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SECOND QUARTER 2005 **Six Months Ended June 30, 2005** DEE – TSX

Second Quarter 2005 Highlights

- Increased production 144 percent to 4,192 barrels of oil equivalent per day (boe/d) in the second quarter of 2005 from 1,716 boe/d in the second quarter of 2004 and up 14 percent from 3,685 boe/d in the first quarter of 2005.
- Increased cash flow from operations before change in non-cash working capital 144 percent to $7,936,766 ($0.16 per share) in the second quarter compared to $3,248,047 ($0.13 per share) in the second quarter of 2004.
- Net earnings increased 20 percent in the second quarter to $1,004,410 ($0.02 per share) from $838,123 during the second quarter 2004.
- Commenced summer drilling program at Bigstone, Alberta with two drilling rigs operating. One well has been drilled and an additional 17 locations are in various stages of drilling or preparation for drilling.
- Increased production at Bigstone from 1,200 boe/d to 1,550 boe/d, up 29 percent since February 1, 2005.
- Currently in the field equipping and tying in three standing cased wells under the Company's Development Joint Venture.
- Commenced drilling on the first of four deep, high impact wells under the Company's Exploration Joint Venture.

Operational and Financial Information

	Three Months Ended June 30			Six Months Ended June 30		
	2005	2004	% Change	**2005**	2004	% Change
Average Daily Production						
Natural gas (mcf/d)	**19,961**	5,943	236	**18,429**	5,626	228
Crude oil (bbl/d)	**591**	684	(14)	**652**	559	17
Natural gas liquids (bbl/d)	**274**	42	552	**217**	43	405
Total (boe/d)	**4,192**	1,716	144	**3,941**	1,540	156
Financial Highlights ($)						
Petroleum and natural gas revenue	**17,335,359**	5,859,503	196	**31,313,314**	10,784,238	190
Per boe	**45.45**	37.53	21	**43.91**	38.47	14
Cash flow from operations	**7,936,766**	3,248,047	144	**13,894,988**	5,819,944	139
Per boe	**20.81**	20.80	-	**19.48**	20.76	(6)
Per share – basic and diluted	**0.16**	0.13	23	**0.28**	0.23	22
Net earnings (loss)	**1,004,410**	838,123	**20**	**(937,862)**	1,777,196	-
Per boe	**2.63**	5.37	**(51)**	**(1.33)**	6.33	-
Per share – basic and diluted	0.02	0.03	**(33)**	**(0.02)**	0.07	-
Capital expenditures	**7,072,869**	6,361,075	**11**	**15,858,878**	11,497,004	38

	June 30 2005	December 31 2004	% Change
Debt plus working capital deficit	**68,711,200**	61,274,113	12
Total assets	**196,313,969**	171,946,974	14
Shares outstanding			
Basic	**50,584,991**	47,703,775	6
Diluted	**53,274,691**	49,598,858	7

Message to Shareholders

In the second quarter, Delphi finalized activity from the active winter drilling season and commenced licensing operations for the upcoming drilling, completion and tie-in programs underway at Bigstone, Alberta and in the Grande Prairie region. Although the early breakup and wet weather conditions restricted activity in the field, Delphi completed several compressor installations and upgrades and infrastructure optimization projects at Bigstone, Alberta. The Company achieved production of more than 4,400 boe/d for April with production declining the remainder of the quarter due to the inability to get back into the field until late in the second quarter.

The Company's production increased 144 percent to 4,192 boe/d in the second quarter of 2005, compared to 1,716 in the second quarter of 2004. For the six months ended June 30, 2005, Delphi has produced an average of 3,941 boe/d versus 1,540 boe/d in 2004. The Company's current production is approximately 4,300 boe/d.

OPERATIONS REVIEW

In the second quarter of 2005 Delphi drilled two gross (0.4 net) wells with a 100 percent success rate. The Company continues to focus its operations in North West Alberta, East Central Alberta and North East British Columbia.

North West Alberta

A six well infill drilling program commenced with the spudding of the Bigstone 2-18 on July 14 in the Bigstone Field. This first well, where Delphi is the operator with a 100 percent working interest has reached total depth in the base of the Cretaceous. Three intervals appear productive based on electric log and pressure data obtained during the drilling operation. Completion operations are currently underway and a second drilling rig has recently been moved to the field to expedite the drilling program. Delphi has identified an additional 11 infill locations. Work is in progress to license these wells for an extended summer and winter drilling program which could result in up to 17 wells being drilled in this area of the field.

Delphi also has an 18 to 100 percent working interest in 9,440 net acres of undeveloped land at Bigstone. One of the three wells drilled during the first quarter, the Placid 8-31, where Delphi has an 18 percent working interest, had its first full month of production in April and averaged 2.5 mmcf/d gross from two Cretaceous intervals. The other two wells will be completed and tied-in during the fourth quarter when surface access is available. One of these wells, the Berland River 3-32, has similar log characteristics to the Placid 8-31. In addition to the previously mentioned infill drilling program, Delphi has identified an additional six locations on high working interest (55 percent to 100 percent) acreage in the immediate area and is in the process of obtaining the necessary regulatory approvals to execute a winter drilling program to exploit the identified multi-zone sweet gas potential.

Optimization of the existing production continued into the second quarter with the installation/upgrade of five booster compressors, nine plunger lift systems, and a re-activation increasing on-time and production rates. Due to a wet spring much of this work was postponed until late June but the results are clearly evident with an average July production rate of 1,550 boe/d and a July exit rate approaching 1,600 boe/d. These volumes are up significantly from the 1,200 boe/d the property was producing when Delphi acquired the field on February 1, 2005. In addition to the drilling and optimization work already discussed, Delphi has identified six to eight well optimization and tie-in projects that will be executed during the third and fourth quarters as surface access permits.

In the Berland River area, Delphi is completing the technical evaluation on 12 additional locations prospective for multi-zone sweet gas targets. This potential is on lower working interest lands (5 to 23 percent) and Delphi is evaluating drilling these wells at its present working interest or trading the rights for similar opportunities with a higher working interest in lands contiguous to our Bigstone position.

Fontas, North West Alberta

During the second quarter Delphi and its partners followed up the successful winter drilling program by continuing to optimize the producing wells, gathering system, and facilities at Fontas with a capital expenditure of $0.8 million. Production levels exiting the second quarter were 640 boe/d net to Delphi. The Fontas working interest owners are currently generating plans for the 2005/2006 winter program and Delphi anticipates a program similar in terms of capital and opportunities as this past drilling season.

East Central Alberta

Although the majority of Delphi's 2005 capital program has been devoted to the higher netback gas properties in North West Alberta and North East British Columbia, the strengthening of product prices has warranted reactivation/optimization projects in East Central Alberta. Delphi has either tied-in or re-activated fifteen wells during the second quarter for a capital expenditure of $0.5 million. Based on the current success in this area, Delphi will continue to deploy capital to these types of projects and has identified an additional 15 to 20 reactivation/optimization candidates, some of which are currently being executed. In addition, several of the previously identified drilling opportunities are being re-evaluated for possible acceleration into the third quarter.

