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press release

DEE – TSX

DELPHI ENERGY CORP. ANNOUNCES SECOND QUARTER 2004 RESULTS

CALGARY, ALBERTA – August 19, 2004 - Delphi Energy Corp. is pleased to announce the consolidated financial and operational results for the interim period ended June 30, 2004.

Second Quarter 2004 Financial Highlights

- Cash flow increased 87% to $3.2 million for the second quarter of 2004 ($0.13/share) compared to $1.7 million ($0.08/share) in 2003.
- Cash flow increased 26% over first quarter 2004, 30% on a per share basis.
- Earnings were $0.8 million ($0.03 per share) compared to $0.7 million ($0.03 per share) for the same period in 2003.
- Operating costs of $7.73 for the second quarter of 2004, a 11% decrease over operating costs of $8.64 in the first quarter of 2004 due to on-going optimization programs.
- Submitted application to list shares on the Toronto Stock Exchange (“TSX”). Company began trading on the TSX August 3, 2004.

Second Quarter 2004 Operational Highlights

- Average production increased 97% to 1,716 boe/d, from production in the 869 boe/d in the second quarter of 2003, a result of acquisition and development volume additions.
- Average production volumes increased 26% over the first quarter of 2004.
- Current production levels are approximately 1,850 boe/d.
- Commenced oil production optimization projects in East Central Alberta, increasing oil production volumes 52% over the first quarter of 2004.

Financial Results and Share Information

Financial Highlights [1] ($000s except per boe and per share amounts)	Three Months Ended June 30 **2004**	 2003	Six Months Ended June 30 **2004**	 2003
Gross petroleum and natural gas sales	**5,803**	3,256	**10,784**	5,942
Per boe	**37.16**	41.16	**38.47**	42.78
Cash flow from operations	**3,248**	1,741	**5,819**	3,299
Per boe	**20.80**	22.01	**20.76**	23.76
Per share – Basic	**0.13**	0.08	**0.23**	0.14
Per share – Diluted	**0.13**	0.07	**0.23**	0.14
Earnings (loss)	**838**	734	**1,776**	1,301
Per boe	**5.37**	9.28	**6.33**	9.37
Per share – Basic & Diluted	**0.03**	0.03	**0.07**	0.06
Capital expenditures	**6,979**	8,351	**12,163**	14,954
Debt, net			**16,824**	6,184
Total assets			**59,291**	35,140
Shares outstanding - weighted average (000s)				
Basic	**25,332**	22,930	**25,298**	22,930
Diluted	**25,747**	23,335	**25,714**	23,194

(1) Amounts for 2003 are restated. Refer to Note 3 to the financial statements.

An Active Second Quarter 2004

The second quarter of 2004 saw record financial results for the Company with cash flow of $3.25 million ($0.13 per share), an 86% increase compared to the second quarter of 2003 and a 26% increase over first quarter of 2004. The strong growth is a result of growth in production volumes and continued improvements in operating efficiencies offsetting a 10% decrease in realized commodity prices.

Production volumes for the second quarter of 2004 nearly doubled to average 1,716 barrels of oil equivalent per day compared to 869 barrels of oil equivalent per day during the second quarter of 2003, and increased 26% compared to first quarter of 2004 primarily from oil production volume additions in east central Alberta.

The Company spent approximately $7.0 million on an active capital program during the second quarter of 2004. As planned, the focus of the capital program shifted to east central Alberta spending approximately $5.0 million on workovers, recompletions, facility upgrades and pipelines. Activity in northwest Alberta slowed with the completion of the Fontas winter program in April and completion of facility and pipeline activity in Berland River.

The exploration program continued during the second quarter of 2004, with the spudding of the Valhalla 10-25 well targeting a Devonian Wabamun prospect. The well was recently cased and is waiting on completion and testing of several uphole prospective zones. The previously announced Berland River 10-22 exploration well successfully completed in the Wabamun formation is being tied in and is expected to commence production at rates up of 8 to 10 million cubic feet per day of raw gas (Delphi 8% net) in early September. A twin to the 10-22 well is scheduled to be drilled starting in early fourth quarter to test potential natural gas reserves within the shallow Cretaceous aged sandstone reservoirs where offsetting analog wells are producing up to 15 million cubic feet per day.

Outlook

The active capital program in east central Alberta focusing on recompletion and workovers of existing wells, as well as upgrading existing battery and water handling facilities has continued into the third quarter, expecting to increase Corporate production volumes above the 2,000 barrel of oil equivalent per day level in early September. The east central Alberta program is expected to be completed early in the fourth quarter.

The 10 well development joint venture focusing on re-entry and by-passed pay opportunities in northwest Alberta has commenced, yielding two successful natural gas discoveries to date. Tie-in of these two wells is expected to be completed during the fourth quarter.

The exploration program will continue this fall and winter with the drilling of two wells in the Berland River area, targeting both Devonian Nisku and shallower Cretaceous prospects.

The Company continues to successfully execute on it's growth plan focusing capital spending largely on development projects in both core areas of east central and northwest Alberta, complimented by an active successful high impact exploration program. The current strong oil and gas commodity price environment is providing additional financial performance upside to our ongoing operational growth.

Management's Discussion and Analysis

The following discussion and analysis provided by the management of Delphi Energy Corp. ("Delphi" or the "Company") should be read in conjunction with the unaudited financial statements for the six months ended June 30, 2004 and 2003 and the audited consolidated financial statements and MD&A for the year ended December 31, 2003 in our annual report, all of which have been prepared in accordance with Canadian generally accepted accounting principles. The date of this MD&A is August 18, 2004. Additional information relating to the Company is available on SEDAR at http://www.sedar.com.

NON-GAAP MEASURES

MD&A contains the term "cash flow from operations", which should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Company's performance. Delphi's determination of cash flow from operations may not be comparable to that reported by other companies. The reconciliation between net earnings and cash flow from operations can be found in the consolidated statements of cash flows. The Company also presents cash flow from operations per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Production information and reserves are reported in units of barrels of oil equivalent ("boe"). Disclosure provided in respect of boe units may be misleading particularly if used in isolation. Where amounts are stated on a boe basis, gas volumes have been converted to barrels of oil equivalent at a ratio of 6,000 cubic feet of gas to a barrel of oil equivalent. This conversion ratio is based upon an energy equivalent method primarily applicable at the burner tip and does not represent value equivalence at the wellhead.

