November 7, 2006.

***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 site restoration 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. Throughout this discussion, the term cash flow may used to describe funds from operations.*

***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 September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas (mcf/d)	**25,403**	19,580	30	**25,972**	18,817	38
Crude oil (bbl/d)	**444**	584	(24)	**506**	629	(20)
Natural gas liquids (bbl/d)	**412**	305	35	**477**	246	94
Total (boe/d)	**5,090**	4,152	23	**5,312**	4,011	32

Production for the three months ended September 30, 2006 ("the Quarter") averaged 5,090 boe/d representing an increase of 23 percent over the comparative period primarily due to successful drilling programs at Bigstone, Alberta ("Bigstone") over the past year and in the Bigfoot area in North East British Columbia ("Bigfoot"). Production decreased 12 percent over the second quarter of 2006 due to repairs and maintenance turnarounds at various third party and Company owned processing facilities and the disposition of approximately 150 bbl/d near the end of the second quarter. Delphi had approximately 1,100 boe/d of production shut-in in North East British Columbia for approximately three weeks due to a major facility turnaround. Delphi continues to experience facility interruptions at Bigstone and processing constraints in the Grande Prairie area. The Company estimates there are approximately 1,200 boe/d behind pipe awaiting tie-in which is expected to occur by the end of the first quarter of 2007. The Company's production portfolio for the Quarter was weighted 83 percent to natural gas, nine percent to crude oil and eight percent to natural gas liquids.

Crude oil production was 24 percent lower during the Quarter as compared to the same period 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 September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas						
NYMEX (US $/mmbtu)	**6.12**	10.10	(39)	**7.47**	7.72	(3)
AECO (CDN $/mcf)	**5.72**	9.30	(38)	**6.40**	7.85	(18)
Crude oil						
West Texas Intermediate (US $/bbl)	**70.60**	63.19	12	**68.23**	55.40	23
Edmonton Light (CDN $/bbl)	**80.31**	76.34	5	**75.69**	67.94	11
Foreign exchange rate						
Canadian to US dollar	**1.12**	1.20	(7)	**1.13**	1.22	(7)
US to Canadian dollar	**0.89**	0.83	7	**0.88**	0.82	8

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. During the Quarter AECO natural gas prices continued their downward trend from the second quarter and decreased 38 percent from the comparative period in 2005 and 5 percent from the second quarter of 2006. Natural gas prices have been driven lower by the record amount of gas in storage as a result of the warm winter with storage at the end of September being approximately 3.3 trillion cubic feet with a month of injection season remaining. At the time of writing this MD&A, below average temperatures had spread across North America including the top natural gas consuming regions in Canada and the United States resulting in reported natural gas storage injections being below the seven year average thereby increasing natural gas prices. Delphi expects prices to remain volatile throughout 2006 and 2007 and as such, extended its price protection strategy during the quarter to protect the Company's capital program. Delphi believes the long term fundamentals for natural gas prices are strong particularly when considering the 2007 forward strip price and beyond.

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. Crude oil prices continued to show sustained strength during the Quarter primarily due to geopolitical unrest in major oil producing countries in the Middle East and production disruptions in Alaska. Delphi believes the fundamentals to support natural gas prices in the long term are stronger than oil and accordingly will continue to focus on being primarily a natural gas producer.

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 processing costs. The differential increased from $15.90 per barrel in the second quarter of 2006 to $20.95 per barrel during the Quarter. For the three and nine months ended September 30, 2006 the differential has narrowed relative to the comparative periods.

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 nine months ended September 30, 2006 of $0.6 million related to financial contracts. During the nine months ended September 30, 2006, Delphi recorded a realized loss on financial commodity contracts of $0.2 million. Delphi no longer has any outstanding financial contracts and has entered into physical contracts to reduce the volatility in earnings. The estimated fair value of Delphi's physical contracts at September 30, 2006 was approximately $9.9 million.

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$/GJ)
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.50 floor/$10.90 ceiling
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.19 fixed
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$10.50 floor/$11.15 ceiling
April 2006 – October 2006	Natural Gas	Physical	1,000 GJ/d	$8.32 fixed
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$8.60 ceiling
April 2006 – October 2006	Natural Gas	Physical	4,000 GJ/d	$6.25 fixed
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	$9.89 floor/$11.57 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 [1]
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 [1]
April 2008 – October 2008	Natural Gas	Physical	4,000 GJ/d	$7.21 fixed [1]

[1] Contract entered into subsequent to quarter end.