North East British Columbia

As the majority of the Delphi properties in North East British Columbia are accessible only during the winter, the second quarter operational activities were limited to minor gathering system optimization and maintenance and the tie-in of one standing well. In addition, Delphi entered into a joint venture that involved the tie-in of a standing Slave Point well and the formation of an Area of Mutual Interest that covers approximately 35,000 acres which has the potential to become a future core area. Total capital expenditures for the North East British Columbia properties were $3.3 million with the majority of the funding directed to the joint venture.

Delphi has committed to its 20 percent working interest share in two Jean Marie development wells that will be drilled in the Missile area as soon as the weather conditions permit access to the drill site. The drill site is adjacent to an all weather road with the first well expected to be spud in the second half of August. Proximity to infrastructure ensures these wells will be brought on production in a timely manner.

In addition, Delphi is preparing its 2005/2006 winter program and has identified 15 development/step-out drilling locations (5.8 net) and seven tie-in opportunities. The tie-in opportunities are projects that were stranded due to the early break-up last winter and represent approximately 325 boe/d to Delphi's working interest. Several of these opportunities already have the regulatory approvals in place and Delphi is working towards having the remainder of approvals completed by mid-October.

2005 Development Joint Venture, North West Alberta

Progress continues on the Development Joint Venture that was negotiated as part of the Bigstone acquisition. Under the terms of this arrangement, Delphi has agreed to re-enter and complete or abandon 26 standing cased wells in order to earn a 100 percent working interest in the well and the lands subject to a 15 percent convertible overriding royalty (which the Farmor may convert to a 50 percent working interest). The uncharacteristically wet spring has delayed some of the re-entry and tie-in projects, however, Delphi is currently in the field equipping and tying in three wells that should be on production during the August to September timeframe. Anticipated rates from these three wells net to Delphi's working interest is expected to be approximately 200 boe/d. Capital expenditures associated with the evaluation and the ongoing equipping of several wells during the second quarter was $0.4 million.

Of the remaining 23 wells; four are either waiting on access or approvals prior to proceeding with the re-entry/tie-in operations, five are still being evaluated for potential and thirteen have either been turned back to the Farmor or scheduled for plugging and abandonment. The four wells waiting on access will probably not be brought online until the fourth quarter of 2005 or the first quarter of 2006 and represent 225 to 450 boe/d to Delphi's working interest.

2005 Exploration Joint Venture, North West Alberta – North East British Columbia

The 2005 Exploration Joint Venture kicked off with the spudding of the Ferrier prospect on July 21. This is the first of four high impact exploration wells under the joint venture program. The general terms in this joint venture consist of Delphi paying 100 percent of the drilling and completion (or abandon) costs and earning a 60 percent working interest in the prospect lands and wellbore. In the three deeper wells, Delphi has taken on additional partners to mitigate its capital exposure.

The Ferrier prospect, defined on 3D seismic, is a 3,300 metre test targeting gas condensate in the Banff formation. Delphi will earn an 11 percent working interest in this prospect. If successful, production could be brought online during the fourth quarter. Banff producers on trend typically have initial production rates from 10 to 20 mmcf/d and many have estimated ultimate recoveries in excess of 20 bcf/well.

The Valhalla prospect is a 3,400 metre test targeting gas condensate in the Wabamun formation. Delphi will operate the drilling of this well and earn a 36 percent working interest in this prospect. The surface location has been built and a rig is expected to move to location during September. As with the Ferrier prospect a successful well could begin producing as early as the fourth quarter of 2005. Wabamun producers on trend typically have initial production rates of between 8 to 10 mmcf/d with estimated ultimate recoveries of 10 bcf/well.

The Cutbank prospect is a 2,300 metre test targeting gas condensate in several Cretaceous aged formations. Delphi will earn a 60 percent working interest in the well and surrounding lands. Our partner, a senior oil and gas company with extensive experience in the area, is currently licensing the location and anticipates moving a rig on site in mid-October. The estimated time to drill the well is 30 to 45 days, which means a successful test would begin production in the first quarter of 2006. It is not uncommon for Cretaceous producers along this trend to have initial production rates in the range of 3 to 5 mmcf/d with estimated ultimate recoveries of 3 to 5 bcf/well.

The Brazeau prospect is a 3,900 metre test targeting gas condensate in the Nisku formation. Delphi will operate the drilling of this well and earn a 36 percent working interest in this prospect. Delphi is in the process of obtaining the necessary regulatory approvals to drill the well and anticipates moving a rig on location in November. If successful, initial production is expected in the first quarter of 2006. Many of the Nisku producers along this trend have initial production rates in excess of 10 mmcf/d with estimated ultimate recoveries in excess of 30 bcf/well.

Personnel

Frank Lowe, Vice President, Production has resigned as an officer of the Company. The Delphi management team thanks Mr. Lowe for his role in helping Delphi achieve production increases over the past year.

FINANCIAL REVIEW

Delphi's operating performance has translated into record financial results including cash flow from operations of $7.9 million ($0.16 per share) in the second quarter of 2005 and $13.9 million ($0.28 per share) for the first six months of 2005. This represents an increase of 144 percent and 139 percent over the comparable periods in 2004. Net earnings for the second quarter were $1.0 million or $0.02 per share and a net loss of $0.9 million or $0.02 per share for the six months ended June 30, 2005. The loss for the six month period is attributable to the unrealized loss on risk management activities of $1.4 million.

Delphi invested capital of $7.1 million during the second quarter, primarily completing projects started late in the first quarter and $15.9 million in the first six months of 2005. With cash flow from operations in excess of capital programs in the second quarter, the Company reduced its debt plus working capital deficiency by $2.2 million in the second quarter to $68.7 million. Delphi's credit facility is presently under review with an increase expected. The Company expects to fund its remaining 2005 capital program out of cash flow from operations and available credit lines.

OUTLOOK

Delphi's capital program, which is focused on low risk development drilling at Bigstone, Alberta and recompletion, tie-in, and optimization projects in all core areas is well underway. An unusually wet second quarter, delaying activity in the field four to six weeks, reduced second quarter production levels, but with two rigs active in Bigstone and the start-up of numerous other projects, an exit rate for 2005 of 5,800 to 6,300 boe/d continues to be achievable. In addition, drilling has commenced on the first of 4 high impact exploration wells under the Company's Exploration Joint Venture. Delphi plans to spend approximately $20 million to $25 million, drilling up to 15 wells throughout the remainder of the year. The Company estimates it has approximately 400 boe/d of production awaiting tie-in of which approximately 200 boe/d in North West Alberta is in the process of being tied in and should be on-stream in the third quarter. With current commodity prices and production levels, the Company expects to fund its remaining capital program from cash flow from operations with incremental cash flow being applied to the Company's bank debt as planned. Delphi has begun drilling its significant inventory of opportunities and looks forward to reporting continued growth in production and financial results.

On behalf of the Board,

David J. Reid
President and Chief Executive Officer
August 10, 2005

Management's Discussion and Analysis

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 six months ended June 30, 2005 and 2004 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, 2004 and 2003 included in the Company's 2004 Annual Report.

NON GAAP Measures. 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.