FORWARD-LOOKING INFORMATION

The MD&A contains forward-looking or outlook information 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 MD&A.

Production

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2004	2003		**2004**	2003	
Natural gas (mcf/d)	**5,943**	5,049	18	**5,626**	4,440	27
Crude oil (bbl/d)	**684**	5	13,580	**559**	5	11,080
Natural gas liquids (bbl/d)	**42**	23	83	**43**	23	87
Total (boe/d)	**1,716**	869	97	**1,540**	767	101

In the second quarter of 2004 Delphi increased production 97% from the second quarter of 2003, primarily a result of corporate and property acquisitions closed throughout 2003, combined with drilling and tie-in activities during the first half of 2004. The increase in natural gas production for the three months ended June 30, 2004 compared to the same quarter of last year, was a result of drilling and tie-in activities at the Fontas property during winter 2004 and the tie-in of a well in the Berland River area late in the second quarter of 2004. Oil and liquids production for the three months ended June 30, 2004 increased largely due to acquisitions, combined with additions from oil production optimizations in east central Alberta. Production increased 101% for the six months ended June 30, 2004 compared to the same period in 2003 primarily a result of acquisitions closed throughout the second half of 2003. Production for the six months ended June 30, 2004 was comprised of 61% natural gas and 39% crude oil and natural gas liquids, and was spread evenly between the Company's two core regions of northwest Alberta and east central Alberta.

Average production for the quarter of 1,716 boe/d was 26% higher than the first quarter of 2004 largely due to oil optimizations and on-stream efficiencies performed in the Company's east central Alberta area. Natural gas production increased 12% over the production of 5,308 mcf/d in the first quarter of 2004, primarily due to new production of 400 mcf/d added in the second quarter combined with limited disruptions in facilities during the quarter. Oil and liquids production increased 52% in the second quarter of 2004 over the 479 bbl/d reported in the first quarter of 2004 largely due to well reactivations in the east central Alberta region.

The Company will continue its optimization work in the third quarter of 2004 and finish the tie-in of the Berland River 10-22 well drilled in the first quarter of 2004. Delphi's previously announced annual production forecast for 2004 remains unchanged. Total production for the full year of 2004 is on track with previously announced growth targets. Factors influencing the estimated average production for 2004 include drilling success and the time required to bring new or re-completed wells on-stream.

Commodity Pricing

Benchmark Prices

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2004	2003		**2004**	2003	
Natural gas (AECO daily $/GJ)	**6.63**	6.47	2	**6.35**	7.12	(11)
Crude oil (U.S. WTI $/bbl)	**38.32**	28.91	33	**36.73**	31.39	17
Canadian to US dollar exchange rate	**0.7358**	0.6939	6	**0.7472**	0.6712	11

Average Sales Prices

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2004	2003		**2004**	2003	
Natural gas ($/mcf)	**6.41**	6.89	(7)	**6.66**	7.15	(7)
Crude oil ($/bbl)	**35.53**	26.18	36	**36.37**	35.22	3
Natural gas liquids ($/bbl)	**32.77**	37.34	(12)	**33.90**	40.02	(15)
Total ($/boe)	**37.16**	41.16	(10)	**38.47**	42.78	(10)

Both natural gas and crude oil benchmark commodity prices remained strong in the second quarter of 2004, with crude oil prices reaching record highs.

North American natural gas prices increased in the second quarter of 2004. The Company's natural gas prices for both the three and six months ended June 30, 2004 were lower than those realized for the same period in 2003. Natural gas pricing tends to be volatile, a result of periodic imbalances between supply and demand which affects inventory levels. Other factors that affect natural gas pricing include weather conditions, particularly in the Eastern United States, pipeline delivery capacity and the availability of other less expensive sources of energy. Although demand and storage levels have returned to more normal levels, natural gas prices have remained high. Injections have caused inventories to build, however concerns about winter supply are keeping prices strong.

Crude oil prices have remained strong in the second quarter of 2004 with WTI averaging US$38.32/bbl. While US dollar world oil prices were higher in both the second quarter and the first six months of 2004 compared to the same periods of 2003, the Company's realized prices were partially offset by the effect of the stronger Canadian dollar and widening heavy oil differentials. Recent volatility in crude oil prices seem likely to continue. Supply concerns and speculation around those concerns will likely continue to support higher crude prices for the remainder of 2004. Many factors could affect crude oil prices for the remainder of 2004 not the least of which are, uncertainty around the world, OPEC's actual production levels and concerns around the growing terrorist threat in the Middle East.

The Company enters into financial instruments to reduce commodity price volatility, increase cash flow stability and protect acquisition economics.

At June 30, 2004 the Company had the following physical gas sales contracts outstanding:

Year	Time Period	Commodity	Type of Contract	Quantity Contracted	Price
2004	April 2004 – October 2004	Natural Gas	Fixed price	1,000 GJ/d	$5.19 fixed
2004	May 2004 – October 2004	Natural Gas	Fixed price	2,000 GJ/d	$6.33 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$6.88 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$7.70 fixed
2004	May 2004 – June 2004	Crude Oil	Fixed price	250 bbl/d	$48.45 WTI (1)
2004	July 2004 – September 2004	Crude Oil	Fixed price	200 bbl/d	$47.16 WTI(1)
2004	October 2004 – December 2004	Crude Oil	Fixed price	100 bbl/d	$45.75 WTI(1)

(1) Represents WTI prices converted to Canadian$ at the then current exchange rates at the time the hedge was entered into

Revenue

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($000s)	**2004**	2003		**2004**	2003	
Natural gas	**3,468**	3,166	10	**6,815**	5,747	19
Crude oil	**2,211**	10	20,010	**3,701**	30	12,237
Natural gas liquids	**124**	80	55	**268**	165	62
Total	**5,803**	3,256	78	**10,784**	5,942	81

For the three months ended June 30, 2004, revenues increased over the same period in 2003 due to 97% higher production volumes largely offset by the decrease in commodity prices. During the six months ended June 30, 2004 revenues increased 81% compared to the same period in 2003 primarily due to higher production. Quarter-over-quarter total revenues increased 17%, entirely as a result of increased production. Of the increase in total revenue from the first quarter of 2004, 15% is attributable to natural gas, and 85% is attributable to crude oil and natural gas liquids.