The contract price on physical contracts is recognized in earnings in the same period as the production revenue.

Realized Sales Prices

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas ($/mcf)	**7.20**	9.57	(25)	**7.93**	8.22	(3)
Gain/(loss) on financial contracts ($/mcf)	**-**	(0.27)	-	**(0.03)**	(0.05)	(48)
Realized gas price ($/mcf)	**7.20**	9.30	(23)	**7.91**	8.17	(3)
Crude oil ($/bbl)	**61.02**	56.36	8	**54.73**	46.10	19
Loss on financial contracts ($/bbl)	**-**	(11.11)	-	**-**	(6.87)	-
Realized oil price ($/bbl)	**61.02**	45.25	35	**54.73**	39.23	40
Natural gas liquids ($/bbl)	**59.81**	50.79	18	**58.66**	47.76	23
Total realized sales price ($/boe)	**46.10**	53.95	(15)	**49.14**	47.41	4

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 nine months ended September 30, 2006. During the three and nine months ended September 30, 2006, Delphi also 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 price received during the Quarter by approximately $1.51 per mcf and $1.06 per mcf year to date. The increase in the average oil price received by Delphi during the three and nine months ended September 30, 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. 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 September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Natural gas	**16,827**	17,238	(2)	**56,246**	42,247	33
Crude oil	**2,493**	3,030	(18)	**7,561**	7,916	(4)
Natural gas liquids	**2,267**	1,421	60	**7,639**	3,210	138
Realized loss on financial contracts	**-**	(1,082)	(100)	**(185)**	(1,453)	(87)
Total	**21,587**	20,607	5	**71,261**	51,920	37

The increase in revenue over the comparative period is attributable to increased production volumes offset by a decrease in the price received due to lower natural gas prices. Revenue decreased 16 percent compared to the second quarter of 2006 due to a 12 percent decrease in production volumes and a five percent decrease in the sales price. Revenue for the nine months ended September 30, 2006 increased 37 percent over the comparative period due to a 32 percent increase in production volumes and a four percent increase in the average price received.

Royalties

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Crown	**3,350**	4,145	(19)	**13,006**	10,385	25
Freehold and gross overriding	**252**	289	(13)	**705**	884	(20)
Total	**3,602**	4,434	(19)	**13,711**	11,269	22
Royalty credits	**(939)**	(621)	51	**(2,790)**	(1,479)	89
Net	**2,663**	3,813	(30)	**10,921**	9,790	12
Per boe	**5.69**	9.98	(43)	**7.53**	8.94	(16)
Percent of total revenue	**12.3**	18.0		**15.3**	18.0	

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 Quarter, royalties as a percentage of revenue decreased to 12 percent due to Delphi realizing approximately $3.5 million in hedging gains, included in revenue, but on which royalties are not paid and a decrease in the price of natural gas. In Alberta, Delphi pays royalties based on the provincial reference price not the prices received resulting in Delphi not paying royalties on the incremental $3.5 million in hedging gains. Delphi is expecting royalties as a percentage of revenue before hedging to be between 17 – 20 percent in the fourth quarter of 2006.

Royalty credits for the three and nine month period ended September 30, 2006 are higher than the comparative periods due to the acquisition of the Bigstone property and 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. Prospectively, Delphi expects total quarterly royalty credits to be approximately $1.3 million.

Operating Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Total	**4,035**	3,666	10	**11,967**	9,518	26
Per boe	**8.62**	9.60	(10)	**8.25**	8.69	(5)

Operating expenses on a per boe basis for the three and nine month period ended September 30, 2006, decreased ten percent and 5 percent over the comparative period despite an environment which faces strong inflationary pressures. Operating costs on a per boe basis increased six percent over the prior quarter due to decreased volumes in North East British Columbia resulting from the turnaround of third party processing facilities. Delphi is expecting operating costs to return to the $8.00 level realized in the first and second quarter of 2006. Delphi's core regions in North East British Columbia and North West Alberta account for 90 percent of Delphi's production with operating costs averaging approximately $5.70 per boe. Delphi believes its East Central Alberta assets mask the high quality of the Company's asset base due to the disproportionate amount of costs attributable to the East Central assets.

