PEMBINA

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PEMBINA PIPELINE CORPORATION

ANNUAL RESULTS

Pembina Pipeline Corporation 2011 fourth quarter and annual results

Strong performance; pending Provident Energy Ltd. acquisition propels future growth and shareholder value

All financial figures are in Canadian dollars unless noted otherwise. This report contains forward-looking statements and information that are based on Pembina Pipeline Corporation's current expectations, estimates, projections and assumptions in light of its experience and its perception of historical trends. Actual results may differ materially from those expressed or implied by these forward-looking statements. Please see page 36 for more information. This report also refers to financial measures that are not defined by Canadian Generally Accepted Accounting Principles, which have been revised effective January 1, 2010 to converge with International Financial Reporting Standards. For more information about the measures which are not part of Canadian Generally Accepted Accounting Principles ("Non-GAAP Measures") please see page 33.

Pembina Pipeline Corporation ("Pembina" or the "Company") achieved strong fourth quarter and annual 2011 results which were driven by consistent performance in each of the Company's four business units.

On January 16, 2012, subsequent to the Company's 2011 year-end, Pembina announced having entered into an agreement with Provident Energy Ltd. ("Provident") for Pembina to acquire all of the issued and outstanding common shares of Provident by way of a plan of arrangement under the Business Corporations Act (Alberta). This transaction will create a vertically integrated company that provides a more complete line of complementary services to its customers, and is a leading player in the North American energy infrastructure sector with an estimated enterprise value of approximately $10 billion. Pending shareholder and regulatory approval of the acquisition, Pembina expects to increase its monthly dividend from $0.13 per share per month ($1.56 annualized) to $0.135 per share per month ($1.62 annualized), representing a 3.8 percent increase and reflecting management's confidence in the significant operational and financial strength of the combined entity going forward (see "Forward-Looking Statements and Information").

Fourth Quarter Financial Highlights

- Earnings were $45.1 million ($0.27 per share) during the fourth quarter of 2011 compared to $55.2 million ($0.34 per share) for the same period in 2010.
- Adjusted earnings were $43.8 million ($0.26 per share) during the fourth quarter of 2011 compared to $44.8 million ($0.27 per share) in the fourth quarter of 2010 (adjusted earnings is a Non-GAAP measure, see "Non-GAAP Measures" on page 33).
- Cash flow from operating activities was $74.3 million ($0.44 per share) during the fourth quarter of 2011 compared to $54.6 million ($0.33 per share) during the fourth quarter of 2010.
- Adjusted cash flow from operating activities was $66.8 million ($0.40 per share) for the fourth quarter of 2011 compared to $64.9 million ($0.39 per share) for the same period in 2010 (adjusted cash flow from operating activities is a Non-GAAP measure, see "Non-GAAP Measures" on page 33).
- Earnings before interest, taxes, depreciation and amortization ("EBITDA") was $87.0 million ($0.52 per share) in the fourth quarter of 2011 compared to $79.1 million ($0.48 per share) in the fourth quarter of 2010 (EBITDA is a Non-GAAP measure, see "Non-GAAP Measures" on page 33).
- Dividends paid were $65.4 million during the fourth quarter of 2011, representing $0.39 per share ($0.13 per share monthly), compared to $64.6 million in the fourth quarter of 2010 (no change in per share dividend payments).

Year-End Financial Highlights

- Earnings totaled $165.7 million ($0.99 per share) for 2011 compared to $175.8 million ($1.08 per share) in 2010.
- Adjusted earnings increased 20 percent to $208.9 million ($1.25 per share) in 2011 from $173.5 million ($1.06 per share) in 2010.
- Cash flow from operating activities increased 11.6 percent to $287.1 million ($1.72 per share) during 2011 compared to $257.2 million ($1.58 per share) in 2010.
- Adjusted cash flow from operating activities increased 17.8 percent to $297.5 million ($1.78 per share) during 2011 compared to $252.7 million ($1.54 per share) during 2010.
- EBITDA was $364.3 million ($2.18 per share) during 2011 compared to $310.8 million ($1.90 per share) during 2010.

Revenue, net of product purchases, during the fourth quarter of 2011 was $159.8 million compared to $128.5 million during the fourth quarter of 2010. Revenue, net of product purchases, for the full year of 2011 was $604.6 million compared to $497 million during 2010.

Operating margin totaled $104.7 million during the fourth quarter of 2011 compared to $86.2 million during the fourth quarter of 2010 (operating margin is a Non-GAAP measure, see "Non-GAAP Measures" on page 33). Operating margin was $412.7 million for 2011 compared to $341.2 million during 2010.

Strong results from the Company's Midstream & Marketing business played a role in Pembina's fourth quarter and annual 2011 financial results, contributing $23.7 million during the fourth quarter and $93.3 million during the full year to operating margin compared to $12.4 million during the fourth quarter of 2010 and $50.8 million during the full year of 2010. This increase was primarily due to higher volumes and activity on Pembina's Peace Pipeline and Drayton Valley Pipeline systems, stronger commodity prices for the majority of liquid hydrocarbon products, and wider margins.

The Company's Oil Sands & Heavy Oil business also generated strong operating margin of $27.2 million in the fourth quarter and $90.8 million during the full year of 2011 compared to $19.9 million in the fourth quarter and $78.2 million during the full year of 2010, respectively. This increase was largely due to contribution from the new Nipisi and Mitsue Pipelines, which began generating returns in the third quarter of 2011.

The Company's Conventional Pipelines business realized operating margin for the fourth quarter of 2011 of $40.3 million and $177.1 million for the year ended December 31, 2011. This compares to $42.5 million and $169.1 million, respectively, during the same periods of 2010. Higher operating expenses during the quarter, which impacted operating margin, were primarily due to increased integrity work completed in anticipation of higher forecasted future volumes. Higher power costs associated with increased throughput during the fourth quarter also negatively impacted operating margin during the period. Realized gains or losses on power derivatives recorded in this business unit, which provide a hedge for the majority of the power supply, are recognized under finance income. Improved annual results in this business were primarily due to higher volumes on the majority of Pembina's largest systems. During the fourth quarter of 2011, Conventional Pipelines' throughput averaged 422,800 barrels per day ("bpd"), approximately 12.7 percent higher than the same period in 2010 when average throughput was 375,000 bpd. Full year 2011 throughput averaged 413,900 bpd, approximately 11 percent higher than the 374,000 bpd average volume during 2010. Throughput during the fourth quarter and full year 2011 was substantially higher than the same periods in the previous year due to increased industry activity on all of Pembina's major pipeline systems, as well as incremental volumes of approximately 15,000 bpd due to an operational outage on a third party crude oil pipeline from May to September of 2011.

In addition, operating margin was positively impacted by the Company's Gas Services business due to an increase in volumes at Pembina's Cutbank Complex. Average processing volume, net to Pembina, was 263.9 million cubic feet per day ("MMcf/d") during the fourth quarter of 2011, approximately 16 percent higher than the 227.8 MMcf/d processed during the fourth quarter of 2010. Average processing volume for the full year 2011 was 244.5 MMcf/d, representing an 11 percent increase over full year 2010 average processing volume of 220.5 MMcf/d. As a result, this business unit contributed $13.0 million during the fourth quarter and $49.1 million during the full year to operating margin compared, to $11.4 million during the fourth quarter of 2010 and $43.1 million during the full year 2010.