Royalties

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
Crown, before royalty rebates	**865**	673	29	**1,578**	1,293	22
Royalty Credits:						
Alberta royalty tax credit	**(22)**	33	167	**(63)**	27	333
Gas Cost Allowance	**(550)**	-	100	**(800)**	-	100
Net crown royalties	**293**	706	(58)	**715**	1,320	(46)
Freehold and gross overriding	**226**	33	588	**376**	47	700
Total royalties	**519**	739	(30)	**1,091**	1,367	(20)
Per boe ($)	**3.34**	9.32	(64)	**3.89**	9.84	(60)
Percent of total revenue	**8.9%**	22.7%	(60)	**10.1%**	23.0%	(56)

Delphi pays royalties to the provincial government, freeholders, which can be individuals or companies, and other oil and gas operators, who own surface or mineral rights. The Company also receives Gas Cost Allowance (“GCA”), for eligible capital expenditures during the year and Alberta Royalty Tax Credit (“ARTC”) tax rebates 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. As prices increase or as there is an increase in higher producing wells royalty rates also increase.

While crown royalties before royalty credits increased 29% in the second quarter of 2004 over 2003, as a percentage of revenue crown royalties decreased from 20.7% to 14.9% primarily a result of lower natural gas pricing in 2004, combined with a higher percentage of revenue from non-crown burdened or royalty free oil wells. Net crown royalty expense decreased 58%, for the second quarter of 2004 compared to 2003, primarily a result of increased GCA rebates for current and prior periods resulting from increased capital spending on gas facilities in northwest Alberta. Freehold and gross overriding royalties increased in the second quarter of 2004 compared to 2003 due to acquisitions of properties with higher encumbrances. Royalties for the six months ended June 30, 2004 are 20% lower than the same period in 2003. This decrease was due to the same reasons explained above for the second quarter of 2004.

Quarter over quarter crown royalties decreased 31% due to higher than anticipated GCA rebates for 2003 combined with an increase in current GCA installments. Freehold and gross overriding royalties increased 52% in the three months ended June 30, 2004 compared to the first three months of 2004 due to higher production from oil properties with higher encumbrances.

Delphi is estimating the royalty rate for Company production to average between 17% and 20% of revenue. Royalty rates can vary according to a number of factors including the difference in reference prices compared to wellhead prices, royalty holiday status of wells, individual well production and proportionate types of royalties.

Operating Expenses

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2004	2003		**2004**	2003	
Total operating costs ($000's)	**1,208**	484	150	**2,280**	768	197
Per boe ($)	**7.73**	6.11	26	**8.13**	5.53	47
Percent of total revenue	**20.2%**	14.2%	42	**21.1%**	12.9%	64

Operating expenses increased $0.7 million for the three months ended June 30, 2004 and $1.5 million for the six months ended June 30, 2004, compared to the same periods in 2003. A primary factor for the increase in costs was the increase in production in the first and second quarters of 2004 over the same periods in 2003. On a per boe basis second quarter operating costs have increased 26% from the same quarter in 2003 and 47% for the six months ended June 30, 2004 compared to the same period in 2003, primarily a result of the acquisition of higher operating cost oil properties in the second half of 2003.

Compared to the first quarter of 2004 operating costs on a boe basis decreased 12% for the three months ended June 30, 2004, due to increased production and on-going reactivations and optimization work in east central Alberta. The Company is anticipating further reductions in operating costs in the third quarter of 2004, both on a cost and a boe basis, as added costs of bringing on recompleted wells and newly commissioned facilities spent in the second quarter will be offset by recognition of full production capabilities.

The Company is continually focusing on reduction of operating costs. Total operating costs, on a per unit basis, are expected to decrease as more production volumes are added and the Company continues to create operating synergies in its core areas of operation.

Transportation

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
	2004	2003		**2004**	2003	
Total transportation costs ($000's)	**262**	153	71	**425**	290	47
Per boe ($)	**1.67**	1.93	(13)	**1.52**	2.08	(27)
Percent of total revenue	**4.5%**	4.7%	(4)	**3.9%**	4.9%	(20)

Transportation costs for the three months ended June 30, 2004 are higher than the costs recorded in the same period of 2003 due to an increase in trucked oil volumes in the second quarter of 2004.

Effective January 1, 2004, and consistent with the adoption of the new Canadian accounting standard for generally accepted accounting principles, transportation costs have been reclassified as an expense in the consolidated statements of earnings and retained earnings for the three months ended June 30, 2004 and 2003. Previously, as was industry practice, transportation costs were netted off revenue. The adoption of this guideline had no impact on the results of operations or financial position of the Company for the three month periods ended June 30, 2004 and 2003.

General and Administrative

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
General and administrative costs	**947**	191	396	**1,570**	325	383
Overhead recoveries	**(165)**	**-**	100	**(232)**	-	100
Salary reallocations	**(132)**	(51)	159	**(289)**	(103)	181
Net	**650**	140	364	**1,049**	222	373
Per boe ($)	**4.16**	1.80	135	**3.75**	1.61	134

The increase in general and administrative costs (“G&A”) for both the second quarter of 2004 and the six months ended June 30, 2004,compared to the same periods in 2003, is primarily due to additional staff and higher office rent required as a result of the increased size of the Company’s operations and its increased asset base. Additional public company expenses increased G&A costs, a result of the private company becoming public in June 2003. In January 2004, the Company adopted the new accounting policy with respect to the Stock Based Compensation regulations. This new policy resulted in a non-cash expense of $192 thousand charged to G&A for the second quarter of 2004. Overhead recoveries recorded in the second quarter of 2004 are primarily due to the acquisition of operated areas throughout 2003.