Transportation Expenses

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Total	**1,733**	1,224	42	**4,828**	3,475	39
Per boe	**3.70**	3.20	16	**3.33**	3.17	5

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 nine months ended September 30, 2006 increased over the comparative periods due to production from the Bigfoot area being brought on-stream in the second quarter of 2006. Transportation costs increased 10 percent on a per boe basis from the second quarter due to production volumes in North East British Columbia being shut-in with Delphi still being responsible for paying the cost of firm service. The Company expects a five to 10 percent decrease in transportation costs on a per boe basis in the fourth quarter of 2006.

During the Quarter, approximately 29 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.

General and Administrative

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
General and administrative costs	**1,118**	1,211	(8)	**4,158**	3,414	22
Overhead recoveries	**(202)**	(180)	12	**(944)**	(435)	117
Salary allocations	**(414)**	(263)	57	**(1,631)**	(911)	79
Net	**502**	768	(35)	**1,583**	2,068	(23)
Per boe	**1.07**	2.01	(47)	**1.09**	1.89	(42)

On a per boe basis, general and administrative (G&A) costs for the three and nine months ended September 30, 2006 decreased 47 percent and 42 percent over the comparative periods in 2005. On a gross basis, G&A for the nine months ended September 30, 2006 has increased 22 percent commensurate with increased staffing and activity levels. In order for the Company to have continued success it is paramount that Delphi retains its current staff and have the ability to continue to attract highly qualified professionals as needed. As anticipated, G&A per boe has decreased as additional production has been tied in with a minimal amount of increased personnel costs. Management anticipates G&A expense to average between $1.00 and $1.25 in the fourth quarter of 2006.

For the three and nine months ended September 30, 2006, salary allocations have increased by 57 percent and 79 percent due to increased technical staff efforts toward the Company's exploration and development program. Overhead recoveries have increased over the comparative periods due to higher capital spending.

Stock-based Compensation

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Total	**315**	266	18	**2,174**	1,249	74
Per boe	**0.67**	0.70	(4)	**1.50**	1.14	32

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 nine month period ended September 30, 2006 increased 74 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. In the current competitive environment, Delphi has been able to retain all key employees and add additional strength to the team which is a testament to both the option plan and the commitment of the Delphi team. Pursuant to Delphi's option plan, one-third of the options granted vest immediately resulting in higher initial compensation expense. During the Quarter, Delphi capitalized $0.6 million of stock based compensation associated with exploration and development activities.

Interest

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Total	**1,752**	845	107	**4,228**	2,775	52
Per boe	**3.74**	2.21	69	**2.92**	2.53	15

Interest expense on a per boe basis increased 69 percent and 15 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 second quarter due to higher debt balances and lower production volumes.

Depletion, Depreciation and Accretion

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Depletion and depreciation	**9,345**	6,316	48	**28,637**	18,239	57
Accretion expense	**161**	133	21	**464**	360	29
Total	**9,506**	6,449	47	**29,101**	18,599	56
Per boe	**20.31**	16.88	20	**20.07**	16.98	18

Depletion, depreciation, and accretion per boe increased 20 percent and 18 percent, respectively, for the three and nine months ended September 30, 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 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 nine months ended September 30, 2006 increased 21 percent and 29 percent over the comparative periods. The increase is due to an extensive drilling program in 2006.

Taxes

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Capital	**-**	92	(100)	**-**	201	(100)
Future (recovery)	**423**	446	(5)	**491**	701	(30)
Total	**423**	538	(21)	**491**	902	(46)

The provision for future income taxes for the Quarter was an expense of $0.4 million resulting in an effective rate of 39 percent. The nine months ended September 30, 2006 includes a recovery of $2.5 million relating to a reduction in future federal and provincial income tax rates enacted during the second quarter. Delphi does not anticipate it will be cash taxable until 2008 or later based on current commodity prices.

Funds from Operations

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Net earnings	**658**	1,190	(45)	**6,613**	252	2,524
Non-cash items						
Depletion, depreciation and accretion	**9,506**	6,449	47	**29,101**	18,599	56
Unrealized loss/(gain) on risk management activities	**-**	1,848	(100)	**(645)**	3,293	-
Stock-based compensation expense	**315**	266	18	**2,174**	1,249	74
Future income taxes	**423**	446	(5)	**491**	701	(30)
Funds from operations	**10,902**	10,199	7	**37,734**	24,094	57

For the three and nine months ended September 30, 2006 funds from operations were $10.9 million ($0.18 per basic share) and $37.7 million ($0.66 per basic share) compared to $10.2 million ($0.20 per basic share) and $24.1 million ($0.49 per basic share).