Growth Strategy Highlights

- Capital spending during 2011 totaled $526 million, the majority of which was directed towards the Nipisi heavy oil and Mitsue diluent pipeline projects, a $57 million acquisition of a midstream terminal facility, various expansions on Pembina's conventional pipelines, purchase of the linefill for the Peace Pipeline, and expenditures related to the Musreau Deep Cut Facility and the shallow cut expansion at the Cutbank Complex.
- In June and July of 2011, Pembina completed its Nipisi and Mitsue Pipelines to service the Pelican and Peace River heavy oil regions of Alberta. The Company's Oil Sands & Heavy Oil team is assessing the feasibility of expanding these pipelines and is in active conversations with existing and potential customers regarding various expansion scenarios to accommodate growing production from these regions.
- Throughout 2011, Pembina's Gas Services team progressed two projects at its existing Cutbank Complex and began development of two new projects, the Resthaven and Saturn gas plants, to expand its footprint in areas of high industry activity in the Western Canadian Sedimentary Basin ("WCSB"). These plants are expected to bring Pembina's net enhanced natural gas liquids ("NGL") extraction capacity to approximately 600 MMcf/d, which would be processed largely on a contracted, fee-for-service basis and result in approximately 45,000 bpd of incremental NGL to be transported for additional toll revenue on Pembina's conventional pipelines by the end of 2013, subject to regulatory approval. Pembina expects these expansions could contribute $75 million to $90 million of EBITDA annually, once fully operational (see "Forward-Looking Statements and Information").
- Pembina's Conventional Pipelines invested approximately $71.3 million during 2011, about 40 percent of which was spent to increase the capacity of its Drayton Valley system and to reactivate an existing lateral off of the Peace Pipeline system into the Edson area. This investment will allow Pembina to offer much-needed capacity for producers in these areas of the WCSB.
- The Company's Midstream & Marketing business unit began 2011 with a $57 million acquisition of land and storage assets in the Edmonton area. Acquiring these strategically located terminalling and storage facilities (called the Pembina Nexus Terminal) forms an important piece of Pembina's growth strategy by increasing its ability to provide new, customer-focused services while expanding its overall capabilities. Pembina is developing plans to further increase the interconnectivity of the terminal to enhance its offering to both upstream and downstream customers.
- Pembina's Board of Directors approved a $550 million capital spending plan for 2012, the largest in the Company's history. Pembina expects to target the majority of planned expenditures to its Gas Services and Conventional Pipelines businesses, including the previously announced expansion to its Northern NGL system as well as the Resthaven and Saturn gas plants.

"At Pembina, we believe in going the distance for our stakeholders by delivering on our promises – including generating value through accretive growth and providing a sustainable dividend over the long-term," said Bob Michaleski, Pembina's Chief Executive Officer. "Over the past few years, our team has gone above and beyond to unlock the full potential of our asset base by enhancing our service offering for our customers and, in turn, we have been able to generate substantial value for our shareholders. In 2011, our four business units demonstrated their ability to manage ongoing operations, improve operating margin and keep costs to customers competitive while aggressively pursuing new avenues for growth. This resulted in strong annual results for Pembina and more growth projects on the books than ever before. That, combined with Pembina's proposed acquisition of Provident – a successful and very well-managed company whose assets are complementary to our own – positions Pembina as a leader in the North American energy infrastructure sector. Pending completion of the acquisition, we plan on increasing our monthly dividend rate from $0.13 per share per month (or $1.56 annualized) to $0.135 per share per month (or $1.62 annualized) representing a 3.8 percent increase and reflecting our confidence in the significant operational and financial strength of the combined entity going forward."

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") of the financial and operating results of Pembina Pipeline Corporation ("Pembina" or the "Company") is dated February 15, 2012 and is supplementary to, and should be read in conjunction with, Pembina's audited consolidated annual financial statements for the years ended December 31, 2011 and 2010 ("Consolidated Financial Statements").

Management is responsible for preparing the MD&A. This MD&A has been reviewed and approved by the Audit Committee of Pembina's Board of Directors and its Board of Directors.

This MD&A contains forward-looking statements (see "Forward-Looking Statements & Information" on page 36) and refers to financial measures that are not defined by Canadian Generally Accepted Accounting Principles which have been revised effective January 1, 2010 to converge with International Financial Reporting Standards ("IFRS"). For more information about the measures which are not part of Canadian Generally Accepted Accounting Principles ("Non-GAAP Measures") please see page 33.

About Pembina

Pembina is a diversified energy infrastructure service company that owns and operates assets in western Canada. Pembina transports approximately half of Alberta's conventional crude oil, approximately twenty percent of the natural gas liquids ("NGL") produced in western Canada, and its five oil sands pipelines provide substantial support to the oil sands and heavy oil producers in Alberta. The Company also serves customers through its midstream operations – a network of terminals, storage facilities and marketing services – and natural gas gathering, processing and liquids extraction facilities.

Strategy

Pembina's goal is to provide highly competitive and reliable returns to investors through monthly dividends while enhancing the long-term value of its shares. To achieve this, Pembina's strategy is to:

- Generate value by providing customers with safe, cost-effective, reliable services.
- Diversify Pembina's asset base to enhance profitability. A diverse portfolio provides Pembina with the ability to respond to market conditions, reduce risk and increase opportunities to leverage existing businesses. A priority is placed on developing businesses that support Pembina's core competency – operating crude oil and NGL transportation systems, and gas gathering and processing infrastructure – which allow for expansion, vertical integration and accretive growth.
- Implement growth and conduct operations in a safe and environmentally responsible manner. Growth is expected to occur through expansion of existing businesses, acquisitions and the development of new services. Pembina's investment criteria include pursuing projects or assets that are expected to generate increased cash flow per share and capture long-life, economic hydrocarbon reserves.
- Maintain a strong balance sheet through the application of prudent financial management to all business decisions.

Pembina's business is structured in four units: Conventional Pipelines, Oil Sands & Heavy Oil, Midstream & Marketing and Gas Services, which are described in their respective sections of this MD&A.

History

From September 4, 1997 to September 30, 2010, Pembina was wholly-owned by Pembina Pipeline Income Fund (the "Fund"). On October 1, 2010, the Fund completed its previously announced Plan of Arrangement by virtue of which the business of the Fund was reorganized into a dividend-paying corporation, Pembina Pipeline Corporation (the "Conversion"). Pursuant to the Plan of Arrangement, holders of trust units received one common share of Pembina Pipeline Corporation for each trust unit held. This report reflects the financial and operating performance for the twelve months ending December 31, 2011, and references made in this document primarily refer to the Company, whereas comparative financial and operating performance measures prior to the Conversion primarily refer to the Fund. The Fund's trust units and convertible debentures were previously traded on the Toronto Stock Exchange ("TSX") under the symbols PIF.UN and PIF.DB.B, respectively.

Prior to the Conversion, the Fund paid distributions to the holders of its outstanding trust units and, following the Conversion, the Company pays dividends to the holders of its outstanding common shares, if, as and when declared thereon by the Board of Directors of the Company. When, in this MD&A, references are made to returns on investment or similar concepts over a period of time beginning prior to the Conversion and ending after the Conversion, such references are meant to include any return, including distributions on and fluctuations in the market value of the trust units of the Fund for the relevant period of time prior to the Conversion in addition to any return, including dividends on and fluctuations in the market value of the common shares for the relevant period of time following the Conversion.

For ease of reference, the terms "shares", "shareholders" and "dividends" as used in this MD&A shall include "units", "unitholders" and "distributions" which were previously used in the comparative periods when the trust structure was in place.

IFRS Transition

The Canadian Institute of Chartered Accountants ("CICA") Accounting Standards Board ("AcSB") confirmed in February 2008 that Canadian publicly accountable enterprises will adopt IFRS as issued by the International Accounting Standards Board ("IASB"), effective January 1, 2010 ("Transition Date"). Accordingly, Pembina's Audited Annual Consolidated Financial Statements for the year ended December 31, 2011, including required comparative information, have been prepared in accordance with IFRS 1 – *First-time Adoption of IFRS* ("IFRS 1"), which sets out the requirements for the first time adoption of IFRS. Pembina has adopted IFRS as its primary accounting principles. Previously, Pembina prepared its annual consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") that existed prior to the incorporation of IFRS into the CICA Handbook. Unless otherwise noted, comparative information has been restated for comparative purposes in accordance with IFRS.

Pembina has, from the Transition Date, reconciled its primary IFRS financial statements to Canadian GAAP. Detailed reconciliations of the changes in equity and comprehensive income resulting from the adoption of IFRS are presented in note 35 of the accompanying Consolidated Financial Statements. Financial measures reported in this MD&A have been restated to reflect the transition to IFRS for all periods after the Transition Date. The transition to IFRS has not had a material impact on Pembina's operations, strategic decisions, cash flow and capital expenditures.