G&A costs increased 63% in the second quarter of 2004 over the first quarter of 2004 primarily due to one time compensation expenses. Overhead recoveries in the second quarter increased from the first quarter of 2004 largely a result of a larger number of operated capital projects in the second quarter of 2004.

The Company’s G&A forecast for 2004 is estimated to be approximately $2.75 per boe. This estimate includes higher reserve evaluation costs due to the adoption of National Instrument 51-101, “*Standards of Disclosure for Oil and Gas Activities*”, non-cash costs associated with the adoption of the amended Stock Based Compensation regulations and additional listing fees required to move to the TSX from the TSX-V.

Interest

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
Financing	**100**	21	376	**246**	28	779
Other	**-**	(30)	100	**13**	(41)	132
Total Interest	**100**	(9)	1,211	**259**	(13)	28,500
Per boe ($)	**0.64**	(0.13)	592	**0.92**	(0.11)	936

Interest expense was higher in the second quarter of 2004 compared to the same period a year ago, a result of increased average debt balances offset slightly by lower interest rates. Bank debt has increased $11.7 million from June 30, 2003 to June 30, 2004, a result of an accelerated winter exploration and development program in northwest Alberta, combined with an active capital program in east central Alberta during spring/summer 2004.

Interest expense in the second quarter of 2004 decreased 37% from the first quarter. Included in the first quarter was an annual financing fee.

Depletion, Depreciation and Asset Retirement Obligation ("DD&A")[1]

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($000s except per boe amounts)	**2004**	2003		**2004**	2003	
Depletion and depreciation	**1,956**	475	312	**3,491**	1,364	156
Accretion expense	**64**	9	611	**128**	18	611
Total	**2,020**	484	317	**3,619**	1,382	162
Per boe ($)	**12.94**	6.13	111	**12.92**	9.95	30

(1) Amounts for 2003 are restated. Refer to Note 2 to the financial statements.

For both the three and six months ended June 30, 2004 the depletion and depreciation of capital assets and the accretion of the asset retirement obligation increased 317% and 162% respectively, compared to the same periods in 2003. The increase is due to higher production and a larger capital base in 2004.

Effective January 1, 2004 the Company retroactively adopted the recommendations of the Canadian Institute of Chartered Accountants ("CICA") Section 3110, "Asset Retirement Obligations" ("ARO"). The standard requires companies to recognize the liability associated with future abandonment and reclamation costs in the financial statements at the time the liability is incurred. Asset retirement obligations are initially measured at fair value in each period and are subsequently adjusted for the accretion of discount and any changes to the underlying cash flows. The asset retirement cost is capitalized as part of property, plant and equipment and amortized to income consistent with the depletion and depreciation of the underlying asset. Upon adoption of CICA Section 3110 effective January 1, 2004 the Company adjusted its future abandonment and reclamation costs retroactively. The effect of the adoption of the ARO standard has resulted in an increase to net property, plant and equipment of $1.5 million, an increase to goodwill of $1.5 million, an increase to the asset retirement obligation of $2.4 million, a decrease to the future tax liability of $337 thousand and a reduction to the deficit of $863 thousand.

Income Taxes

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
($000s)	**2004**	2003		**2004**	2003	
Current	**8**	9	(11)	**31**	9	244
Future (recovery)	**198**	522	(62)	**254**	616	(59)
Total income taxes	**206**	531	(61)	**285**	625	(54)

The provision for future income taxes was lower in the six months ended June 30, 2004 compared with the same period of 2003 as a result of a one percent tax rate reduction to the Alberta corporate income tax rate and reductions to the Company's federal tax provision. This tax rate reduction resulted in a $327 thousand benefit in the for the first six months of 2004. Current taxes for the six months ended June 30, 2004 are Federal Large Corporations Tax ("LCT"). As at December 31, 2003 the Company had over $37 million in tax pools available for use and will not be cash-taxable in 2004.

Net Income

The Company's net earnings for the second quarter of 2004 were $838 thousand or $0.03 per share on a diluted basis, versus $734 thousand or $0.03 per share for the same period in 2003. Earnings in the second quarter were positively affected by higher volumes, royalty rebates and lower effective tax rates. These increases were offset by weaker commodity prices and higher expenses.

Net earnings for the six months ended June 30, 2004 increased 36% to $1.8 million ($0.07 per share) from $1.3 million ($0.06 per share) during the same period in 2003. The increase was primarily due to higher revenues from increased production and higher royalty rebates received in 2004.

Netback Analysis

	Three Months Ended June 30		Change (%)	Six Months Ended June 30		Change (%)
Barrels of oil equivalent ($/boe)	**2004**	2003		**2004**	2003	
Sales price after hedging	**37.16**	41.16	(10)	**38.47**	42.78	(10)
Royalties	**3.34**	9.32	(64)	**3.89**	9.84	(60)
Operating expenses	**7.73**	6.11	27	**8.13**	5.53	47
Transportation	**1.67**	1.93	(13)	**1.52**	2.08	(27)
Operating netback	**24.42**	23.80	3	**24.93**	25.33	(2)
G&A	**2.93**	1.80	63	**3.14**	1.61	95
Interest	**0.64**	(0.13)	592	**0.92**	(0.11)	936
Current income taxes	**0.05**	0.12	(58)	**0.11**	0.07	57
Cash netback	**20.80**	22.01	(5)	**20.76**	23.76	(13)
Stock based compensation	**1.23**	-	100	**0.61**	-	100
Depletion, depreciation and accretion	**12.94**	6.13	111	**12.92**	9.95	30
Future income taxes	**1.26**	6.60	(81)	**0.90**	4.44	(80)
Net Income	**5.37**	9.28	(42)	**6.33**	9.37	(32)

Liquidity and Capital Resources

Capitalization and Debt

As at ($000s except share amounts)	**June 2004**
Common shares outstanding	**25,348**
Share price (end of period) ($)	**1.85**
Market value of common shares	**46,894**
Debt including working capital deficit	**16,824**
Total capitalization	**63,718**
Debt as a % of capitalization	**26%**

Liquidity

At June 30, 2004 the Company had $15.4 million outstanding on its credit facility and a working capital deficit of $1.4 million, totaling $16.8 million of total net debt. As at June 30, 2004 the Company had accounts receivable of $3.5 million consisting of $2.1 million of revenue receivable, $0.7 million of joint venture receivables and $0.7 million of royalty and tax rebates. Included in the Company's $5.9 million of accounts payable is $0.8 million of operating payables, $0.6 million of royalty payables, $3.5 million of capital payables and $1.0 million of joint venture payables. The Company has a $23 million operating credit facility consisting of a $18 million demand revolving operating facility and a $5 million acquisition and development credit facility.