Net Earnings

For the three and nine months ended September 30, 2006, Delphi recorded net earnings of $0.7 million and $6.6 million. Earnings for the nine months ended September 30, 2006 were adversely affected by non-cash items such as depletion, depreciation, accretion, stock-based compensation and future income taxes.

Netback Analysis

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Barrels of oil equivalent ($/boe)						
Realized sales price	**46.10**	53.95	(15)	**49.14**	47.41	4
Royalties, net of ARTC	**5.69**	9.98	(43)	**7.53**	8.94	(16)
Operating expenses	**8.62**	9.60	(10)	**8.25**	8.69	(5)
Transportation	**3.70**	3.20	16	**3.33**	3.17	5
Operating netback	**28.09**	31.17	(10)	**30.03**	26.61	13
G&A	**1.07**	2.01	(47)	**1.09**	1.89	(42)
Interest	**3.74**	2.21	69	**2.92**	2.53	15
Current taxes	**-**	0.24	(100)	**-**	0.18	(100)
Cash netback	**23.28**	26.71	(13)	**26.02**	22.01	18
Unrealized (gain)/loss on financial contracts	**-**	4.84	(100)	**(0.44)**	3.01	-
Stock-based compensation expense	**0.67**	0.70	(4)	**1.50**	1.14	32
Depletion, depreciation and accretion	**20.31**	16.88	20	**20.07**	16.98	18
Future income taxes (recovery)	**0.90**	1.17	(23)	**0.34**	0.64	(47)
Net earnings (loss)	**1.40**	3.12	(55)	**4.55**	0.24	1,796

During the Quarter cash netbacks decreased 13 percent from the comparable period and decreased 14 percent from the prior quarter of 2006. Approximately 80 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.

Drilling Results

	Three Months Ended September 30		Nine Months Ended September 30	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**5.0**	**3.3**	**43.0**	**19**
Oil wells	**-**	-	**1.0**	**0.6**
Dry holes	**-**	-	**8.0**	**2.1**
Total wells	**5.0**	**3.3**	**52.0**	**21.7**
Success rate (%)	**100**	**100**	**85**	**90**

Capital Invested

	Three Months Ended September 30			Nine Months Ended September 30		
	2006	2005	% Change	**2006**	2005	% Change
Land	**90**	-	-	**3,043**	135	2,154
Seismic	**20**	26	(23)	**10,070**	85	11,747
Drilling and completions	**14,232**	10,293	38	**82,929**	17,569	372
Equipping and facilities	**13,154**	5,596	135	**54,491**	13,325	309
Property and corporate acquisition	**-**	95	(100)	**1,188**	51,369	(98)
Capitalized expenses	**370**	238	55	**1,457**	835	74
Other	**20**	32	(38)	**50**	94	(47)
Capital invested	**27,886**	16,280	71	**153,228**	83,412	84
Asset retirement costs	**95**	-	-	**463**	1,398	(67)
Total capital invested	**27,981**	16,280	72	**153,691**	84,810	81

Delphi's third Quarter capital program of $27.9 million continued to be focused in North West Alberta with the drilling of three natural gas wells and the completion of earning operations in Area 1 at Bigfoot in North East British Columbia. In Bigfoot, Delphi drilled and tied in two wells (2.0 net) and tied in and brought on-stream five additional wells (2.5 net) which had been drilled in the first and second quarter of 2006 or in the partner's previous drilling program.

During the Quarter, with the completion of operations in Area 1 at Bigfoot, joint venture billings received from the operator of the Bigfoot joint venture were greater than expected, primarily on the infrastructure costs associated with the all-season road and transmission pipeline. This had the affect of increasing capital in the Quarter by approximately $ 11.9 million.

Liquidity and Capital Resources

Funding

	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006
Sources:		
Funds from operations	10,902	37,734
Issue of shares	-	305
Issue of flow through shares	-	25,003
Property dispositions	1,331	17,051
Change in non-cash working capital	-	8,676
	12,233	88,769
Uses:		
Share issue costs	48	1,725
Capital expenditures	27,886	153,228
Expenditures on site restoration and reclamation	65	405
Change in non-cash working capital	2,523	-
	30,522	155,358
Increase in bank debt	18,289	66,589

For the nine month period ended September 30, 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 September 30, 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 nine months ended September 30, 2006.