Reporting Controls and Procedures

As part of the requirements mandated by the Canadian securities regulatory authorities under National Instrument 52-109-Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"), Pembina's Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO") have evaluated the design and operation of Pembina's disclosure controls and procedures ("DC&P"), as such term is defined in NI 52-109, as at December 31, 2011. Based on that evaluation, the CEO and the CFO concluded that Pembina's DC&P was effective as at December 31, 2011.

The CEO and CFO are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR"), as such term is defined in NI 52-109. These controls are designed to provide reasonable assurance regarding the reliability of Pembina's financial reporting and compliance with GAAP. Pembina's CEO and CFO have evaluated the design and operational effectiveness of such controls as at December 31, 2011. Based on the evaluation of the design and operating effectiveness of Pembina's ICFR, the CEO and the CFO concluded that Pembina's ICFR was effective as at December 31, 2011.

Financial & Operating Overview

(unaudited)

($ millions, except where noted)	3 Months Ended December 31			12 Months Ended December 31		
	2011	2010	2009[2]	**2011**	2010	2009[2]
Revenue	**468.0**	290.2	256.4	**1,676.7**	1,232.2	811.8
Operations	**55.1**	42.3	39.7	**191.9**	155.8	159.2
Product purchases	**308.2**	161.7	127.2	**1,072.1**	735.2	314.4
Operating margin[1]	**104.7**	86.2	89.5	**412.7**	341.2	338.2
Depreciation and amortization included in operations	**19.5**	15.6	11.2	**68.0**	61.7	61.6
Gross profit	**85.2**	70.6	78.3	**344.7**	279.5	276.6
Deduct/(add)						
General and administrative expenses	**21.0**	10.9	18.9	**62.2**	48.6	59.6
Other	**0.8**	0.9	0.2	**1.4**	0.7	0.3
Net finance costs	**20.0**	9.9	15.1	**82.3**	71.8	58.5
Share of profit of investments in equity accounted investee, net of tax	**(1.5)**	(2.6)		**(5.8)**	(9.1)	
Income tax expense (reduction)	**(0.2)**	(3.7)	(8.8)	**38.9**	(8.3)	(3.9)
Earnings for the period	**45.1**	55.2	52.9	**165.7**	175.8	162.1
Earnings per share – basic *(dollars)*	**0.27**	0.34	0.34	**0.99**	1.08	1.09
Earnings per share – diluted *(dollars)*	**0.27**	0.33	0.33	**0.99**	1.07	1.07
EBITDA[1]	**87.0**	79.1	72.5	**364.3**	310.8	279.9
Cash flow from operating activities	**74.3**	54.6	72.0	**287.1**	257.2	224.6
Adjusted cash flow from operating activities[1]	**66.8**	65.0	57.6	**297.5**	252.7	234.7
Dividends	**65.4**	64.6	61.4	**261.2**	255.2	232.3
Dividends per common share *(dollars)*	**0.39**	0.39	0.39	**1.56**	1.56	1.56
Capital expenditures	**147.3**	128.6	59.5	**526.0**	201.9	423.7
Total enterprise value[1] *($ billions)*	**6.6**	4.9	4.0	**6.6**	4.9	4.0
Total assets *($ billions)*	**3.3**	2.9	2.6	**3.3**	2.9	2.6
Average throughput – conventional *(thousands of bpd)*	**422.8**	375.0	379.4	**413.9**	374.0	393.3
Contracted capacity – oil sands *(thousands of bpd)*	**870.0**	775.0	775.0	**870.0**	775.0	775.0
Average processing volume – gas services *(MMcf/d net to Pembina)*	**263.9**	227.8	197.4	**244.5**	220.5	203.0
Barrels of oil equivalent ("BOE") *(thousands)*	**1,336.8**	1,188.0	1,187.3	**1,324.7**	1,185.8	1,202.1

(1) Refer to "Non-GAAP Measures" on page 33.

(2) As Pembina's IFRS transition date was January 1, 2010, 2009 comparative information has not been restated and is presented in accordance with previous Canadian GAAP.

Revenue, net of product purchases, during the fourth quarter of 2011 increased to $159.8 million, compared to $128.5 million during the same period in 2010. Full year revenue, net of product purchases, in 2011 was $604.6 million compared to $497 million in 2010. Increased revenue was driven by strong performance in each of Pembina's four business units, particularly the Midstream & Marketing business which contributed $25.2 million during the fourth quarter of 2011 and $102.0 million during the full year to revenue, net of product purchases, compared to $13.5 million during the fourth quarter of 2010 and $55.5 million during the full year 2010. The approximately 85 percent increase in revenue, net of product purchases, in this business during the fourth quarter and full year of 2011 was primarily due to higher volumes and activity on the Peace Pipeline and Drayton Valley Pipeline systems, stronger commodity prices for the majority of liquid hydrocarbon products and wider margins. The Company's Oil Sands & Heavy Oil business also generated strong revenue of $39.6 million in the fourth quarter and $134.9 million during the full year of 2011 compared to $30.8 million in the fourth quarter and $118.4 million during the full year of 2010. The increase in revenue in this business was largely due to contribution from the Nipisi and Mitsue Pipelines, which began generating returns in the third quarter of 2011.

Revenue, net of product purchases, was $128.5 million in the fourth quarter of 2010 and $497.0 million during the full year, which is comparable to $129.2 million in the fourth quarter of 2009 and $497.4 million during the full year of 2009.

Operating expenses were $55.1 million during the fourth quarter and $191.9 million for 2011 compared to $42.3 million and $155.8 million during the same periods in 2010. The increases were primarily due to enhanced and expanded integrity and maintenance work in anticipation of future increased volumes in Conventional Pipelines, and higher labour, power and operating costs associated with Pembina's growth over the past year.

Operating expenses were $42.3 million during the fourth quarter of 2010 compared to $39.7 million in the fourth quarter of 2009. The increase was primarily due to several integrity initiatives undertaken in the Conventional Pipelines business and increased expenses associated with handling more volumes in the Gas Services business. Operating expenses in 2010 were $155.8 million compared to $159.2 million in 2009. Operating expenses were down slightly year-over-year as costs associated with establishing the Gas Services business and higher power costs within the Oil Sands & Heavy Oil business were offset by diligent cost control, which reduced maintenance and labour costs in the Conventional Pipelines business.

Operating margin totaled $104.7 million during the fourth quarter of 2011 compared to $86.2 million during the fourth quarter of 2010. Full year operating margin in 2011 was $412.7 million compared to $341.2 million for 2010 (operating margin is a Non-GAAP measure, see "Non-GAAP Measures" on page 33). The increase in operating margin in the fourth quarter and full year 2011 compared to the same periods in 2010 was primarily due to increased revenue, as discussed above.

The increases in revenue and operating margin contributed to gross profit of $85.2 million during the fourth quarter of 2011 compared to $70.6 million during the fourth quarter of 2010 and $344.7 million and $279.5 million during the years ended December 31 2011 and 2010, respectively.

General and administrative expenses ("G&A") of $21 million were incurred during the fourth quarter of 2011 compared to $10.9 million during the fourth quarter of 2010. The increase year-over-year for the three month period was largely due to an increase in salaries and benefits for existing and new employees, an increase in both short and long-term incentives and higher rent for new and expanded office space to accommodate the Company's growth and attract and retain the employees necessary to achieve corporate goals. Full year 2011 G&A totaled $62.2 million compared to $48.6 million incurred during 2010. The primary driver of the year-over-year increase in G&A was a $10.3 million increase in share-based incentives for existing and new employees carried at fair value (based on the increased share price) and increased short-term incentives of $3.2 million. The increase was partially offset by a decrease in other G&A expenses. Every $1 increase in share price is expected to increase Pembina's share-based incentive expense by $0.7 million.

Pembina generated earnings before interest, taxes, depreciation and amortization ("EBITDA") of $87.0 million during the fourth quarter of 2011 compared to $79.1 million during the fourth quarter of 2010 (EBITDA is a Non-GAAP measure, see "Non-GAAP Measures" on page 33). Pembina generated EBITDA of $364.3 million during 2011, an increase of 17 percent, compared to $310.8 million during 2010. The increase in quarterly and full year EBITDA was due to strong operating results from each business unit, new assets having been brought on stream and new service offerings during these periods in 2011 compared to the same periods in 2010.