Operating Activities

Cash flow from operating activities was $3.2 million or $0.13 per share in the second quarter of 2004, compared to $1.7 million or $0.07 per share for the same period a year ago. The increase in cash from operating activities in the second quarter of 2004 is primarily due to increased production volumes and lower royalties offset by decreased commodity pricing.

Cash flow from operations increased 76% to $5.8 million for the six months ended June 30, 2004 compared to $3.0 million in the same period in 2003 due to same reasons explained above for the second quarter of 2004. On a per boe basis cash flow from operations for the six months ended June 30, 2004 was $0.23 per share compared to $0.14 per share for the same period in 2003.

Cash flow increased 26% in the second quarter of 2004 from the first quarter primarily as a result of increased production.

Financing Activities

During the second quarter of 2004 cash generated from financing activities amounted to $2.8 million, comprised of an increase to bank debt of $2.75 million and proceeds on the exercise of options totaling $17 thousand. Cash generated from financing activities in the second quarter of 2003 totaled $4.7 million of which $2.0 million was from increased bank debt and $2.7 million was from the issue of shares.

Investing Activities

Cash used in investing activities amounted to $7.4 million in the second quarter of 2004 compared with $8.8 million in the second quarter of 2003. Cash invested in the second quarter of 2004 was comprised of $7.0 million of capital expenditures, with the remainder due to changes in non-cash working capital.

Drilling Results

During the second quarter of 2004 the Company did not drill any new wells. The Company's focus during the second quarter was on recompleting and reactivating zones in existing wells and facility optimizations.

	Three Months Ended June 30, 2004		**Six Months Ended June 30, 2004**	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	**-**	**-**	**8.0**	**1.4**
Oil wells	**-**	**-**	**-**	**-**
Dry holes	**-**	**-**	**3.0**	**0.6**
Total wells	**-**	**-**	**11.0**	**2.0**
Success rate (%)	**-**	**-**	**73%**	**70%**

Capital Invested

($000s)	Three Months Ended June 30 2004	2003	Change (%)	Six Months Ended June 30 2004	2003	Change (%)
Land	**130**	157	17	**486**	370	31
Seismic	**94**	421	78	**98**	424	(77)
Drilling and completions	**3,291**	439	650	**4,846**	1,646	194
Equipping and facilities	**2,690**	412	553	**5,723**	2,524	127
Property acquisitions	**633**	6,922	(91)	**633**	10,020	(94)
Capitalized expenses	**161**	-	100	**315**	-	100
Other	**(5)**	-	100	**29**	(30)	197
Total cash capital invested	**6,994**	8,351	(16)	**12,130**	14,954	(19)
Asset retirement obligation	**(15)**	-	100	**33**	-	100
Total capital invested	**6,979**	8,351	(16)	**12,163**	14,954	(19)

During the second quarter of 2004 the majority of Delphi's capital expenditures were directed towards oil production optimizations and reactivations in the east central region of Alberta. Seventy four percent of the Company's second quarter capital expenditures were directed towards its core region of east central Alberta, where the Company spent $5.2 million. In John Lake $1.0 million was spent on reactivations and acquiring our partners working interests. The Company spent a further $1.7 million in the Sounding Lake area on recompletions and facility upgrades to maintain and expand production capacity. In northwest Alberta work began on the tie-in of the exploratory well drilled in the Berland River area in the first quarter and the fourth of the exploratory joint venture wells began drilling in the Valhalla area.

Outstanding Share Data

The common shares of Delphi began trading on the Toronto Stock Exchange August 3, 2004, under the symbol DEE. The following table summarizes the common shares issued during 2004 and 2003.

(000's)	Number of Shares/Warrants
Class A common shares:	
Balance, December 31, 2002	18,232
Issued for cash pursuant to a private placement	1,836
Issued to DT shareholders with respect to the reverse take-over of Rise	**20,068**
Common shares of Rise at date of acquisition	2,862
Issue of common shares with respect to the acquisition of Murias	358
Issue of common shares with respect to the acquisition of Fish Creek	540
Issue of common shares with respect to asset acquisitions	154
Issue of flow-through common shares for cash	1,136
Exercise of stock options for cash	100
Balance, December 31, 2003	**25,218**
Exercise of stock options for cash	130
Balance, June 30, 2004	**25,348**

(000's except per share price amount)	**Six Months Ended June 30, 2004**	Year Ended December 31, 2003
Share price ($)		
High	**$2.15**	$1.90
Low	**$1.66**	$1.32
Close at end of period	**$1.85**	$1.75
Weighted average number of common shares outstanding		
Basic	**25,298**	21,711
Diluted	**25,714**	21,897
Number of common shares outstanding	**25,424** (1)	25,218
Number of stock options outstanding	**1,817** (1)	1,852