	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2006
Weighted Average Common Shares		
Basic	60,662	57,171
Diluted	61,584	58,037
Trading Statistics		
High	$ 4.84	$ 5.82
Low	$ 2.88	$ 2.88
Average daily, volume	123,677	115,765

(1) Trading statistics based on closing price.

As at November 7, 2006, the Company had 60.7 million common shares outstanding and 4.2 million stock options outstanding.

Bank Debt plus Working Capital Deficit

At September 30, 2006, the Company had $108.3 million outstanding on its credit facility and a working capital deficit of $27.3 million for total debt plus working capital deficit of $135.6 million. Subsequent to Quarter end, Delphi entered into purchase and sale agreements to sell two minor working interest, non-core properties producing approximately 250 barrels of oil equivalent per day for total consideration of $16.3 million. Delphi continues to dispose of non-strategic assets in order to allocate capital to low operating cost and high growth properties such as Bigstone and Bigfoot. The Company's anticipated funds from operations and the sale of non-core assets are expected to be sufficient to meet the current working capital deficit and bring the debt plus working capital deficiency in line with the Company's credit facilities. Delphi anticipates spending less than funds from operations on capital expenditures during the fourth quarter.

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 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.

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. As additional natural gas volumes have been brought on-stream, the Company has executed additional physical natural gas forward contracts for the winter contract period of 2006/2007, the summer of 2007, winter 2007/2008 and summer of 2008. Currently, Delphi is in the enviable position of having hedged approximately 45 percent of its before-royalty gas production at an average AECO floor price of $9.40 per gigajoule (GJ) through the end of March of 2007 resulting in an average wellhead realization of approximately $9.90 per thousand cubic feet on that portion of Delphi's natural gas which is hedged. For the summer period of 2007, Delphi has hedged approximately 38 percent of its before-royalty gas production at an average AECO floor price of $8.05 per GJ resulting in an average wellhead realization of approximately $8.48 per thousand cubic feet on the portion of Delphi's natural gas which is hedged. The active risk management program allows the Company to have an active drilling program throughout the first six months of 2007 without an increase in debt levels.

Selected Quarterly Information

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

	Sept. 30 2006	Jun. 30 2006	Mar. 31 2006	Dec. 31 2005	Sept. 30 2005	Jun. 30 2005	Mar. 31 2005	Dec. 31 2004
Production								
Oil and NGLs (bbl/d)	856	1,034	1,062	1,028	889	865	872	903
Natural gas (mcf/d)	25,403	28,797	23,695	22,909	19,580	19,961	16,880	6,849
Barrels of oil equivalent (boe/d)	5,090	5,834	5,011	4,846	4,152	4,192	3,685	2,045
Financial								
($000s, except as noted)								
Petroleum and natural gas revenue	21,587	25,865	23,809	28,961	20,606	17,335	13,978	7,459
Funds from operations	10,902	14,452	12,380	16,118	10,199	7,937	5,958	2,748
Per share - Basic	0.18	0.26	0.22	0.31	0.20	0.16	0.12	0.09
Per share - Diluted	0.18	0.26	0.22	0.31	0.20	0.16	0.12	0.09
Net earnings (loss)	658	4,768	1,187	6,425	1,190	1,004	(1,942)	(679)
Per share - Basic	0.01	0.09	0.02	0.13	0.02	0.02	(0.04)	(0.02)
Per share - Diluted	0.01	0.09	0.02	0.12	0.02	0.02	(0.04)	(0.02)
Capital invested	27,886	44,313	81,029	29,056	16,280	7,096	60,036	62,417
Per unit information								
Natural gas ($/mcf)	7.20	7.59	8.54	11.69	9.30	7.80	7.28	7.02
Oil and natural gas liquids ($/bbl)	61.10	63.43	46.79	45.70	47.15	40.35	37.16	37.57
Oil equivalent ($/boe)	46.10	48.72	52.79	64.94	53.95	45.45	42.13	39.66
Operating netback ($/boe)	28.09	31.28	30.55	39.18	31.17	24.45	23.83	20.92

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:

2006	$	1,026
2007		3,766
2008		3,150
2009		2,894
2010		2,521
2011 – 2016		9,400

On November 23, 2005, the Company announced a farm-in agreement with a major producer to jointly develop a natural gas resource play in the Bigfoot area of North East British Columbia, an opportunity distinct from the Bigstone property in North West Alberta. The Company will pay 90 percent of the capital expenditures up to $81.0 million to earn a 50 percent working interest on 118 sections (75,520 acres) from the partner. Pursuant to the agreement, the Company has provided the partner with a $10.0 million deposit towards these expenditures. As at September 30, 2006, Delphi has fulfilled the commitment relating to the farm-in.