Depreciation and amortization (operations) increased to $19.5 million during the fourth quarter and $68 million for 2011, compared to $15.6 million and $61.7 million during the same periods in 2010. The increase reflects the additional depreciation on new capital additions including the Nipisi and Mitsue Pipeline assets which began in the third quarter of 2011.

The Company's earnings were $45.1 million ($0.27 per share) during the fourth quarter of 2011 compared to $55.2 million ($0.34 per share) during the fourth quarter of 2010. Adjusted earnings were $43.8 million ($0.26 per share) during the fourth quarter of 2011 compared to $44.8 million ($0.27 per share) during the fourth quarter of 2010 (adjusted earnings is a Non-GAAP measure, see "Non-GAAP Measures" on page 33). Earnings totaled $165.7 million ($0.99 per share) for 2011 compared to $175.8 million ($1.08 per share) for 2010. Adjusted earnings were $208.9 million ($1.25 per share) for 2011 compared to $173.5 million ($1.06 per share) during 2010.

Cash flow from operating activities was $74.3 million ($0.44 per share) during the fourth quarter of 2011 compared to $54.6 million ($0.33 per share) during the fourth quarter of 2010. Pembina generated cash flow from operating activities of $287.1 million ($1.71 per share) during 2011 compared to $257.2 million ($1.58 per share) during 2010.

Adjusted cash flow from operating activities was $66.8 million ($0.40 per share) during the fourth quarter of 2011 compared to $65 million ($0.39 per share) during the fourth quarter of 2010 (adjusted cash flow from operating activities is a Non-GAAP measure, see "Non-GAAP Measures" on page 33). Adjusted cash flow from operating activities was $297.5 million ($1.78 per share) during 2011 compared to $252.7 million ($1.55 per share) during 2010.

The increases in cash flow and adjusted cash flow from operating activities were primarily due to overall higher results from operations during the three and twelve months ended December 31, 2011 compared to the respective periods of 2010.

Operating Results

(unaudited)

	3 Months Ended Dec. 31, 2011		3 Months Ended Dec. 31, 2010		**12 Months Ended Dec. 31, 2011**		12 Months Ended Dec. 31, 2010	
($ millions)	**Net Revenue[2]**	**Operating Margin[2]**	Net Revenue[2]	Operating Margin[2]	**Net Revenue[2]**	**Operating Margin[2]**	Net Revenue[2]	Operating Margin[2]
Conventional Pipelines	**75.9**	**40.3**	68.5	42.5	**296.2**	**177.1**	261.6	169.1
Oil Sands & Heavy Oil	**39.6**	**27.2**	30.8	19.9	**134.9**	**90.8**	118.4	78.2
Midstream & Marketing[1]	**25.2**	**23.7**	13.5	12.4	**102.0**	**93.3**	55.5	50.8
Gas Services	**19.1**	**13.0**	15.7	11.4	**71.5**	**49.1**	61.5	43.1
Corporate recovery for leased vehicles		**0.5**				**2.4**		
Total	**159.8**	**104.7**	128.5	86.2	**604.6**	**412.7**	497.0	341.2

(1) Midstream & Marketing revenue is net of $308.2 million and $1,072.1 million in product purchase expense for three and twelve months ended December 31, 2011 ($161.7 million and $735.2 million for the three and twelve months ended December 31, 2010, respectively).

(2) Refer to "Non-GAAP Measures" on page 33.

Conventional Pipelines

	3 Months Ended		**12 Months Ended**	
($ millions, except where noted)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Revenue	**75.9**	68.5	**296.2**	261.6
Operations	**35.6**	26.0	**119.1**	92.5
Operating margin[1]	**40.3**	42.5	**177.1**	169.1
Depreciation and amortization included in operations	**11.1**	7.0	**41.6**	28.4
Gross profit	**29.2**	35.5	**135.5**	140.7
Capital expenditures	**24.3**	13.2	**71.3**	28.8
Average throughput *(thousands of bpd)*	**422.8**	375.0	**413.9**	374.0
Average revenue *($/bbl)*	**1.83**	1.85	**1.84**	1.79
Operating expenses *($/bbl)*	**0.86**	0.71	**0.74**	0.64

(1) Refer to "Non-GAAP Measures" on page 33.

Business Overview

Pembina's Conventional Pipelines business comprises a well-maintained and strategically located 7,500 kilometre ("km") pipeline network that extends across much of Alberta and British Columbia, and transports approximately half of Alberta's conventional crude oil production and approximately twenty percent of the NGL produced in western Canada. The Conventional Pipelines business' primary objective is to generate sustainable operating margins while pursuing opportunities for increased throughput and revenue. Pembina endeavors to maintain and/or improve operating margins through capturing incremental volumes, expanding its pipeline systems, managing revenues and adopting strong discipline measures over operating expenses.

Operational Performance: Throughput

During the fourth quarter of 2011, Conventional Pipelines throughput averaged 422,800 barrels per day ("bpd"), consisting of an average of 260,500 bpd of crude oil, 47,200 bpd of condensate and 115,100 bpd of NGL. The increase in throughput during the fourth quarter of 2011 was largely due to higher production in the Cardium (oil) and Deep Basin Cretaceous (NGL) formations. Throughput during the fourth quarter of 2011 was 12.8 percent higher than the same period in 2010 when average throughput was 375,000 bpd. Full year 2011 throughput averaged 413,900 bpd, compared to 374,000 bpd during 2010. Throughput during the full year of 2011 was substantially higher than the prior year due to increased industry activity in the vicinity of all of Pembina's major pipeline systems, in addition to incremental volumes of approximately 15,000 bpd due to an operational outage on a third-party crude oil pipeline from May to September of 2011.

Fourth quarter 2011 average daily throughput on the Drayton Valley Pipeline system was approximately 115,500 bpd and 184,300 bpd on the Peace Pipeline system compared to approximately 91,800 bpd and 163,100 bpd, respectively, during the same periods in 2010.

During the last week of December 2011, Pembina's Conventional Pipelines transported approximately 450,000 bpd compared to the last week of December 2010, when 400,000 bpd was transported.

Extreme weather in northeastern British Columbia ("B.C.") caused a significant amount of flooding in late June 2011. Pembina proactively shut down its Western System pipeline, which runs from Taylor to Kamloops, B.C., for a period of 15 days to minimize the potential risk of a pipeline incident. During the shutdown, the Company monitored the pipeline by air, land and through its Edmonton Control Centre, conducted integrity inspections, and completed remedial work on the right-of-way before determining it was safe to restart operations. Pembina restarted the Western System pipeline on July 11th and did not experience any material financial impact from this event.

On July 19, 2011 Pembina discovered a spill of between 800 and 1,000 barrels of light sweet crude on its Moosehorn 8 inch gathering pipeline (part of the Swan Hills Pipeline system). The release occurred along Pembina's right-of-way and into muskeg and an unnamed creek, but did not enter any named waterways or sources of drinking water. Pembina plans to replace a 10 km segment of 8 inch pipeline along the right-of-way and expects the pipeline to be back in-service in the first quarter of 2012. An initial claim related to this spill has been filed under Pembina's pollution liability policy. Once work is completed and a final cost is known, a final insurance claim will be made.

Financial Performance

Conventional Pipelines generated revenue of $75.9 million during the fourth quarter of 2011 compared to $68.5 million during the same period in 2010. The quarterly increase was driven by higher volumes on the majority of Pembina's largest systems as discussed in more detail above. Annual revenue in 2011 was $296.2 million compared to $261.6 million in 2010, with the increase over this period also being driven by higher volumes.

During the fourth quarter, operating expenses were $35.6 million compared to the fourth quarter of 2010 when operating expenses totaled $26.0 million. This increase was primarily due to higher labour costs and integrity work conducted on segments of Pembina's Conventional Pipelines to help ensure ongoing pipeline integrity, safety and reliability, and in anticipation of growing throughput. Higher power costs associated with increased throughput also contributed to increased operating expenses during the quarter. Realized gains or losses on power derivatives recorded in this business unit, which provide a hedge for the majority of the power supply and provide greater operating cost certainty, are recognized under finance income. Operating expenses for 2011 were $119.1 million compared to $92.5 million in the same period last year. This increase is attributable to the same factors that impacted fourth quarter 2011 operating expenses. Pembina is committed to being a reliable and responsible operator, and to protecting the health and safety of the communities in which we operate. The Company allocates approximately one third of its annual operating budget to its extensive pipeline and facility integrity management programs.