Cash flow from operations before change in non-cash working capital is not a recognized measure under Canadian generally accepted accounting principles. Management uses cash flow from operations before change in non-cash working capital 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. The Company's reconciliation between net earnings (loss) and cash flow from operations before change in non-cash working capital is disclosed subsequently in management's discussion and analysis. Cash flow from operations before change in non-cash working capital has been defined by the Company as net earnings (loss) plus the addback of non-cash items (depletion, depreciation and accretion, stock-based compensation, future income taxes and unrealized risk management activities) and excludes the change in non-cash working capital related to operating activities. Delphi's determination of cash flow from operations before change in non-cash working capital may not be comparable to that reported by other companies. The Company also presents cash flow from operations before change in non-cash working capital per share whereby amounts per share are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

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.

The discussion and analysis has been prepared as of August 2, 2005.

Production

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2005	2004		**2005**	2004	
Natural gas (mcf/d)	**19,961**	5,943	236	**18,429**	5,626	228
Crude oil (bbl/d)	**591**	684	(14)	**652**	559	17
Natural gas liquids (bbl/d)	**274**	42	552	**217**	43	405
Total (boe/d)	**4,192**	1,716	144	**3,941**	1,540	156

Production for the three months ended June 30, 2005 averaged 4,192 boe/d comprised of 19,961 mcf/d of natural gas, 591 bbls/d of crude oil and 274 bbls/d of natural gas liquids. Average production volumes increased 144 percent on a quarter-over-quarter basis in 2005 compared to 2004 primarily as a result of capital programs undertaken in the first six months of 2005 and the recent corporate acquisition of Tercero Energy Inc. (Tercero) and the liquids rich natural gas property acquisition at Bigstone, Alberta. During the quarter, the Company achieved 4,400 boe/d for April upon the completion of numerous first quarter and early second quarter projects with production declining the remainder of the quarter as a result of a prolonged spring break-up and wet weather conditions hampering field activity.

Natural gas production increased 236 percent during the second quarter of 2005 compared to the same quarter of 2004, primarily as a result of increased production from North East British Columbia associated with the Tercero acquisition, acquired natural gas production at Bigstone, Alberta, the installation of a refrigeration facility at Fontas, Alberta and capital programs completed in the first six months of 2005.

Crude oil production was 14 percent lower for the three months ended June 30, 2005 averaging 591 bbls/d compared to 684 bbls/d for the comparative quarter of 2004. The decrease is due to normal declines and a prolonged spring break-up and wet weather conditions which restricted surface access and hence the Company's ability to service wells, which had gone off-stream in East Central Alberta, until late in the second quarter. The Company continues to optimize its East Central assets and with continued high oil commodity prices, despite historically wide differentials, reactivate shut-in heavy oil wells.

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

Commodity Prices and Risk Management

Benchmark Prices

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2005	2004		**2005**	2004	
Natural gas						
New York Mercantile Exchange (US $/mmbtu)	**6.76**	5.97	**13**	**6.53**	5.83	**12**
AECO (CDN $/mcf)	**7.35**	6.99	**5**	**7.11**	6.70	**6**
Crude oil						
West Texas Intermediate (US $/bbl)	**53.17**	38.32	**39**	**51.51**	36.73	**40**
Edmonton Light (CDN $/bbl)	**65.79**	50.60	**30**	**63.73**	48.09	**33**
Foreign exchange rate						
US to Canadian dollar	**0.8039**	0.7358	**9**	**0.8093**	0.7472	**8**
Canadian to US dollar	**1.2439**	1.3590	**(8)**	**1.2355**	1.3383	**(8)**

Natural Gas

United States natural gas prices are commonly referenced to the New York Mercantile Exchange Henry Hub, Louisiana (NYMEX) index price while Canadian natural gas prices are typically referenced to the AECO Hub in Alberta (AECO). Natural gas prices are influenced more by North American supply and demand than global fundamentals. During the three month period ended June 30, 2005 AECO natural gas price averaged $7.35/mcf compared to $6.99/mcf for the same period in 2004. In the first six months of 2005, the AECO natural gas price averaged $7.11/mcf compared to $6.70/mcf in 2004. Delphi expects gas prices to increase during the third and fourth quarters of 2005 and to exceed 2004 levels.

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 Canadian/US dollar exchange rate. During the three and six months ended June 30, 2005, WTI averaged US $53.17/bbl and $51.51/bbl compared to US $38.32/bbl and $36.73/bbl in 2004. Crude oil prices continued to show sustained strength during the second quarter of 2005 due to increasing demand for gasoline and market uncertainty whether this demand could be satisfied due to a lack of refining capacity.

During the three and six months ended June 30, 2005, Canadian crude oil prices were negatively affected as a result of the strengthening Canadian dollar relative to its US counterpart averaging CDN/US $1.24 compared to CDN/US $1.36 and CDN/US $1.34 during the comparable periods in 2004, respectively.

Heavy oil differentials continued to be above historical averages throughout the three and six months ended June 30, 2005. Differentials began widening in the fourth quarter of 2004, ranging between $20.00 and $25.00 per barrel and have continued to remain around $25.00 or higher during the three months and six months ended June 30, 2005, wider than recent historical averages. The average differential for the second quarter of 2005 was $24.82 per barrel.

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.

The Company is required to mark-to-market its outstanding financial fixed price 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 recorded to income. The fair values of these instruments are based on approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding at June 30, 2005 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. As a result, the Company incurred an unrealized non-cash gain on risk management activities for the three months ended June 30, 2005 of $1,242,150 and an unrealized non-cash loss of $1,444,684 for the six months ended June 30, 2005.

During the three and six month period ended June 30, 2005, Delphi recorded a realized loss on commodity contracts relating to both financial and physical contracts of $560,851 and $370,670, respectively.

Realized Sales Prices

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2005	2004		**2005**	2004	
Natural gas ($/mcf)	**7.90**	6.50	22	**7.50**	6.66	13
Gain/(loss) on risk management activities ($/mcf)	**(0.10)**	-		**0.06**	-	
Realized gas price ($/mcf)	**7.80**	6.50	20	**7.56**	6.66	14
Crude oil ($/bbl)	**45.10**	36.93	22	**41.42**	37.15	11
Gain/(loss) on risk management activities ($/bbl)	**(6.98)**	(1.27)	450	**(4.94)**	(0.78)	533
Realized oil price ($/bbl)	**38.13**	35.66	7	**36.48**	36.37	-
Natural gas liquids ($/bbl)	**45.15**	32.77	38	**45.60**	33.91	35
Total ($/boe)	**45.45**	37.53	21	**43.91**	38.47	14

The Company's average realized sales price per boe increased 21 percent in the second quarter of 2005 versus the comparative period of 2004. The average crude oil sales price before hedging losses increased 22 percent, consistent with the upward trend of the benchmark WTI over the same period offset by the strengthening of the Canadian dollar and widening light-heavy differentials. The realized sales price for crude oil in the second quarter of 2005, after hedging losses, increased 7 percent versus the comparative quarter of 2004. 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 21 percent of the Company's production being priced at Chicago from sales on the Alliance Pipeline. Realized natural gas prices increased 20 percent in the second quarter of 2005 compared to an increase in AECO of only 5 percent for the same period. Realized natural gas liquids prices have increased significantly due to the increase in the price received for condensate.