The Company's lease rental commitment on office premises from 2006 through 2008 is $0.1 million per annum.

As at September 30, 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 2005 Annual Information Form (AIF) for a further listing of risks.

Critical Accounting Estimates

Delphi’s financial statements have been prepared in accordance with Canadian generally 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 value of the asset retirement obligation including estimates of future costs and the timing of the costs.

Corporate Governance

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.

Beginning in 2005, the Company is 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 or internal controls over financial reporting 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.

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 (unaudited)

($CDN thousands)	**September 30 2006**	December 31 2005
Assets		
Current assets:		
Accounts receivable	**17,204**	17,907
Prepaid expenses and deposits (Note 8)	**11,049**	11,170
	28,253	29,077
Property, plant and equipment (Note 3)	**312,335**	203,489
Goodwill	**12,100**	12,100
Total assets	**352,688**	244,666
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities	**55,604**	47,752
Risk management liability	**-**	645
Bank debt (Note 4)	**-**	41,700
	55,604	90,097
Long term debt (Note 4)	**108,289**	-
Future income taxes	**23,348**	14,292
Asset retirement obligations (Note 5)	**7,916**	7,394
Total liabilities	**195,157**	111,783
Shareholders’ equity		
Share capital (Note 6)	**139,108**	123,692
Contributed surplus (Note 6)	**4,999**	2,380
Retained earnings	**13,424**	6,811
Total shareholders' equity	**157,531**	132,883
Total liabilities and shareholders' equity	**352,688**	244,666

Contractual obligations and commitments (Note 8)

Subsequent event (Note 10)

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 (unaudited)
For the three and nine months ended September 30

($CDN thousands, except per unit amounts)	Three Months Ended September 30 **2006**	2005	Nine Months Ended September 30 **2006**	2005
Revenue:				
Petroleum and natural gas sales	**21,587**	21,689	**71,446**	53,373
Realized loss on risk management activities	**-**	(1,082)	**(185)**	(1,453)
	21,587	20,607	**71,261**	51,920
Royalties (net of Alberta royalty tax credit)	**(2,663)**	(3,813)	**(10,921)**	(9,790)
Unrealized gain/(loss) on risk management activities	**-**	(1,848)	**645**	(3,293)
	18,924	14,946	**60,985**	38,837
Expenses:				
Operating	**4,035**	3,666	**11,967**	9,518
Transportation	**1,733**	1,224	**4,828**	3,475
General and administrative	**502**	768	**1,583**	2,068
Stock-based compensation (Note 6)	**315**	266	**2,174**	1,249
Interest	**1,752**	845	**4,228**	2,775
Depletion, depreciation and accretion	**9,506**	6,449	**29,101**	18,599
	17,843	13,218	**53,881**	37,684
Earnings before taxes	**1,081**	1,728	**7,104**	1,153
Taxes:				
Capital	**-**	92	**-**	200
Future	**423**	446	**491**	701
	423	538	**491**	901
Net earnings	**658**	1,190	**6,613**	252
Retained earnings (deficit), beginning of period	**12,766**	(804)	**6,811**	134
Retained earnings, end of period	**13,424**	386	**13,424**	386
Net earnings per share (Note 6)				
Basic	**0.01**	0.03	**0.12**	0.01
Diluted	**0.01**	0.03	**0.11**	0.01

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.

Consolidated Statements of Cash Flows (unaudited)
For the three and nine months ended September 30