(1) As at August 18, 2004

Selected Quarterly Information

	2004		2003				2002	
	Q2	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3
Production								
Oil and NGLs (bbl/d)	**726**	**479**	520	282	28	27	43	42
Natural gas (mcf/d)	**5,943**	**5,308**	5,648	5,779	5,049	3,824	1,131	601
Barrels of oil equivalent (boe/d)	**1,716**	**1,364**	1,461	1,245	869	664	232	142
Financial								
($000s, except as noted)								
Petroleum and natural gas revenue	**5,803**	**4,981**	4,500	3,893	3,256	2,686	700	368
Cash flow from operations	**3,248**	**2,572**	1,924	1,441	1,741	1,560	443	207
Per share basic ($)	**0.13**	**0.10**	0.08	0.06	0.08	0.06	0.04	0.02
Per share diluted ($)	**0.13**	**0.10**	0.08	0.06	0.07	0.06	0.04	0.02
Net earnings (loss)	**838**	**939**	217	(283)	734	568	87	(78)
Per share basic & diluted ($)	**0.03**	**0.04**	0.01	(0.01)	0.03	0.03	0.01	(0.01)
Per unit information								
Natural gas ($/mcf)	**6.41**	**6.93**	6.10	6.12	6.89	7.50	5.77	3.41
Oil ($/bbl)	**35.53**	**37.70**	27.04	27.45	26.18	43.65	-	-
Natural gas liquids ($/bbl)	**32.77**	**34.94**	37.11	6.59	37.34	42.90	25.05	46.35
Oil equivalent ($/boe)	**37.16**	**40.12**	33.48	33.99	41.16	44.92	32.84	28.13
Operating netback ($/boe)	**24.43**	**25.57**	18.00	16.35	23.78	27.37	20.06	24.56

DELPHI ENERGY CORP.
Balance Sheets

($000s)		June 30 **2004**		December 31 2003
Assets		(unaudited)		(audited)
				(restated Note 2)
Current assets:				
Accounts receivable	**$**	**3,501**	$	4,611
Prepaid expenses and deposits		**921**		659
		4,222		5,270
Property, plant and equipment (Note 2,3,4)		**52,634**		43,963
Goodwill (Note 3)		**2,235**		2,235
	$	**59,291**	$	51,468
Liabilities and Shareholders' Equity				
Current liabilities:				
Accounts payable and accrued liabilities		**5,861**		6,951
Bank indebtedness (Note 5)		**15,385**		9,006
		21,246		15,957
Future income taxes (Note 3,7)		**3,924**		3,670
Asset retirement obligations (Note 2,3)		**3,349**		3,189
Shareholders' equity:				
Share capital (Note 6)		**30,065**		29,802
Contributed surplus (Note 2,6)		**749**		-
Deficit (Note 3)		**(42)**		(1,150)
		30,772		28,652
	$	**59,291**	$	51,468

DELPHI ENERGY CORP.

Statements of Earnings and Deficit (unaudited)

($000s)	Three months ended June 30		Six months ended June 30	
	2004	2003	**2004**	2003
		(restated Note 2)		(restated Note 2)
Revenue:				
Petroleum and natural gas	**$5,803**	$3,256	**$10,784**	$5,942
Royalties (net of Alberta Royalty Tax Credit)	**(519)**	(739)	**(1,091)**	(1,367)
	5,284	2,517	**9,693**	4,575
Expenses:				
Operating	**1,208**	484	**2,280**	768
Transportation (Note 2)	**262**	153	**425**	290
General and administrative	**650**	140	**1,049**	222
Interest (income)	**100**	(9)	**259**	(13)
Depletion, depreciation and accretion	**2,020**	484	**3,619**	1,382
	4,240	1,252	**7,632**	2,649
Earnings before taxes	**1,044**	1,265	**2,061**	1,926
Taxes:				
Current taxes	**8**	9	**31**	9
Future income taxes (Note 3,7)	**198**	522	**254**	616
	206	531	**285**	625
Net earnings (Note 3)	**838**	734	**1,776**	1,301
Deficit, beginning of period	**(880)**	(2,723)	**(1,150)**	(3,290)
Stock based compensation – retroactive adoption (Note 2)	**-**	-	**(668)**	-
Deficit, end of period	**$(42)**	$(1,989)	**$(42)**	$(1,989)
Earnings per share:				
Basic and diluted	**$0.03**	$0.03	**$0.07**	$0.06
Weighted average number of common shares outstanding ($000s)				
Basic	**25,332**	22,930	**25,298**	22,930
Diluted	**25,747**	23,335	**25,714**	23,194

DELPHI ENERGY CORP.

Statements of Cash Flows (unaudited)

($000s)	Three months ended June 30		Six months ended June 30	
	2004	2003	**2004**	2003
Cash provided by (used in):		(restated Note 2)		(restated Note 2)
Operations:				
Net earnings	**$838**	$734	**$1,776**	$1,301
Add non-cash items:				
Depletion, depreciation and accretion	**2,020**	485	**3,619**	1,382
Stock based compensation expense	**192**	-	**170**	-
Future income taxes	**198**	522	**254**	616
Funds from operations	**3,248**	1,741	**5,819**	3,299
Change in non-cash working capital (Note 8)	**1,368**	2,334	**(2,272)**	2,170
	4,616	4,075	**3,547**	5,469
Financing:				
Issue of shares, net of share issue costs	**17**	2,682	**174**	4,400
Increase in bank indebtedness	**2,748**	2,054	**6,379**	3,644
	2,765	4,736	**6,553**	8,044
Investing:				
Property, plant and equipment additions	**(6,994)**	(8,351)	**(12,130)**	(14,954)
Change in non-cash working capital (Note 8)	**(387)**	(460)	**2,030**	(154)
	(7,381)	(8,811)	**(10,100)**	(15,108)
Decrease in cash	**-**	-	**-**	(1,595)
Cash, beginning of period	**-**	-	**-**	1,595
Cash, end of period	**$-**	$-	**$-**	$-

DELPHI ENERGY CORP.
Notes to Financial Statements
(Unaudited)

Note 1: ACCOUNTING POLICIES

The interim financial statements of Delphi Energy Corp. ("Delphi" or the "Company") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2003, except as noted below. Certain prior years' amounts have been reclassified to conform with current presentation. The interim financial statements should be read in conjunction with the consolidated financial statements and the notes thereto in the Company's annual report for the year ended December 31, 2003.

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 2: CHANGE IN ACCOUNTING POLICIES

(a) Stock based compensation:

Effective January 1, 2004 the Company adopted the Canadian Institute of Chartered Accountants ("CICA") section 3870, "Stock based Compensation and Other Stock based Payments", retroactively without restatement of prior periods. The Company is required to record a compensation expense for all options granted over the vesting period based on the option's fair value. The compensation expense is included in the Company's general and administrative expenses. This change resulted in a decrease to the deficit of $668,286 and an increase to contributed surplus of the same amount.