Revenue

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Natural gas	**14,347,074**	3,516,407	308	**25,007,762**	6,815,331	267
Crude oil	**2,424,764**	2,298,077	6	**4,886,710**	3,779,603	29
Natural gas liquids	**1,124,372**	123,875	808	**1,789,512**	268,160	567
Realized risk management activities	**(560,851)**	(78,856)	611	**(370,670)**	(78,856)	370
Total	**17,335,359**	5,859,503	196	**31,313,314**	10,784,238	190

Quarter-over-quarter total revenue increased $11,475,856 or 196 percent in 2005 as compared to 2004 primarily due to the acquisition of Tercero Energy Inc. and the natural gas and natural gas liquids producing property in Bigstone. The increase in revenue can be attributed to a 21 percent increase in the Company's average realized sales price and a 144 percent increase in production volumes. Revenue for the six months ended June 30, 2005 increased 190 percent due to a 14 percent increase in the Company's average realized sales price and a 156 percent increase in production. Of the increase in total revenue, 89 percent is attributable to natural gas sales which increased 267 percent over 2004.

Royalties

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Crown	**3,676,863**	863,620	326	**6,240,340**	1,578,238	296
Freehold and gross overriding	**288,785**	227,210	27	**594,757**	376,187	58
Total	**3,965,648**	1,090,830	264	**6,835,097**	1,954,425	250
Royalty credits	**(447,886)**	(571,315)	(22)	**(858,399)**	(863,371)	(1)
Net	**3,517,762**	519,515	577	**5,976,698**	1,091,054	448
Per boe	**9.22**	3.34	176	**8.38**	3.89	115
Percent of total revenue	**20.3%**	8.9%	128	**19.1%**	10.1%	89

The Company pays royalties to provincial governments, freeholders, which can be individuals or companies, and other oil and gas operators, who own surface or mineral rights. The Company also receives the Alberta Royalty Tax Credit (ARTC), a tax rebate received from the Alberta government for eligible crown royalties paid in the year. Royalty rates are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to price increases or due to an increase in production volumes on a well by well basis. During the second quarter of 2005, total royalties increased 264 percent compared to 2004, as a result of increased production of natural gas, higher natural gas prices and increased oil and liquids production quarter-over-quarter. Royalty credits in the second quarter of 2005 of $447,886 are lower than the comparative quarter of 2004 due to a significant credit for gas cost allowance related to prior periods received in the second quarter of 2004. Royalties as a percentage of revenue increased 128 percent for the quarter ended June 30, 2005 compared to 2004, primarily due to properties acquired having royalty rates consistent with industry norms, however, higher than the Company's average royalty rate otherwise. For the remainder of 2005, the Company expects royalty rates to be approximately 19 to 20 percent of gross oil and gas revenue.

Operating Expenses

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Total	**3,208,822**	1,264,008	154	**5,851,821**	2,279,831	157
Per boe	**8.41**	8.10	4	**8.21**	8.13	1
Percent of total revenue	**18.5%**	21.6%	(14)	**18.7%**	21.1%	(11)

Operating expenses on a per boe basis for the three and six months ended June 30, 2005 increased 4 percent and 1 percent over the comparative prior periods, respectively. The second quarter operating costs were adversely affected by approximately $255,000 or $0.67 per boe relating to facility equalization costs from prior years associated with North East British Columbia production and operating costs associated with the Company's oil producing properties in East Central Alberta. Delphi plans to continue with field optimization initiatives and expects operating costs to trend downwards for the remainder of the year as low operating cost production at Bigstone (less than $4.00/boe) becomes a greater component of the Company's production.

Transportation Expenses

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Total	**1,284,370**	261,423	391	**2,251,510**	424,713	430
Per boe	**3.37**	1.67	102	**3.16**	1.52	108
Percent of total revenue	**7.4%**	4.5%	64	**7.2%**	3.9%	85

Transportation costs are higher by $1,022,947, an increase of 391 percent, in the three months ended June 30, 2005 compared to the same period of 2004, primarily due to a 144 percent increase in production volumes in 2005. On a per boe basis, transportation costs increased 102 percent over 2004 primarily due to the transportation costs associated with natural gas production in North East British Columbia and the natural gas production from the Bigstone area.

In British Columbia, there is an infrastructure 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.

Approximately 65 percent in the second quarter of 2005 and 75 percent in the six months ended June 30, 2005 of the Company's natural gas production from the Bigstone area is 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 and Stock-based Compensation

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
General and administrative costs	**975,280**	755,179	29	**2,203,157**	1,399,980	57
Overhead recoveries	**(122,802)**	(165,329)	(26)	**(254,878)**	(232,445)	10
Salary reallocations	**(287,466)**	(131,577)	118	**(648,526)**	(288,653)	125
Net	**565,012**	458,273	23	**1,299,753**	878,882	48
Per boe	**1.48**	2.93	(49)	**1.82**	3.14	(42)
Stock-based compensation expense	**407,747**	191,668	113	**982,550**	169,706	479
Per boe	**1.07**	1.23	(13)	**1.38**	0.61	126

On a gross basis, general and administrative ("G&A") expense for the three and six month period increased 29 percent and 57 percent commensurate with increased staffing and activity levels associated with the Company's growth from corporate and property acquisitions and capital program. The Company anticipates monthly G&A costs to remain relatively stable for the remainder of the year on a gross basis and decrease on a per boe basis as additional production is brought on-stream. Salary reallocations have increased by 118 percent due to operating oil and gas properties and increased technical staff efforts toward the Company's capital program.

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 are estimated at the date of grant using the Black-Scholes option pricing model. The non-cash compensation expense for the three and six months ended June 30, 2005 increased 113 percent and 479 percent. The increase is a function of additional options being granted to new staff to facilitate the significant growth of the Company, with one-third of the options vesting immediately pursuant to the Company's stock option plan and a higher average fair value option price.

Interest

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Financing	**673,008**	119,812	462	**1,833,757**	243,101	654
Other charges	**128,983**	2,906	4,339	**150,188**	39,433	281
Interest income	**(8,585)**	(22,464)	(62)	**(54,271)**	(23,484)	131
Total	**793,406**	100,254	691	**1,929,674**	259,050	645
Per boe	**2.08**	0.64	225	**2.71**	0.92	195

Interest expense on a gross and per boe basis has increased commensurate with higher average debt levels and $10,000,000 mezzanine debt outstanding from December 8, 2004 to February 23, 2005 with an effective interest rate of 15.75 percent used to fund the growth in the Company's operations and to finance the significant property acquisition during the first quarter of 2005. Other charges primarily relate to the Part XII.6 tax associated with the Company's flow-through obligation.

Depletion, Depreciation and Accretion

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Depletion and depreciation	**6,626,676**	1,957,055	239	**11,924,276**	3,491,825	241
Accretion expense	**130,970**	63,775	105	**226,203**	127,550	77
Total	**6,757,646**	2,020,830	234	**12,150,479**	3,619,375	236
Per boe	**17.72**	12.94	37	**17.04**	12.92	32

Depletion, depreciation and accretion per boe increased 37 percent and 32 percent, respectively, for the three and six months ended June 30, 2005. This increase is attributable to higher cost proved reserve additions in the year and a larger capital base from acquisitions and increased spending levels. The increase in total depletion, depreciation and accretion versus the comparable 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 3 to 20 years. The Company uses a credit adjusted risk-free rate of 8 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 six months ended June 30, 2005 was $130,970 and $226,203 representing a 105 percent and 77 percent increase over comparable periods. The increase is due to increased drilling and the major acquisitions at the end of 2004 and during the first quarter of 2005.