Operating margin for the fourth quarter of 2011 was $40.3 million, and $177.1 million for the year ended December 31, 2011. This compares to $42.5 million and $169.1 million, respectively, during the same periods of 2010. Higher operating expenses during the fourth quarter negatively impacted operating margin during the period.

Depreciation and amortization included in operations increased from $7.0 million during the fourth quarter of 2010 to $11.1 million during the fourth quarter of 2011 and from $28.4 million during the full year 2010 to $41.6 million during the full year of 2011 primarily due to capital additions in this business unit and a reduction in expected useful lives on certain of Pembina's Conventional Pipelines assets in B.C.

For the three months ended December 31, 2011, gross profit was $29.2 million, compared to $35.5 million during the same period in 2010, due to higher operating expenses incurred during the quarter, as discussed above. Full year 2011 gross profit was $135.5 million compared to $140.7 million during 2010.

Capital expenditures for 2011 within the Conventional Pipelines business totaled $71.3 million, compared to $28.8 million during 2010. The majority of this spending relates to the expansion of certain pipeline assets. For more information, see the section entitled "New Developments & Outlook" starting on page 13.

Oil Sands & Heavy Oil

	3 Months Ended		12 Months Ended	
($ millions, except where noted)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Revenue	**39.6**	30.8	**134.9**	118.4
Operations	**12.4**	10.9	**44.1**	40.2
Operating margin(1)	**27.2**	19.9	**90.8**	78.2
Depreciation and amortization included in operations	**5.0**	5.9	**12.8**	22.7
Gross profit	**22.2**	14.0	**78.0**	55.5
Capital expenditures	**47.9**	77.4	**191.8**	115.6
Capacity under contract *(thousands of bpd)*	**870.0**	775.0	**870.0**	775.0

(1) Refer to "Non-GAAP Measures" on page 33.

Business Overview

With five oil sands pipelines, Pembina plays an important role in supporting Alberta's oil sands and heavy oil industry. Pembina is the sole transporter of crude oil for Syncrude Canada Ltd. (via the Syncrude Pipeline) and Canadian Natural Resources Ltd.'s Horizon Project (via the Horizon Pipeline) to delivery points near Edmonton, Alberta. Pembina also owns and operates the Cheecham Lateral, which transports product to oil sands producers operating southeast of Fort McMurray, Alberta. Pembina has expanded this business by bringing its Nipisi and Mitsue Pipeline projects on-stream in June and July of 2011, which now provide transportation for producers operating in the Pelican Lake and Peace River heavy oil regions of Alberta. The Mitsue Pipeline is the sole provider of diluent by pipeline to this region. This business operates approximately 1,450 km of pipeline and accounts for about 30 percent of the total take-away capacity from the Athabasca oil sands region. These assets operate under long-term, extendible contracts that provide for the flow-through of operating expenses to customers. As a result, operating margin from this business is primarily related to invested capital and is not sensitive to fluctuations in operating expenses or actual throughputs.

Performance

Syncrude Pipeline

The Syncrude Pipeline has a capacity of 389,000 bpd and is fully contracted to the owners of Syncrude Canada Ltd. under an extendible agreement that expires in 2035. Operating margin generated by the Syncrude Pipeline during the fourth quarter and the full year of 2011 was $5.4 million and $24.0 million, respectively, virtually unchanged from $6.6 million and $26.0 million during the same periods in 2010.

Cheecham Lateral

Pembina's Cheecham Lateral has a capacity of 136,000 bpd and is fully contracted to shippers under an agreement that expires in 2032. Operating margin generated by the Cheecham Lateral during the fourth quarter and the full year of 2011 was $1.1 million and $4.5 million respectively, consistent with the results for the same periods in 2010.

Horizon Pipeline

The Horizon Pipeline has a capacity of 250,000 bpd and is fully contracted to Canadian Natural Resources Ltd. under an extendible agreement that expires in 2033. Operating margin generated by the Horizon Pipeline during the fourth quarter and full year of 2011 was $11.6 million and $47.3 million, respectively, compared to $11.8 million and $46.5 million during the same periods in 2010.

Nipisi & Mitsue Pipelines

In June and July of 2011, Pembina completed construction of its Nipisi and Mitsue Pipelines. The Nipisi and Mitsue Pipelines currently have combined take-or-pay capacity of approximately 95,000 bpd. Operating margin generated by these assets in 2011 was $13.7 million.

Financial Performance

Operating expenses in Pembina's Oil Sands & Heavy Oil business were $12.4 million during the fourth quarter of 2011, compared to $10.9 million during the fourth quarter of 2010. Full year 2011 operating expenses were $44.1 million compared to $40.2 million in 2010. The increase in quarterly and year-over-year operating expenses is primarily due to the addition of the Nipisi and Mitsue Pipelines and an increase in power costs on the Syncrude Pipeline.

For the three months ended December 31, 2011, gross profit was $22.2 million compared to $14.0 million during the same period in 2010. Full year 2011 gross profit was $78.0 million compared to $55.5 million in 2010. These increases were primarily due to a reduction in depreciation and amortization expense to reflect the expected life of the underlying oil and gas reserves rather than the terms of the initial contracts for each of the assets in this business unit and the addition of revenue generated by the Nipisi and Mitsue Pipelines.

For the year ended December 31, 2011, capital expenditures within Oil Sands & Heavy Oil totaled $191.8 million, compared to $115.6 million during 2010. The majority of Pembina's 2011 and 2010 investment in this business unit constitutes spending to complete the Nipisi and Mitsue Pipeline projects.

Midstream & Marketing

	3 Months Ended		12 Months Ended	
($ millions)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Revenue	**333.4**	175.2	**1,174.1**	790.7
Operations	**1.5**	1.1	**8.7**	4.7
Product purchases	**308.2**	161.7	**1,072.1**	735.2
Operating margin(1)	**23.7**	12.4	**93.3**	50.8
Depreciation and amortization included in operations	**0.9**	0.5	**3.7**	2.1
Gross profit	**22.8**	11.9	**89.6**	48.7
Capital expenditures	**3.6**	13.9	**110.6**	22.0

(1) Refer to "Non-GAAP Measures" on page 33.

Business Overview

Pembina's Midstream & Marketing business consists of a network of terminals, pipeline-connected storage and hub locations situated at key sites across the Company's conventional pipeline system, including the Pembina Nexus Terminal, as well as a 50 percent non-operated interest in both the Fort Saskatchewan Ethylene Storage Facility and the LaGlace Full Service Terminal. By providing integrated services along the crude oil and NGL value chains, this business has increased the range of services Pembina provides to customers and contributes throughput to the Company's Conventional Pipelines and Oil Sands & Heavy Oil businesses. The value potential associated with terminal, storage and hub assets is dependent on Pembina's ability to: provide connections to both downstream pipelines and end-use markets; understand the value of the commodities transported and terminalled; and provide flexibility and a variety of storage options – all in an environment of a liquid, dynamic, forward commodity market. Pembina actively monitors market conditions to target revenue opportunities.

Performance

Midstream & Marketing recorded significantly higher revenue, net of product purchases, of $25.2 million during the fourth quarter of 2011 compared to $13.5 million during the fourth quarter of 2010, representing an 87 percent increase. Revenue, net of product purchases, for the year ended December 31, 2011 was $102.0 million which is approximately 84 percent higher than the $55.5 million realized during 2010. This was primarily due to higher volumes and activity on the Peace Pipeline and Drayton Valley Pipeline systems, strong commodity prices for the majority of liquid hydrocarbon products and wider margins.

Operating expenses during the fourth quarter of 2011 were $1.5 million compared to $1.1 million in the fourth quarter of 2010. Full year 2011 operating expenses were $8.7 million compared to $4.7 million in 2010. This increase was primarily due to increased expenses associated with the Edmonton, Alberta area assets, as well as a variety of work at Pembina-owned and operated truck terminals.