	Three Months Ended September 30		Nine Months Ended September 30	
($CDN thousands)	**2006**	2005	**2006**	2005
Cash flow from operating activities				
Operations:				
Net earnings	**658**	1,190	**6,613**	252
Add non cash items:				
Depletion, depreciation and accretion	**9,506**	6,449	**29,101**	18,599
Stock-based compensation	**315**	266	**2,174**	1,249
Unrealized loss/(gain) on risk management activities	**-**	1,848	**(645)**	3,293
Future taxes	**423**	446	**491**	701
Expenditures on site restoration and reclamation	**(65)**	-	**(405)**	-
Change in non-cash working capital (Note 9)	**(12,027)**	(3,438)	**5,325**	(4,067)
	(1,190)	6,761	**42,654**	20,027
Cash flow from financing activities				
Issue of common shares, net of issue costs	**-**	395	**286**	11,776
Issue of flow-through common shares, net of issue costs	**(48)**	-	**23,297**	-
Decrease in mezzanine debt	**-**	-	**-**	(10,000)
Increase in bank debt	**18,289**	(2,600)	**66,589**	10,900
	18,241	(2,205)	**90,172**	12,676
Cash flow used in investing activities				
Capital expenditures	**(27,886)**	(16,280)	**(153,228)**	(32,139)
Acquisition of petroleum and natural gas properties	**-**	-	-	(51,273)
Proceeds on the disposition of properties	**1,331**	-	**17,051**	5,863
Change in non-cash working capital (Note 9)	**9,504**	11,724	**3,351**	12,954
	(17,051)	(4,556)	**(132,826)**	(64,595)
Decrease in cash and cash equivalents	**-**	-	**-**	(31,892)
Cash and cash equivalents, beginning of period	**-**	-	**-**	31,892
Cash and cash equivalents, end of period	**-**	-	**-**	-
Interest paid	**1,618**	385	**3,654**	2,198
Taxes paid	**-**	-	**220**	155

See accompanying notes to the consolidated financial statements.

DELPHI ENERGY CORP.

Notes to Consolidated Financial Statements
As at and for the periods ended September 30, 2006 and 2005 (unaudited)
(all tabular amounts are expressed in thousands of CDN dollars, except per unit amounts)

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 unaudited interim consolidated financial statements of Delphi have been prepared by management in accordance with accounting principles generally accepted in Canada and following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2005. The disclosures provided below are incremental to those included with the annual financial statements. The interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's Annual Report for the year ended December 31, 2005.

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.

NOTE 3: PROPERTY, PLANT AND EQUIPMENT

As at September 30, 2006		**Cost**		**Accumulated depletion and depreciation**		**Net book value**
Petroleum and natural gas properties	**$**	**290,272**	**$**	**61,787**	**$**	**228,485**
Production equipment		**96,123**		**12,602**		**83,521**
Furniture, fixtures and office equipment		**641**		**313**		**328**
	$	**387,036**	**$**	**74,702**	**$**	**312,334**

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 September 30, 2006, costs in the amount of $44.5 million (December 31, 2005 - $18.9 million) representing unproved properties were excluded from the depletion calculation and estimated future development costs of $21.9 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 $1.5 million (September 30, 2005 - $0.8 million) of general and administrative costs directly related to exploration and development activities.

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: 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 5: 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 $17.1 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.

		September 30 2006		December 31 2005
Balance, beginning of period	**$**	**7,394**	$	5,012
Liabilities incurred		**497**		950
Liabilities sold		**(34)**		(250)
Liabilities acquired		**-**		1,604
Liabilities settled		**(405)**		(613)
Change in estimate		**-**		165
Accretion expense		**464**		526
Balance, end of period	**$**	**7,916**	$	7,394

NOTE 6: SHARE CAPITAL

(a) Authorized:

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(b) Common shares issued:

	September 30, 2006		December 31, 2005	
	Outstanding shares (000's)	**Amount**	Outstanding shares (000's)	Amount
Balance, beginning of period	**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 period	**60,663**	**$ 139,108**	55,254	$ 123,692

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.

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 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 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.

(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 September 30, 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.

	September 30, 2006		December 31, 2005	
	Outstanding options (000's)	**Weighted average exercise price**	Outstanding options (000's)	Weighted average exercise price
Balance, beginning of period	**2,629**	**$ 2.37**	1,895	$ 1.59
Granted	**1,775**	**4.70**	1,165	3.43
Exercised	**(200)**	**1.53**	(364)	1.77
Cancelled	**-**	**-**	(67)	1.85
Balance, end of period	**4,204**	**3.39**	2,629	2.37
Exercisable at end of period	**2,566**	**$ 2.81**	1,755	$ 1.90

The following table summarizes information about the stock options outstanding and exercisable at September 30, 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**	**1.4**	**343**	**$ 0.99**
$1.45 - 1.61	**694**	**1.46**	**1.7**	**694**	**1.46**
$1.75 - 1.90	**27**	**1.80**	**2.8**	**27**	**1.80**
$2.66	**200**	**2.66**	**3.1**	**133**	**2.66**
$3.25 - $3.77	**1,165**	**3.43**	**3.5**	**777**	**3.43**
$4.44 - $4.70	**1,635**	**4.65**	**4.4**	**545**	**4.65**
$5.11 - $5.39	**140**	**5.31**	**4.4**	**47**	**5.31**
Total	**4,204**	**$ 3.39**	**3.3**	**2,566**	**$ 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 nine month period ended September 30, 2006, Delphi recorded non-cash compensation expense of $2.8 million. The Company capitalized $0.6 million (September 30, 2005 - $nil) of stock based compensation directly related to exploration and development activities.