Taxes

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Current	**29,221**	7,983	266	**108,870**	30,764	254
Future	**1,009,113**	197,426	411	**255,137**	253,667	1
Total	**1,038,334**	205,409	405	**364,007**	284,431	28

Current tax for the three months and six months ended June 30, 2005 consists of Federal Large Corporations Tax. Future income tax of $1,009,113 was recorded for the three months ended June 30, 2005 versus $255,137 for the six months ended June 30, 2005. Future income taxes on a year to date basis are lower than the future taxes recorded in the second quarter of 2005 due to a reduction of future income taxes recorded in the first quarter of 2005 associated with the net loss in the first quarter of 2005.

Cash Flow from Operations Before Change in Non-Cash Working Capital

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Net earnings (loss)	**1,004,410**	838,123	20	**(937,862)**	1,777,196	-
Non-cash items						
Depletion, depreciation and accretion	**6,757,646**	2,020,830	234	**12,150,479**	3,619,375	236
Unrealized loss/(gain) on risk management activities	**(1,242,150)**	-	-	**1,444,684**	-	-
Stock-based compensation expense	**407,747**	191,668	113	**982,550**	169,706	479
Future income taxes	**1,009,113**	197,426	411	**255,137**	253,667	1
Total	**7,936,766**	3,248,047	144	**13,894,988**	5,819,944	139

For the three and six months ended June 30, 2005 cash flow from operations before change in non-cash working capital was $7,936,766 ($0.16 per basic share) and $13,894,988 ($0.28 per basic share) compared to $3,248,047 ($0.13 per basic share) and $5,819,944 ($0.23 per basic share). The increase in cash flow reflects the effects of increased revenues resulting primarily from higher production volumes and increased realized commodity prices.

Net Earnings (Loss)

For the three and six months ended June 30, 2005, Delphi recorded net earnings of $1,004,410 and a net loss of $937,862, respectively. The loss is primarily attributable to non-cash charges such as the unrealized loss on risk management activities and stock-based compensation expense.

Netback Analysis

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
Barrels of oil equivalent ($/boe)	**2005**	2004		**2005**	2004	
Realized sales price	**45.45**	37.53	21	**43.91**	38.47	14
Royalties, net of ARTC	**9.22**	3.34	176	**8.38**	3.89	115
Operating expenses	**8.41**	8.10	4	**8.21**	8.13	1
Transportation	**3.37**	1.67	102	**3.16**	1.52	108
Operating netback	**24.45**	24.42	-	**24.16**	24.93	(3)
General and administrative	**1.48**	2.93	(49)	**1.82**	3.14	(42)
Interest	**2.08**	0.64	225	**2.71**	0.92	195
Current taxes	**0.08**	0.05	60	**0.15**	0.11	36
Cash netback	**20.81**	20.80	-	**19.48**	20.76	(6)
Unrealized loss (gain) on risk management activities	**(3.26)**	-	-	**2.03**	-	-
Stock-based compensation expense	**1.07**	1.23	(13)	**1.38**	0.61	126
Depletion, depreciation and accretion	**17.72**	12.94	37	**17.04**	12.92	32
Future income taxes (recovery)	**2.65**	1.26	110	**0.36**	0.90	(60)
Net earnings (loss)	**2.63**	5.37	(51)	**(1.33)**	6.33	-

Drilling Results

	Three Months Ended June 30, 2005		Six Months Ended June 30, 2005	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**2**	**0.4**	**19**	**3.5**
Oil wells	**-**	**-**	**-**	**-**
Dry holes	**-**	**-**	**4**	**1.1**
Total wells	**2**	**0.4**	**23**	**4.6**
Success rate	**100%**		**83%**	

Capital Invested

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($)	**2005**	2004		**2005**	2004	
Land	**(48,126)**	129,305	-	**135,248**	485,703	(72)
Seismic	**81,941**	94,375	(13)	**59,999**	98,117	(39)
Drilling and completions	**1,521,650**	3,226,362	(53)	**7,276,723**	4,755,397	53
Equipping and facilities	**5,250,498**	2,690,392	95	**7,728,784**	5,723,044	35
Property acquisition	**23,640**	633,195	(96)	**51,273,182**	633,195	7,998
Capitalized expenses	**259,174**	161,359	61	**596,119**	314,812	89
Other	**7,732**	59,282	(87)	**62,005**	119,931	(48)
Capital invested	**7,096,509**	6,994,270	1	**67,132,060**	12,130,199	453
Asset retirement costs	**-**	(15,352)	-	**1,398,093**	32,674	4,179
Total capital invested	**7,096,509**	6,978,918	2	**68,530,153**	12,162,873	463

In the second quarter of 2005, the Company's capital program, excluding property acquisitions, was $7,072,869, 11 percent higher than the previous year's capital expenditures of $6,361,075. The Company participated in the drilling of 2 gross (0.4 net) wells for a 100 percent success rate early in the second quarter. A significant portion of the capital expenditures incurred in the second quarter were directed to the completion of projects started late in the first quarter, particularly at Bigstone where 3 compressor optimization projects were completed, in North East British Columbia with the equip and tie-in of a natural gas well, completion of a water handling facility, and a compressor upgrade and in North West Alberta involving recompletion and re-entry work associated with the Company's development joint venture. Later in the second quarter, the Company was able to continue with activity at Bigstone with the installation of two more compressors and various plunger lifts to reduce downtime and optimize the gathering system and production. In preparation of the Company's summer drilling program at Bigstone starting in the third quarter, the Company incurred survey and licensing costs once the wet weather conditions improved and surface access was available. In East Central Alberta, the Company continued its optimization efforts including the reactivation of numerous heavy oil wells supported by high commodity prices and the equip and tie-in of a natural gas well.

On February 1, 2005, the Company acquired liquids rich natural gas properties at Bigstone in North West Alberta for cash consideration of $51,273,182. The acquisition adds long life natural gas production to this core area of the Company. On January 31, 2005, the Company disposed of non-core properties in Alberta for proceeds on disposition of $5,862,917.

The present value of future asset retirement costs associated with the acquisition of Bigstone and drilling operations, offset by obligations settled due to the dispositions was $1,398,093.

Liquidity and Capital Resources

Funding

	Three months ended June 30, 2005	Six Months ended June 30, 2005
Sources ($)		
Cash flow from operations before change in non-cash working capital	**7,936,766**	**13,894,988**
Issue of flow-through common shares, net	**-**	**11,143,926**
Exercise of stock options	**110,915**	**237,819**
Proceeds on the disposition of properties	**-**	**5,862,917**
Cash held in trust	**-**	**30,000,007**
Cash on hand	**184,396**	**1,891,962**
Change in non-cash working capital	**3,864,432**	**600,441**
	12,096,509	**63,632,060**
Uses ($)		
Property, plant and equipment additions	**7,072,869**	**15,858,878**
Property acquisition	**23,640**	**51,273,182**
Repayment of mezzanine debt	**-**	**10,000,000**
	7,096,509	**77,132,060**
Increase / (decrease) in bank debt	**(5,000,000)**	**13,500,000**

For the three months ended June 30, 2005, the Company had sources of cash totaling $12,096,509 and uses of cash of $7,096,509 towards capital investments, resulting in a decrease in bank debt of $5,000,000. The Company expects to fund the remainder of its 2005 capital program primarily through internally generated cash flow.