(b) Asset Retirement Obligation

Effective January 1, 2004 the Company retroactively adopted the recommendations of CICA Section 3110, "Asset Retirement Obligations" ("ARO"). The standard requires companies to recognize the liability associated with future abandonment and reclamation costs in the financial statements at the time when the liability is incurred. Asset retirement obligations are initially measured at fair value and subsequently adjusted for the accretion of discount and any changes to the estimated underlying cash flows. The asset retirement cost is capitalized as part of property, plant and equipment and amortized to income consistent with the depletion and depreciation of the underlying asset. Note 3 discloses the effect of the adoption of this Section.

(c) Property, Plant and Equipment – Oil and Gas

Effective January 1, 2004 the Company adopted Accounting Guideline 16, "Oil and Gas Accounting – Full Cost" ("AcG-16"), which replaces Accounting Guideline 5, "Full Cost Accounting in the Oil and Gas Industry". AcG-16 modifies how the ceiling test is performed and is consistent with CICA Section 3063, "Impairment of Long-lived Assets". The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its estimated undiscounted future cash flows. The impairment amount is the difference between the carrying amount and the estimated fair value of the asset. This approach incorporates risks and uncertainties in the expected future cash flows, which are discounted using a risk free rate. The adoption of AcG-16 had no effect on the Company's financial results.

(d) Transportation

Effective January 1, 2004, and consistent with the adoption of the new Canadian accounting standard for generally accepted accounting principles, transportation costs are presented as an expense in the Statement of Earnings and Deficit. The new standard defines the sources of GAAP and effectively eliminates industry practices as a source of GAAP. In 2003, as was industry practice, transportation costs were deducted from revenue and have been reclassified to conform to the presentation adopted in 2004.

Note 3: ASSET RETIREMENT OBLIGATIONS

The Company retroactively adopted the new recommendations on the recognition of the obligations to retire long-lived tangible assets. This change was effective January 1, 2004, with the revisions being applied retroactively. The effects were as follows:

Balance Sheet - As at December 31, 2003	As Reported	Change	As Restated
($000s)			
Assets			
Petroleum and natural gas properties	53,106	1,668	54,774
Accumulated depletion and depreciation	(10,638)	(173)	(10,811)
Net book value	42,468	1,495	43,963
Goodwill	784	1,451	2,235
Liabilities and shareholders' equity			
Asset retirement obligations	-	3,189	3,189
Future abandonment and restoration costs	768	(768)	-
Future income taxes	4,007	(337)	3,670
Deficit	(2,013)	863	(1,150)

Statement of Earnings Three months ended June 30, 2003	As Reported	Change	As Restated
($000s)			
Depletion, depreciation and accretion	461	23	484
Net earnings	757	(23)	734

Statement of Earnings Six months ended June 30, 2003	As Reported	Change	As Restated
($000s)			
Depletion, depreciation and accretion	1,340	42	1,382
Net earnings	1,343	(42)	1,301

At June 30, 2004 the estimated total undiscounted amount required to settle the asset retirement obligations ("ARO") was $4.8 million. These obligations are to be recognized based on the economic lives of the underlying assets, which currently extend 16 years into the future. This amount has been discounted using a credit adjusted risk free interest rate of 8%.

Changes to Asset Retirement Obligation	**Six Months Ended June 30, 2004**
($000s)	
Asset retirement obligation at beginning of period	**3,189**
Liabilities incurred during the period	**32**
Liabilities settled during period	**-**
Accretion expense	**128**
Asset retirement obligation at June 30, 2004	**3,349**

Note 4: PROPERTY, PLANT AND EQUIPMENT

June 30, 2004	Cost	Accumulated Depletion and Depreciation	Net book Value
($000s)			
Petroleum and natural gas properties	**52,753**	**12,727**	**40,026**
Production equipment	**12,115**	**1,112**	**11,003**
Asset retirement cost	**1,701**	**289**	**1,412**
Furniture, fixtures and office equipment	**368**	**175**	**193**
	66,937	**14,303**	**52,634**

December 31, 2003			
($000s)			
Petroleum and natural gas properties	42,922	9,925	32,997
Production equipment	9,871	572	9,299
Asset retirement cost	1,668	173	1,495
Furniture, fixtures and office equipment	313	141	172
	54,774	10,811	43,963

As at June 30, 2004, unproved properties with capitalized costs of $6.3 million were not subject to depletion.

During the six months ended June 30, 2004, the Company capitalized $0.3 million (2003 - $nil), of general and administrative costs directly related to exploration and development activities.

Adoption of the new guideline for oil and gas accounting using the full cost method, as outlined in note 2, had no effect on the Company's financial statements. The future commodity prices used in the ceiling test prepared on initial adoption were based on January 1, 2004 commodity price forecasts of the Company's independent reserve engineers. These prices have been adjusted for commodity price differentials specific to the Company. The following table summarizes the future benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of future net revenues from the Company's proved reserves exceeded the carrying value of property, plant and equipment and other assets at June 30, 2004.

	WTI ($US/bbl)	Currency exchange rate $US/$Cdn.	Edmonton reference price ($Cdn/bbl)	AECO-C spot price ($Cdn/mmbtu)
2004	$37.25	$0.75	$49.00	$7.15
2005	32.00	0.75	41.75	6.20
2006	32.00	0.75	37.75	5.65
2007	27.00	0.75	35.25	5.35
2008	26.00	0.75	33.75	5.20
Escalate thereafter at:	1.5%/yr		1.5%/yr	1.5%/yr

Note 5: BANK INDEBTEDNESS

At June 30, 2004 the Company had drawn $15.4 on its banking facility. The Company has a financing commitment with a Canadian chartered bank for a revolving operating demand loan and a non-revolving development demand loan. As at June 30, 2004 the Company had a $23 million operating credit facility consisting of an $18 million demand revolving operating facility and a $5 million acquisition and development credit facility. The loans bear interest at bank prime rate plus 0.25% payable monthly and are secured by a $85.0 million demand floating charge debenture and a general security agreement. The borrowing base is subject to a semi-annual and annual review by the lender.