Operating margin was $23.7 million during the fourth quarter of 2011 compared to $12.4 million during the fourth quarter of 2010. Full year 2011 operating margin totaled $93.3 million compared to $50.8 million in 2010. The increase in operating margin during these periods was largely due to the same factors that contributed to the increase in revenue, net of product purchases, as discussed above.

For the three months ended December 31, 2011, gross profit in this business increased to $22.8 million from $11.9 million during the same period in 2010. For the year ended December 31, 2011, gross profit was $89.6 million compared to $48.7 million in 2010. These increases were a result of the higher operating margin realized during the fourth quarter and full year 2011.

Share of profit from equity accounted investees (Fort Saskatchewan Ethylene Storage Facility) is not included in gross profit but is included in earnings on the Statement of Comprehensive Income. Cash flow from operating activities of $16.9 million in 2011 from this investment was similar to prior periods.

For the year ended December 31, 2011, capital expenditures within the Midstream & Marketing business totaled $110.6 million compared to $22.0 million during 2010. The majority of this spending relates to the acquisition of the terminalling and storage facility near Edmonton, Alberta and the acquisition of linefill for the Peace Pipeline system, both of which occurred in the first quarter of 2011 (see page 18 for further details).

Gas Services

	3 Months Ended		**12 Months Ended**	
($ millions, except where noted)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Revenue	**19.1**	15.7	**71.5**	61.5
Operations	**6.1**	4.3	**22.4**	18.4
Operating margin(1)	**13.0**	11.4	**49.1**	43.1
Depreciation and amortization included in operations	**2.6**	2.1	**9.9**	8.4
Gross profit	**10.4**	9.3	**39.2**	34.7
Capital expenditures	**66.4**	23.1	**136.5**	33.5
Average processing volume *(MMcf/d net to Pembina)*	**263.9**	227.8	**244.5**	220.5
Average BOE *(thousands)*	**44.0**	38.0	**40.8**	36.8

(1) Refer to "Non-GAAP Measures" on page 33.

Business Overview

Pembina's operations also include a growing natural gas gathering and processing business. Located approximately 100 km south of Grande Prairie, Alberta, Pembina's key revenue-generating Gas Services assets - the Cutbank Complex – include 300 km of gathering lines and ownership in three sweet gas processing plants with 360 million cubic feet per day ("MMcf/d") of processing capacity (305 MMcf/d net to Pembina). The Cutbank Complex is connected to Pembina's Peace Pipeline system and serves an active exploration and production area in the Western Canadian Sedimentary Basin ("WCSB"). Pembina is also expanding this business to meet the growing needs of producers throughout west central Alberta who are looking to capture the higher prices associated with NGL. See page 16 for more details.

Performance

Gas Services recorded revenue of $19.1 million during the fourth quarter of 2011 compared to $15.7 million during the same time period in 2010. Full year 2011 revenue was $71.5 million compared to $61.5 million during 2010. This increase in fourth quarter and year-over-year revenue in 2011 primarily reflects higher processing volumes at the Cutbank Complex. Average processing volume, net to Pembina, was 263.9 MMcf/d during the fourth quarter of 2011, approximately 16 percent higher than the 227.8 MMcf/d processed during the fourth quarter of 2010. Average processing volume for the full year 2011 was 244.5 MMcf/d, representing an 11 percent increase over full year 2010 average processing volume of 220.5 MMcf/d.

During the fourth quarter of 2011, operating expenses were $6.1 million, an increase from the $4.3 million spent in the fourth quarter of 2010. For the year ended December 31, 2011, operating expenses totaled $22.4 million, compared to $18.4 million in 2010. These increases were primarily due to handling more volumes at the Cutbank Complex

Gas Services realized operating margin of $13.0 million and $49.1 million during the three and twelve months ending December 31, 2011, respectively, compared to $11.4 million and $43.1 million during the same periods of the prior year. The increase in operating margin during the period and the full year was primarily due to handling more volumes at the Cutbank Complex

For the three and twelve months ended December 31, 2011, gross profit was $10.4 million and $39.2 million, respectively, compared to $9.3 million and $34.7 million, respectively, during the same periods in 2010.

For the year ended December 31, 2011, capital expenditures within Gas Services totaled $136.5 million compared to $33.5 million during 2010 as a result of spending to progress the Musreau Deep Cut Facility and the shallow cut facility at the Cutbank Complex. For more information about these and other new Gas Services projects, see page 16.

Business Environment

The final quarter of the year saw the S&P TSX Composite Index recover from the 2011 lows hit in October to close the quarter essentially flat. That said, after posting gains early in 2011 the Index ended the year down over 10 percent, with significant volatility over periods of the year. The benchmark West Texas Intermediate ("WTI") oil price rallied near year-end to close the year just below USD $100 per barrel, up from October lows of about USD $75 per barrel. Furthermore, low natural gas prices continue to reflect the impact of strong natural gas supply across North America, and what has been a relatively warm winter thus far.

The outlook for the energy infrastructure sector in the WCSB remains positive for all of Pembina's business units. Strong activity levels within the oil sands region represent opportunities for the Company to leverage existing assets to capitalize on additional growth opportunities. Pembina also continues to benefit from the combination of relatively high oil prices and low natural gas prices which has resulted in oil and gas producers extracting the liquids value from their natural gas production and favouring liquids-rich natural gas plays over dry natural gas. Pembina's Conventional Pipelines and Gas Services businesses are well-positioned to capitalize on the increased activity levels in key NGL rich producing basins. Oil and NGL plays being developed in the vicinity of its pipelines include Cardium, Montney, Cretaceous, Duvernay and Swan Hills.

New Developments & Outlook

In 2011, each of Pembina's four business units undertook numerous expansions, as discussed in greater detail below. Capital spending during the year totaled $526 million, the majority of which was directed towards the Nipisi heavy oil and Mitsue diluent pipeline projects, a $57 million acquisition of a midstream terminal facility, various expansions on Pembina's conventional pipelines, the purchase of linefill for the Peace Pipeline, and expenditures related to the Musreau Deep Cut Facility and the shallow cut expansion at the Cutbank Complex.

Pembina's Board of Directors has approved a $550 million capital spending plan for 2012, the largest in the Company's history. Pembina expects to target the majority of the expenditure to its Gas Services and Conventional Pipelines businesses, including the previously announced Northern NGL Expansion as well as the Resthaven and Saturn gas plants.

Pending successful closing of Pembina's proposed acquisition of Provident Energy Ltd. (TSX: PVE, PVE.DB.E, PVE.DB.F, NYSE: PVX) ("Provident"), Pembina's aggregate capital spending plan for 2012 could be increased to approximately $700 million. See below for further details.

Proposed Acquisition of Provident

Pembina announced on January 16, 2012 that it had entered into an agreement with Provident (the "Arrangement Agreement") for Pembina to acquire all of the issued and outstanding common shares of Provident (the "Provident Shares") by way of a plan of arrangement under the Business Corporations Act (Alberta) (the "Arrangement") for a total value of approximately $3.8 billion (based on Pembina's January 13, 2012 closing share price of $27.90 on the TSX and including the assumption of Provident's outstanding debt and convertible debentures).

Transaction Description

Under the terms of the Arrangement Agreement, Provident shareholders will receive 0.425 of a Pembina common share for each Provident Share held (the "Provident Exchange Ratio"). After completion of the proposed transaction the combined assets and employees will operate under the Pembina name and will be led by Bob Michaleski, President and Chief Executive Officer of Pembina, and a combination of Pembina's and Provident's executive teams.

Once completed, the proposed transaction is expected to increase Pembina's cash flow per share and dividends per share, and reduce its dividend payout ratio. Upon the successful completion of this transaction Pembina intends to increase its monthly dividend rate from $0.13 per share per month (or $1.56 annualized) to $0.135 per share per month (or $1.62 annualized), representing a 3.8 percent increase and reflecting management's confidence in the significant operational and financial strength of the combined entity going forward.