Share Capital

The following table summarizes the common shares issued during the six months ended June 30, 2005.

	Number of common shares
Balance, December 31, 2004	**47,703,775**
Issue of flow-through common shares for cash	**2,727,500**
Exercise of stock options for cash	**153,716**
Balance June 30, 2005	**50,584,991**

The common shares of Delphi trade on the TSX under the symbol DEE. The following table summarizes outstanding share data for the three and six month period ended June 30, 2005.

Weighted Average Common Shares	Three months ended June 30, 2005	Six months ended June 30, 2005
Basic	**50,540,265**	**49,163,794**
Diluted	**50,863,829**	**49,487,358**
Trading Statistics		
High	**3.75**	**4.10**
Low	**2.63**	**2.63**
Close	**3.45**	**3.45**
Average daily, volume	**134,762**	**136,741**

As at August 2, 2005, the Company had 50,594,991 common shares outstanding and 2,829,700 stock options outstanding.

Bank Debt plus Working Capital

At June 30, 2005, the Company had $60,900,000 outstanding on its credit facility and a working capital deficit of $6,366,516, excluding the accrued liability of $1,444,684 relating to the unrealized loss on risk management activities, for total debt plus working capital deficit of $67,266,516, down from $68,217,688 at the end of the first quarter of 2005. The Company's anticipated cash flow from operations before change in non-cash working capital will be sufficient to meet the current working capital deficit. The capital intensive nature of the Company's industry will result in a working capital deficiency, however, the Company will maintain total debt plus working capital deficit below the Company's credit facility. At June 30, 2005 the Company had a credit facility of $79,500,000. This credit facility is currently being reviewed. The Company expects to receive an increase in its credit facility upon completion of the review.

Selected Quarterly Information

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

	Jun. 30 2005	Mar. 31 2005	Dec. 31 2004	Sept. 30 2004	June 30 2004	Mar. 31 2004	Dec. 31 2003	Sept. 30 2003
Production								
Oil and NGLs (bbl/d)	**865**	872	879	857	726	479	520	282
Natural gas (mcf/d)	**19,961**	16,880	6,678	5,353	5,943	5,308	6,081	5,779
Barrels of oil equivalent (boe/d)	**4,192**	3,685	1,991	1,749	1,716	1,364	1,534	1,245
Financial								
($000s, except as noted)								
Petroleum and natural gas revenue	**17,335**	13,978	7,457	6,233	5,860	4,925	4,470	3,893
Cash flow	**7,937**	5,958	2,747	3,557	3,248	2,572	1,925	1,442
Per share basic & diluted	**0.16**	0.12	0.09	0.14	0.13	0.10	0.08	0.06
Net earnings (loss)	**1,004**	(1,942)	(679)	855	838	939	1,042	(209)
Per share basic & diluted	**0.02**	(0.04)	(0.02)	0.03	0.03	0.04	0.05	(0.01)
Capital expenditures	**7,097**	60,036	62,084	11,508	6,979	5,136	6,603	8,628
Per unit information								
Natural gas ($/mcf)	**7.80**	7.28	7.20	6.25	6.50	6.83	5.67	6.12
Oil and natural gas liquids ($/bbl)	**40.35**	37.16	37.57	40.03	35.50	37.25	27.09	24.67
Oil equivalent ($/boe)	**45.45**	42.13	40.70	38.73	37.53	39.67	31.67	33.98
Operating netback ($/boe)	**24.45**	23.83	21.45	23.66	24.42	25.57	18.00	16.35

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. The future minimum commitments are as follows:

2005	$ 887,333
2006	2,231,186
2007	2,230,435
2008	2,093,361
2009	2,124,761
2010	2,156,633
2011	1,818,593

The Company also has a lease rental commitment on office premises from 2005 through 2008 which requires annual payments of $87,000.

As at June 30, 2005, the Company had an obligation to incur qualifying exploration expenditures of $8,200,000 to satisfy terms of the flow-through common shares issued during the previous year and an obligation to incur qualifying exploration expenditures of $12,001,000 to satisfy terms of the flow-through common shares issued during the period.

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 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.

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.

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

Time Period	Commodity	Type of Contract	Quantity Contracted	Canadian Price (Per GJ/bbl)
April 2005 – October 2005	Natural Gas	Financial	2,500 GJ/d	$6.31 fixed
April 2005 – October 2005	Natural Gas	Financial	2,000 GJ/d	$6.00 floor/$6.90 ceiling
July 2005 – October 2005	Natural Gas	Physical	1,000 GJ/d	$7.05 fixed
November 2005 – March 2006	Natural Gas	Financial	2,000 GJ/d	$7.79 fixed
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$8.90 ceiling
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$7.50 floor/$9.65 ceiling
July 2005 – September 2005	Crude Oil	Financial	300 bbl/d	$54.66 fixed
October 2005 – December 2005	Crude Oil	Financial	300 bbl/d	$55.01 fixed

As at June 30, 2005, the Company has marked-to-market its financial fixed price contracts resulting in an unrealized loss on risk management activities of $1,444,684 and an obligation of an equivalent amount.

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 appropriate 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 individual's 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.

Guarantees and Off-balance Sheet Arrangements

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

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.
Balance Sheets

		June 30 2005		December 31 2004
Assets		(unaudited)		(audited)
Current assets:				
Cash	$	-	$	1,891,962
Accounts receivable		**11,223,249**		5,675,468
Prepaid expenses and deposits		**1,266,088**		1,297,865
		12,489,337		8,865,295
Cash in trust		-		30,000,007
Property, plant and equipment (Note 3)		**171,724,956**		120,981,996
Goodwill		**12,099,676**		12,099,676
	$	**196,313,969**	$	171,946,974
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$	**18,855,853**	$	12,739,408
Risk management liability (Note 8)		**1,444,684**		-
Mezzanine debt (Note 4)		-		10,000,000
Bank debt (Note 5)		**60,900,000**		47,400,000
		81,200,537		70,139,408
Future income taxes		**11,008,496**		7,646,000
Asset retirement obligations (Note 6)		**6,636,013**		5,011,717
Shareholders' equity:				
Share capital (Note 7)		**96,361,760**		87,943,635
Contributed surplus (Note 7)		**1,911,255**		1,072,444
Retained earnings (deficit)		**(804,092)**		133,770
		97,468,923		89,149,849
	$	**196,313,969**	$	171,946,974

Commitment (Note 9)

See accompanying notes to the financial statements

DELPHI ENERGY CORP.