Note 6: SHARE CAPITAL

(a) Authorized:

An unlimited number of voting common shares.

An unlimited number of preferred shares issuable in series.

(b) Issued:

Common shares/warrants:

	Number of Shares/warrants	Amount
Class A common shares:	(000s)	($000s)
Balance, December 31, 2003	25,218	29,753
Stock based compensation – adoption	-	74
Exercised – options	130	188
Balance, June 30, 2004	**25,348**	**30,015**
Warrants:		
Outstanding as at December 31, 2003 and June 30, 2004	**146**	**50**
Balance, June 30, 2004		**30,065**

(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 and employees. The Plan provides for the granting of up 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 equally over a three-year period starting on the date of the grant. The exercise price of each option equals the market price of the Company's common shares on the date of the grant. As of June 30, 2004 there were 2,532,600 common shares reserved for issuance to eligible participants of the Plan.

On June 30, 2004, options for 1,853,417 common shares were outstanding with an exercise price between $0.99 and $1.90, and a weighted average remaining contractual life of 3.78 years.

The following table sets forth a reconciliation of the Plan activity to June 30, 2004.

	Number of options (000s)	Weighted average exercise price
Balance, December 31, 2003	1,852	$1.38
Granted	350	$1.86
Cancelled	(219)	$1.45
Exercised	(130)	$1.45
Balance, June 30, 2004	**1,853**	**$1.46**

(d) Stock Based Compensation

The Company has calculated its stock based compensation expense using the Black-Scholes option pricing model to estimate the fair value of each option granted on the date of grant with weighted average assumptions and resulting values for grants as follows:

	Six Months Ended June 30, 2004
Assumptions	
Risk-free interest rate (%)	**4.00**
Volatility (%)	**46**
Expected life (years)	**5.00**

Results	
Weighted average fair value of options granted	**0.86**

As described in Note 1, the Company adopted the fair value based method of accounting for stock based compensation for its stock option plan retroactively without restating prior periods. Retained earnings at January 1, 2004, was decreased by $668,286 with an increase to contributed surplus of the same amount. Beginning January 1, 2004, stock based compensation is being recognized in earnings and included in general and administrative expenses.

(e) Contributed Surplus

Six Months Ended June 30	**2004**
($000s)	
Contributed surplus at beginning of period	**-**
Stock based compensation adoption	**668**
Stock based compensation expense	**319**
Options exercised	**(89)**
Options cancelled	**(149)**
Contributed surplus at June 30, 2004	**749**

(f) Flow-Through Share Expenditures

Pursuant to the December 18, 2003 flow-through share offering, the Company renounced $2.5 million of qualifying expenditures effective December 31, 2003. Of the total qualifying expenditures renounced, approximately $0.2 million remains to be expended before December 18, 2004.

Note 7: INCOME TAXES

The provision for income taxes for the six months ended June 30, 2004 includes a $254 thousand non-recurring benefit for a one percent reduction in the Alberta corporate income tax rate.

Note 8: CASH FLOWS – CHANGE IN NON-CASH WORKING CAPITAL

	Three Months Ended	Six Months Ended	Three Months Ended	Six Months Ended
	June 30, 2004		June 30, 2003	
($000s)				
(a) Change in non-cash working capital was as follows				
Decrease (increase) in non-cash working capital				
Accounts receivable	**(256)**	**(1,110)**	(1,160)	(1,512)
Prepaid expenses	**115**	**262**	37	(38)
Accounts payable	**(840)**	**1,090**	2,997	3,566
Change in non-cash working capital	**981**	**(242)**	1,874	2,016
Relating to:				
Investing activities	**(387)**	**2,030**	(460)	(154)
Operating activities	**1,368**	**(2,272)**	2,334	2,170
Total non-cash working capital	**981**	**(242)**	1,874	2,016
(b) Other cash flow information:				
Taxes paid	**76**	**82**	33	33
Interest paid	**178**	**323**	26	28

Note 9: FINANCIAL INSTRUMENTS

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 through a combination of fixed price sale contracts with customers and commodity swap agreements with financial counterparties. The forward and futures 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 and recognized in income in the same period and category as the hedged item.

At June 30, 2004 the Company had the following physical sales contracts outstanding:

Year	Time Period	Commodity	Type of Contract	Quantity Contracted	Price
2004	April 2004 – October 2004	Natural Gas	Fixed price	1,000 GJ/d	$5.19 fixed
2004	May 2004 – October 2004	Natural Gas	Fixed price	2,000 GJ/d	$6.33 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$6.88 fixed
2004	Nov 2004 – March 2005	Natural Gas	Fixed price	1,000 GJ/d	$7.70 fixed
2004	May 2004 – June 2004	Crude Oil	Fixed price	250 bbl/d	$48.45 WTI(1)
2004	July 2004 – September 2004	Crude Oil	Fixed price	200 bbl/d	$47.16 WTI(1)
2004	October 2004 – December 2004	Crude Oil	Fixed price	100 bbl/d	$45.75 WTI(1)

(1) Represents WTI prices converted to Canadian$ at the then current exchange rates at the time the hedge was entered into

For further information, please visit our website at www.delphienergy.ca or contact:

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Reader's Advisory:

All numbers stated in barrel of oil equivalent have been converted on the basis of 6 mcf equals 1 boe, unless otherwise stated. Within the MD&A references are made to terms commonly used in the oil and gas industry. Cash flow and cash flow per share are not defined by Generally Accepted Accounting Principles ("GAAP") in Canada and are referred to as non- GAAP measures. Cash flow represents funds from operations as detailed on the consolidated statement of cash flows. Cash flow per share is calculated based on the diluted weighted average number of common shares outstanding as calculated using the treasury method.

The corporate information contained in these pages contains forward-looking forecast information. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Delphi at the time of preparation, may prove to be incorrect. The actual results achieved during the forecast period will vary from the information provided herein and the variations may be material. Consequently, there is no representation by Delphi that actual results achieved will be the same in whole or in part as those forecast.