Under the Arrangement Agreement, Pembina will also assume all of the rights and obligations of Provident relating to: (i) the 5.75% convertible unsecured subordinated debentures of Provident maturing December 31, 2017, and (ii) the 5.75% convertible unsecured subordinated debentures of Provident maturing December 31, 2018.

The Combined Entity

The proposed transaction would integrate Pembina's energy transportation and gas processing businesses with Provident's suite of services including NGL extraction, fractionation, storage, transportation and logistics. Pembina's expanded footprint will provide greater access to natural gas liquids markets across North America, and will allow the Company to offer customers a significantly expanded range of energy services.

The combined entity will create one of the largest publicly traded energy infrastructure companies in Canada with an estimated enterprise value of approximately $10 billion, offering the following benefits for shareholders of both Pembina and Provident:

- Scale and Scope: A substantially larger, and more diversified portfolio of businesses across the energy infrastructure value chain, with a cash flow stream which is predominately fee-based;
- Complete Value Chain: A suite of services available to customers through the combination of Pembina's liquids transportation, gas gathering, processing and liquids extraction, and midstream and marketing segments and Provident's capabilities in NGL mainline extraction, fractionation, storage, transportation and logistics permitting both a diversification of business and strengthening the value proposition for its shareholders and customers;
- Key Growth Areas: Extensive energy infrastructure businesses located in key growth regions including: Montney, Duvernay, Alberta Deep Basin, Pelican Lake heavy oil, Athabasca oil sands, Cardium, Swan Hills, Bakken, Marcellus and Utica;
- Expanded Footprint: Greater access to liquid hydrocarbons as well as increased capability to store, process and market barrels across key North America hubs including Edmonton, Sarnia and Mont Belvieu. The pro forma company will have operations in key market areas for NGL and crude oil in close proximity to pipelines, rail and truck facilities, storage, fractionation, petrochemical and refining customers;
- Strong Leadership Team: An experienced management team with a strong focus on being a responsible, reliable operator and a trusted member of the community;
- Substantial Growth Opportunities: A larger entity capable of pursuing more complex growth projects at an accelerated pace including an aggregate capital program of approximately $700 million of announced spending

in 2012 (Pembina: $550 million, Provident: $150 million). The combined capital program is focused on fee-based opportunities. Major near-term projects include:

- Saturn and Resthaven liquids extraction facilities;
- Peace and Northern NGL pipeline expansion;
- Redwater liquids storage development; and
- Redwater fractionator capacity expansion.

- Strong Synergies: The combined entities will generate substantial synergies:
    - The ability to leverage technical, commercial and operational skills from both Pembina and Provident over the combined asset base, achieving cost savings and operating efficiencies;
    - Synergies that will be realized by more fully connecting, integrating and utilizing the current and future asset bases of both companies;
    - Corporate cost synergies through the consolidation of head offices, the decrease of Provident debt service costs, and the elimination of costs associated with Provident's public company costs; and
    - Capital efficiencies through the allocation of capital expenditures to the highest return projects.
- Superior Financial Platform: The pro forma company will generate a diversified stable cash flow stream and enjoy a very strong balance sheet with pro forma 2011 senior debt to EBITDA of approximately 2.4x.

Canadian and U.S. Tax Considerations for Provident Shareholders

The Arrangement Agreement has been structured to allow Provident shareholders to receive Pembina shares generally on a tax-deferred basis for Canadian income tax purposes. In addition, the Arrangement Agreement has been structured so that the Arrangement will qualify as a tax-free transaction for U.S. federal income tax purposes. If the Arrangement qualifies as a tax-free transaction, Provident shareholders who receive Pembina shares will not be required to recognize gain and will not be permitted to recognize loss. However, there can be no assurance that the U.S. Internal Revenue Service will not challenge the treatment of the Arrangement as a tax-free transaction.

Transaction Approval Process

The Arrangement is subject to the approval of Provident shareholders, Pembina shareholders and the Court of Queen's Bench of Alberta. Further information regarding the proposed transaction will be contained in a joint information circular that Pembina and Provident will prepare, file and mail in due course to their respective shareholders in connection with the special meetings of shareholders of each of Pembina and Provident, which are each scheduled to take place on March 27, 2012. In addition to shareholder and court approvals, the proposed transaction is subject to applicable regulatory approvals and the satisfaction of certain other closing conditions customary in transactions of this nature, including compliance with the Competition Act (Canada) and the acceptance of the TSX. If approved by shareholders, closing of the transaction is expected to occur as soon as possible thereafter subject to regulatory approval.

Major Project Breakout

($ millions) Project	Business unit	2012 Capital budget	Remaining committed capital	Estimated in-service date
Resthaven Facility	Gas Services / Conventional Pipelines	115	115	Q4 – 2013
Saturn Facility	Gas Services / Conventional Pipelines	125	75	Q4 – 2013
NGL Expansion(1)	Conventional Pipelines	55	45	2012 – 2013
Truck Terminals	Midstream & Marketing	35	15	2013+
Crude Expansion	Conventional Pipelines	30		Q3 – 2013
Musreau Shallow Cut Expansion	Gas Services	25		Q3 – 2012
Other		165		2012 – 2013
Total		550	250	

(1) Provided Pembina secures adequate customer support.

The table above lists the suite of projects and committed capital under Pembina's 2012 capital spending plan. Each project is discussed in more detail below.

Gas Services Business Expansions

Pembina continues to see significant growth opportunities resulting from the trend towards liquids-rich resource play gas drilling and the extraction of valuable NGL from gas in the WCSB. In 2011, Pembina's Gas Services team focused on expanding this line of business, capitalizing on its experience and expertise, and building out its capacity to extract liquids from the gas stream and transport them to market using Pembina's existing conventional pipeline network. This has resulted in four expansion projects and demonstrates the strength of the Company's integrated approach.

Two of these projects are expansions of Pembina's existing assets at its Musreau gas plant, one of the three plants that make up the Company's Cutbank Complex:

- The Musreau Deep Cut Facility; and
- The Musreau Shallow Cut Expansion.

The other two projects diversify Pembina's Gas Services operations and provide access into new geographic regions that are seeing similar increases by producers in development and the need for gas processing:

- The Resthaven Facility in the Resthaven area of Alberta; and
- The Saturn Facility in the Berland area of Alberta.

These four expansions are expected to bring Pembina's gas processing capacity to 890 MMcf/d (net), including enhanced NGL extraction capacity of approximately 535 MMcf/d (net), which would be processed largely on a contracted, fee-for-service basis and result in approximately 45,000 bpd of incremental NGL to be transported for additional toll revenue on Pembina's conventional pipelines by the end of 2013.

Expansion at the Cutbank Complex: Musreau Deep Cut Facility

Construction of Pembina's Musreau Deep Cut Facility, a new 205 MMcf/d ethane extraction facility and the related 10 km pipeline, is substantially complete. Pembina is nearing the final commissioning phase and start-up of the facility will occur on February 15, 2012, approximately five months behind its expected scheduled commissioning date of October 2011. This delay is largely the result of constraints related to the confined worksite at the facility. This new $90 million plant will deliver an ethane mix stream to Pembina's Peace Pipeline. Pembina has contracted approximately 80 percent of the planned capacity at the Musreau Deep Cut Facility and expects to contract the remaining capacity under terms designed to provide Pembina with cash flow certainty. Based on certain assumptions, once on-stream and at full capacity, the Musreau Deep Cut Facility is expected to provide Pembina with approximately $12 million to $15 million of additional EBITDA annually, as well as up to 13,000 bpd of liquids which Pembina will transport on its conventional pipelines and for which it will receive additional toll revenue (see "Forward-Looking Statements & Information" on page 36).

Expansion at the Cutbank Complex: Musreau Shallow Cut Expansion

Pembina also plans to expand Musreau's shallow cut gas processing capability by 50 MMcf/d at an estimated cost of $26 million. Once the expansion is complete, the Cutbank Complex is expected to have an aggregate raw gas processing capacity of 410 MMcf/d (355 MMcf/d net to Pembina), an increase of 16 percent net to Pembina. Subject to regulatory and environmental approval, the expansion is expected to be in-service by mid-2012. Pembina has entered into contracts with a minimum term of five years with area producers for the entire capacity of the expansion on a fee-for-service basis.