Statements of Earnings (Loss) (unaudited)

	Three months ended June 30		Six months ended June 30	
	2005	2004	**2005**	2004
Revenue:				
Petroleum and natural gas sales	**$ 17,896,210**	$ 5,938,359	**$ 31,683,984**	$ 10,863,094
Realized gain (loss) on risk management activities	**(560,851)**	(78,856)	**(370,670)**	(78,856)
	17,335,359	5,859,503	**31,313,314**	10,784,238
Unrealized gain (loss) on risk management activities	**1,242,150**	-	**(1,444,684)**	-
Royalties (net of ARTC)	**(3,517,762)**	(519,515)	**(5,976,698)**	(1,091,054)
	15,059,747	5,339,988	**23,891,932**	9,693,184
Expenses:				
Operating	**3,208,822**	1,264,008	**5,851,821**	2,279,831
Transportation	**1,284,370**	261,423	**2,251,510**	424,713
General and administrative	**565,012**	458,273	**1,299,753**	878,882
Stock-based compensation	**407,747**	191,668	**982,550**	169,706
Interest	**793,406**	100,254	**1,929,674**	259,050
Depletion, depreciation and accretion	**6,757,646**	2,020,830	**12,150,479**	3,619,375
	13,017,003	4,296,456	**24,465,787**	7,631,557
Earnings (loss) before taxes	**2,042,744**	1,043,532	**(573,855)**	2,061,627
Taxes:				
Capital	**29,221**	7,983	**108,870**	30,764
Future	**1,009,113**	197,426	**255,137**	253,667
	1,038,334	205,409	**364,007**	284,431
Net earnings (loss)	**$ 1,004,410**	$ 838,123	**$ (937,862)**	$ 1,777,196
Net earnings (loss) per share (Note 7(f))				
Basic and diluted	**$ 0.02**	$ 0.03	**$ (0.02)**	$ 0.07

See accompanying notes to the financial statements

DELPHI ENERGY CORP.

Statements of Retained Earnings (Deficit) (unaudited)

	Three months ended June 30		Six months ended June 30	
	2005	2004	**2005**	2004
Retained earnings (deficit), beginning of period	**$ (1,808,502)**	$ **(879,679)**	**$ 133,770**	$ (1,150,466)
Changes in accounting policies				
Stock-based compensation	**-**	**-**	**-**	(668,286)
Net earnings (loss)	**1,004,410**	**838,123**	**(937,862)**	1,777,196
Retained earnings (deficit), end of period	**$ (804,092)**	$ **(41,556)**	**$ (804,092)**	$ (41,556)

See accompanying notes to the financial statements

DELPHI ENERGY CORP.

Statements of Cash Flows (unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
Cash provided by (used in):				
Operations:				
Net earnings (loss)	**$ 1,004,410**	$ 838,123	**$ (937,862)**	$ 1,777,196
Add non cash items:				
Depletion, depreciation and accretion	**6,757,646**	2,020,830	**12,150,479**	3,619,375
Stock-based compensation	**407,747**	191,668	**982,550**	169,706
Unrealized (gain) loss on risk management activities	**(1,242,150)**	-	**1,444,684**	-
Future taxes	**1,009,113**	197,426	**255,137**	253,667
Funds from operations	**7,936,766**	3,248,047	**13,894,988**	5,819,944
Change in non-cash working capital	**3,620,565**	1,368,033	**(630,076)**	(2,272,444)
	11,557,331	4,616,080	**13,264,912**	3,547,500
Financing:				
Issue of shares, net of issue costs	**110,915**	16,756	**11,381,745**	173,741
Repayment of mezzanine debt	**-**	-	**(10,000,000)**	-
Increase in bank debt	**(5,000,000)**	2,748,197	**13,500,000**	6,379,197
	(4,889,085)	2,764,953	**14,881,745**	6,552,938
Investing:				
Property, plant and equipment additions	**(7,072,869)**	(6,994,270)	**(15,858,878)**	(12,130,199)
Acquisition of properties	**(23,640)**	-	**(51,273,182)**	-
Proceeds on the disposition of properties	**-**	-	**5,862,917**	-
Change in non-cash working capital	**243,867**	(386,763)	**1,230,517**	2,029,761
	(6,852,642)	(7,381,033)	**(60,038,626)**	(10,100,438)
Increase (decrease) in cash and cash equivalents	**(184,396)**	-	**(31,891,969)**	-
Cash and cash equivalents, beginning of period	**184,396**	-	**31,891,969**	-
Cash and cash equivalents, end of period	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 599,604**	$ 177,871	**$ 1,812,855**	$ 323,295
Taxes paid	**$ 135,162**	$ 75,270	**$ 154,811**	$ 81,898

See accompanying notes to the financial statements

DELPHI ENERGY CORP.
Notes to Financial Statements

Six months ended June 30, 2005 and 2004 (unaudited)

The unaudited interim financial statements of Delphi Energy Corp. (the "Company") 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, 2004. Certain comparative figures have been reclassified to conform with current period presentation. 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 from the year ended December 31, 2004.

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 1: BASIS OF PRESENTATION

The financial statements include the accounts of the Company and Tercero Energy Inc. ("Tercero"), which was acquired on December 9, 2004 and amalgamated with the Company on February 1, 2005. The financial statements are stated in Canadian dollars.

Note 2: 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 $51,273,182. The Company paid for the acquisition with cash and increased bank debt.

On December 9, 2004, the Company acquired all of the issued and outstanding shares of Tercero, a private company involved in the exploration, development and production of oil and natural gas, for cash consideration of $42,531,777. The transaction was accounted for using the purchase method. The assets and liabilities have been recorded at their fair values. The accounts of the Company include the results of Tercero, which was amalgamated with the Company on February 1, 2005.

Allocated:

Property and equipment	$	52,391,118
Working capital		2,172,974
Goodwill		9,864,680
Bank debt		(14,950,000)
Asset retirement obligations		(1,011,563)
Future income tax liability		(4,850,122)
	$	43,617,087

Purchase price:		
Cash consideration	$	42,531,777
Transaction costs		1,085,310
	$	43,617,087

Note 3: PROPERTY, PLANT AND EQUIPMENT

June 30, 2005		Cost		Accumulated depletion and depreciation		Net book value
Petroleum and natural gas properties	**$**	**160,934,053**	**$**	**26,252,135**	**$**	**134,681,918**
Production equipment		**41,747,596**		**4,922,852**		**36,824,744**
Furniture, fixtures and office equipment		**466,832**		**248,538**		**218,294**
	$	**203,148,481**	**$**	**31,423,525**	**$**	**171,724,956**

December 31, 2004						
Petroleum and natural gas properties	$	110,009,449	$	17,219,756	$	92,789,693
Production equipment		30,066,969		2,067,725		27,999,244
Furniture, fixtures and office equipment		404,827		211,768		193,059
	$	140,481,245	$	19,499,249	$	120,981,996

As at June 30, 2005, costs in the amount of $24,792,000 (December 31, 2004 - $15,600,000) representing unproved properties were excluded from the depletion calculation and future development costs of $8,442,000 (December 31, 2004 - $7,700,000) have been included in costs subject to depletion.

During the six months ended June 30, 2005, the Company capitalized $596,119 (2004 - $288,853) of general and administrative costs directly related to exploration and development activities.

During the six months ended June 30, 2005, the Company disposed of two non-core properties for total proceeds of $5,862,917.

Note 4: MEZZANINE DEBT

		June 30, 2005		December 31, 2004
Mezzanine debt	**$**	**-**	$	10,000,000

On February 23, 2005, the maturity date of the mezzanine debt, the Company repaid the entire principal balance and interest payable on the mezzanine debt, including the repurchase of the gross overriding royalty, for a total of $10,332,260. The repayment was funded by proceeds on the disposition of properties and bank debt.