During the nine month period ended September 30, 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 $2.18 per share (2005 - $1.62). The assumptions used in the Black-Scholes model to determine fair value were as follows:

Period ended September 30	**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:

	September 30 2006	December 31 2005
Balance, beginning of period	**$ 2,380**	$ 1,072
Stock-based compensation costs	**2,764**	1,631
Reclassification to common shares on exercise	**(145)**	(323)
Balance, end of period	**$ 4,999**	$ 2,380

(f) Earnings (loss) per share:

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Basic	**60,662**	50,650	**57,171**	49,665
Diluted	**61,584**	51,606	**58,037**	50,091

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

NOTE 7: 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. The contract price on physical contracts is recognized in earnings in the same period as the production revenue.

As at September 30, 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$/GJ)
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.50 floor/$10.90 ceiling
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$9.19 fixed
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$10.50 floor/$11.15 ceiling
April 2006 – October 2006	Natural Gas	Physical	1,000 GJ/d	$8.32 fixed
April 2006 – October 2006	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$8.60 ceiling
April 2006 – October 2006	Natural Gas	Physical	4,000 GJ/d	$6.25 fixed
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	$9.89 floor/$11.57 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
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

NOTE 8: 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:

2006	$	1,026
2007		3,766
2008		3,150
2009		2,894
2010		2,521
2011 – 2016		9,400

On November 23, 2005, the Company announced a farm-in agreement with a major producer to jointly develop a natural gas resource play in the Bigfoot area of North East British Columbia. The Company will pay 90 percent of the capital expenditures up to $81.0 million to earn a 50 percent working interest on 118 sections (75,520 acres) from the partner. Pursuant to the agreement, the Company has provided the partner with a $10.0 million deposit towards these expenditures. As at September 30, 2006, Delphi has fulfilled the commitment relating to the farm in.

The Company's lease rental commitment on office premises from 2006 through 2008 is $0.1 million per annum.

NOTE 9: CHANGES IN NON-CASH WORKING CAPITAL ITEMS

For the period ended September 30		**2006**		2005
Change in working capital item:				
Accounts receivable	**$**	**703**	$	(6,354)
		121		8
Accounts payable and accrued liabilities		**7,852**		15,233
Total change in non-cash working capital	**$**	**8,676**	$	8,887
Relating to:				
Operating activities		**5,325**		(4,067)
Financing activities		**-**		-
Investing activities		**3,351**		12,954
	$	**8,676**	$	8,887

NOTE 10: SUBSEQUENT EVENT

Subsequent to quarter end, Delphi entered into purchase and sale agreements to sell two minor working interest, non-core properties producing approximately 250 barrels of oil equivalent per day for total consideration of $16.3 million. Closing is expected to occur at the end of November. Proceeds from the dispositions will be used to repay long term debt.

Delphi's complete third quarter 2006 financial statements and management's discussion and analysis are available on Delphi's website at www.delphienergy.ca and will be available on SEDAR at www.sedar.com within 24 hours.

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

FOR FURTHER INFORMATION PLEASE CONTACT:

DELPHI ENERGY CORP.
1500, 444 – 5 Avenue S.W.
Calgary, Alberta
T2P 2T8

Telephone: (403) 265-6171
Facsimile: (403) 265-6207
Email: info@delphienergy.ca
Website: www.delphienergy.ca

DAVID J. REID
President & CEO

BRIAN KOHLHAMMER
V.P. Finance & CFO

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.

The terms “funds from operations”, “funds from operations per share” and “netbacks” 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 are calculated as net earnings plus the addback on non-cash items (depletion, depreciation and amortization, stock-based compensation, future income taxes and unrealized (gain)/loss on risk management activities) and exclude the change in non-cash working capital related to operating activities and expenditures on site restoration and reclamation. 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.