Note 5: BANK DEBT

		June 30, 2005		December 31, 2004
Bank debt	**$**	**60,900,000**	$	47,400,000

At June 30, 2005 the Company had drawn $60,900,000 on its banking facility. The Company has a financing commitment with a Canadian chartered bank for a demand loan credit facility of $79,500,000. The facility bears interest at bank prime rate plus 0.75%, payable monthly, and is secured by a $100 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 $13,500,000. A credit-adjusted risk-free rate of 8.0% and an inflation rate of 2.5% was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below.

		Amount
Balance, December 31, 2004	$	5,011,717
Liabilities incurred due to operations		44,217
Liabilities incurred due to acquisitions		1,603,876
Liabilities settled due to dispositions		(250,000)
Accretion expense		226,203
Balance, June 30, 2005	**$**	**6,636,013**

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:

	Number of shares		Amount
Balance, December 31, 2004	47,703,775	$	87,943,635
Exercise of stock options	153,716		248,458
Issue of flow through common shares	2,727,500		12,001,000
Allocated from contributed surplus	-		143,739
Share issue costs, net of future tax effect of $295,022	-		(572,691)
Tax benefit renounced to shareholders	-		(3,402,381)
Balance, June 30, 2005	**50,584,991**	**$**	**96,361,760**

The Company issued subscription receipts late in 2004 for total proceeds of $30,000,007. As at December 31, 2004, the proceeds were being held in trust until closing of the acquisition of natural gas and natural gas liquids properties (Note 2 – Acquisitions). Upon closing of the acquisition on February 1, 2005, the receipts were exchanged for common shares of the Company on a 1 for 1 basis.

On March 31, 2005, the Company issued 2,727,500 flow-through common shares at a price of $4.40 per share for gross proceeds of $12,001,000.

As at June 30, 2005, the Company had an obligation to incur qualifying exploration expenditures of $8,200,000 to satisfy terms of the flow-through common shares issued during the previous year and an obligation to incur qualifying exploration expenditures of $12,001,000 to satisfy terms of the flow-through common shares issued during the period.

(c) Stock options:

The Company has established a stock option plan (the "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 of June 30, 2005 there were 2,689,700 options to purchase shares outstanding.

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

	Number of options outstanding		Weighted average exercise price
Balance, December 31, 2004	**1,895,083**	**$**	**1.59**
Granted	**1,015,000**		**3.40**
Exercised	**(153,716)**		**1.62**
Cancelled	**(66,667)**		**1.85**
Balance, June 30, 2005	**2,689,700**		**2.26**
Exercisable at June 30, 2005	**1,855,667**	**$**	**1.82**

The following table summarizes information about the stock options outstanding and exercisable at June 30, 2005.

	Options outstanding				Options exercisable		
Range of exercise price	Options outstanding		Weighted average exercise price	Weighted average remaining term	Exercisable		Weighted average exercise price
$0.99	**344,250**	**$**	**0.99**	**2.7**	**344,250**	**$**	**0.99**
$1.45 - 1.61	**853,750**		**1.46**	**3.0**	**864,750**		**1.45**
$1.75 - 1.90	**276,700**		**1.86**	**3.8**	**241,667**		**1.88**
$2.66	**200,000**		**2.66**	**4.4**	**66,667**		**2.66**
$3.25 - $3.77	**1,015,000**		**3.40**	**4.7**	**338,333**		**3.40**
Total	**2,689,700**	**$**	**2.26**	**3.8**	**1,855,667**	**$**	**1.82**

(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 six months ended June 30, 2005, Delphi recorded non-cash compensation expense of $982,550 (2004 - $169,706).

During the six month period ended June 30, 2005, the Company granted 1,015,000 options (2004 – 350,000). 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 $1.61 per share (2004 - $0.86). The weighted average assumptions used in the Black-Scholes model to determine fair value are as follows:

	Six Months Ended June 30	
	2005	2004
Risk free interest rate (%)	**4.5**	4.0
Expected life (years)	**5**	5
Expected volatility (%)	**48**	46

(e) Contributed surplus:

The following table outlines the changes in the amount of contributed surplus:

		Amount
Balance, December 31, 2004	**$**	1,072,444
Stock-based compensation expense		982,550
Reclassification to common shares on exercise		(143,739)
Balance, June 30, 2005	**$**	**1,911,255**

(f) Earnings (loss) per share:

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

	Three Months Ended June 30		Six Months Ended June 30	
	2005	2004	**2005**	2004
Basic	**50,540,265**	25,331,634	**49,163,794**	25,297,522
Diluted	**50,863,829**	25,747,763	**49,487,358**	25,713,651

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

Note 8: 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.

(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 physical forward contracts are subject to market risk from fluctuating commodity prices and exchange rates. Gains and losses on the contracts are offset by changes in the value of the Company's production which are presently recognized in earnings in the same period as the production revenue.

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

Time Period	Commodity	Type of Contract	Quantity Contracted	Canadian Price (Per GJ/bbl)
April 2005 – October 2005	Natural Gas	Financial	2,500 GJ/d	$6.31 fixed
April 2005 – October 2005	Natural Gas	Financial	2,000 GJ/d	$6.00 floor/$6.90 ceiling
July 2005 – October 2005	Natural Gas	Physical	1,000 GJ/d	$7.05 fixed
November 2005 – March 2006	Natural Gas	Financial	2,000 GJ/d	$7.79 fixed
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$8.00 floor/$8.90 ceiling
November 2005 – March 2006	Natural Gas	Physical	2,000 GJ/d	$7.50 floor/$9.65 ceiling
July 2005 – September 2005	Crude Oil	Financial	300 bbl/d	$54.66 fixed
October 2005 – December 2005	Crude Oil	Financial	300 bbl/d	$55.01 fixed

As at June 30, 2005, the Company has marked-to-market its financial fixed price contracts resulting in an unrealized loss on risk management activities of $1,444,684 and an obligation of an equivalent amount.

Note 9: COMMITMENT

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. The future minimum commitments are as follows:

2005	$	887,333
2006		2,231,186
2007		2,230,435
2008		2,093,361
2009		2,124,761
2010		2,156,633
2011		1,818,593

CORPORATE INFORMATION

DIRECTORS

David J. Reid
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Tony Angelidis
Senior Vice President Exploration
Delphi Energy Corp.

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Henry R. Lawrie (1)
Former Chief Accountant
Alberta Securities Commission

Robert A. Lehodey, Q.C. (2)
Partner
Bennett Jones LLP

Andrew E. Osis (1)
Independent Businessman

Lamont C. Tolley (1)
Independent Businessman

(1) Member of the Audit Committee
(2) Member of the Corporate Governance and Compensation Committee

OFFICERS

David J. Reid
President and Chief Executive Officer

Tony Angelidis
Senior Vice President Exploration

Michael S. Kaluza
Vice President Engineering

Brian P. Kohlhammer
Vice President Finance and Chief Financial Officer

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Vice President Corporate Development
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TRANSFER AGENT

CIBC Mellon Trust Company

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: DEE