Expansion into Resthaven Region: the Resthaven Facility

Pembina announced on October 13, 2011 that it had entered into agreements to develop a combined shallow cut and deep cut NGL extraction facility (the "Resthaven Facility") by modifying and expanding an existing gas plant. Once operational, the initial phase of the Resthaven Facility will have a gross capacity of 200 MMcf/d and 13,000 bpd of liquids extraction capability, with ultimate processing capacity of 300 MMcf/d and 18,000 bpd of liquids extraction capability. Pembina plans to construct a 44 km, 6 inch diameter NGL pipeline to transport the extracted NGL from the Resthaven Facility to Pembina's Peace Pipeline, which delivers product into Edmonton, Alberta. Once completed, Pembina will own approximately 65 percent of the Resthaven Facility and will own 100 percent of the NGL pipeline.

Based on certain assumptions, Pembina estimates that the Resthaven Facility, associated NGL pipeline, and storage facilities will cost approximately $230 million (net to Pembina) and will contribute annual EBITDA of $30 to $40 million (including expected additional pipeline tolls) (see "Forward-Looking Statements & Information" on page 36). Subject to regulatory and environmental approvals, Pembina expects these new facilities to be in-service in late 2013. Pembina's investment in the Resthaven Facility is supported by long-term firm service agreements with two of the major area producers while the NGL pipeline is underpinned by long-term service agreements with the Resthaven Facility owners.

As at the beginning of February 2012, Pembina has executed a Construction Agreement and has ordered long lead equipment for the project. Other activities related to the project include stakeholder consultation, environmental planning, route selection, engineering, and right-of-way surveying.

Expansion into Berland Region: the Saturn Facility

Pembina announced on October 28, 2011 that it plans to construct, own and operate a 200 MMcf/d enhanced NGL extraction facility (the "Saturn Facility") and associated NGL and gas gathering pipelines in the Berland area of west central Alberta.

The Saturn Facility will be connected to Talisman Energy Inc.'s ("Talisman") Wild River and Bigstone gas plants through existing and newly constructed gas gathering lines. Once operational, Pembina expects the Saturn Facility will have the capacity to extract up to 13,500 bpd of liquids. Pembina plans to construct an 83 km, 8 inch NGL pipeline to transport the extracted NGL from the Saturn Facility to Pembina's Peace Pipeline.

Pembina expects the Saturn Facility, associated NGL and gas gathering pipelines and storage to cost approximately $200 million and, based on certain assumptions, contribute annual EBITDA of approximately $30 million (including expected additional pipeline tolls) (see "Forward-Looking Statements & Information" on page 36). Subject to regulatory and environmental approval, Pembina expects the Saturn Facility and associated pipelines to be in-service in the fourth quarter of 2013 and has entered into a long-term, firm service agreement with Talisman.

As of the beginning of February 2012, Pembina has ordered 80 percent of the major, long lead equipment for the project. Environmental field assessments have been completed, stakeholder consultation is ongoing, final routing and work space requirements are being evaluated and regulatory meetings are underway.

Conventional Pipelines Development

Liquids Rich Natural Gas: Expansion of Peace and Northern Pipelines

On November 9, 2011, Pembina announced plans to expand its NGL throughput capacity on its Peace and Northern Pipelines (together the "Northern NGL System") by 55,000 bpd (the "NGL Expansion") to accommodate increased customer demand resulting from strong drilling results and increased field liquids extraction by area producers.

The NGL Expansion will require Pembina to install five new pump stations and upgrade five existing pump stations. Pembina expects the NGL Expansion will cost approximately $100 million and is subject to reaching long-term commercial arrangements with its customers and regulatory and environmental approvals. Pembina expects 20,000 bpd of the NGL Expansion can be brought into service by the end of 2012 and the remaining 35,000 bpd by the end of 2013.

Pembina's Northern NGL System is strategically located across liquids rich natural gas production areas in the WCSB and serves producers in the Deep Basin, Montney, Cardium and emerging Duvernay Shale plays. Currently, the Northern NGL System's capacity is 115,000 bpd. As at December 31, 2011, average daily throughput on the Northern NGL System was approximately 99,000 bpd. Once completed, the proposed NGL Expansion will increase capacity on the Northern NGL System by 48 percent to 170,000 bpd.

Pembina has existing long-term contracts in place for a portion of the capacity on its Northern NGL System and has entered into several new long-term firm service incentive arrangements for additional capacity on the system. Combined, the existing and new contracts have secured 55 percent of the 170,000 bpd capacity as at February 1, 2012. Pembina continues to consult with its customers to increase the volumes under long-term, firm service incentive contracts to underpin the NGL Expansion.

Pembina believes its plans for the NGL Expansion can be completed very cost-effectively by upgrading and modifying existing infrastructure where possible and will reduce environmental and community impact by using existing right-of-ways.

Drayton Valley Area

In the area of the Cardium formation of west central Alberta, Pembina increased the capacity of an existing 8 inch 42 km section of pipeline that transports crude oil between Willesden Green and Buck Creek, Alberta. This expansion, which was put into service in December of 2011, has increased the capacity of the line from 12,000 bpd to approximately 37,000 bpd. The incremental capacity of the Willesden Green loop will also accommodate incremental volumes from Pembina's new Baptiste Truck Terminal and provide improved service options to producers in the O'Chiese to Rocky Mountain House area of Alberta. By the second quarter of 2012, Pembina expects to complete the refurbishing of its Calmar booster station to add 50,000 bpd of capacity to the Drayton Valley mainline, bringing the total capacity of the system to 190,000 bpd. The Drayton Valley system is currently moving 125,000 bpd as of the beginning of February 2012.

Edson Area

During the first quarter of 2011, Pembina announced that it would extend the reach of its conventional pipeline network to provide liquids transportation solutions to producers in the greater Edson, Alberta area.

Pembina has completed the re-activation and re-certification of an existing 6 inch line from Windfall Junction on its Peace Pipeline system to Edson at an estimated capital cost of $15 million, and began deliveries on October 15, 2011. This pipeline provides transportation options for producers exploring for liquids-rich gas in Deep Basin Cretaceous plays, including Cardium oil opportunities south of Edson. The re-commissioned pipeline is underpinned by a long-term transportation agreement with an area producer for approximately 5,000 bpd and has an initial capacity of approximately 12,500 bpd with an ultimate capacity of approximately 17,500 bpd. Due to high levels of industry activity in the greater Edson area, Pembina expects additional capacity and tie-in opportunities on this new line segment.

Oil Sands & Heavy Oil

In June and July of 2011, Pembina completed its Nipisi and Mitsue Pipelines to service the Pelican and Peace River heavy oil regions of Alberta. The Company's Oil Sands & Heavy Oil team is assessing the feasibility of expanding these pipelines and is in active conversations with existing and potential customers regarding various expansion scenarios to accommodate growing production from these regions.

Midstream & Marketing: Development of the Pembina Nexus Terminal and Truck Terminal Expansion Plans

In early 2011, Pembina acquired terminalling and storage facilities located near Edmonton, Alberta. The $57 million acquisition included more than 300,000 barrels of existing storage capacity and sufficient bare land to develop and significantly expand storage capacity as customer demand grows. The assets are interconnected via pipelines to other Pembina infrastructure, as well as refineries and downstream terminals, and will enable Pembina to create tailored products and services for customers while facilitating growth opportunities for its other business units. In addition, the assets will form a cornerstone of the Pembina Nexus Terminal ("PNT"), which has been designed to connect key infrastructure in the Edmonton – Fort Saskatchewan – Namao, Alberta area. Pembina envisions that PNT will act as, among other things, a key distribution hub to serve the growing demand for diluent by customers in the oil sands and heavy oil sector in both the Fort McMurray and Peace River, Alberta regions. At the end of the fourth quarter of 2011, Pembina completed initial work to increase the interconnectivity of the terminal to add value for both upstream and downstream customers. In the future, Pembina anticipates undertaking additional activities to further increase access to the terminal which would be completed over time, based on market demand.

On September 13, 2011 Pembina announced plans to expand services at a number of its existing truck terminals and construct new full-service terminals that focus on emulsion treating (separating oil from impurities to meet shipping quality requirements), produced water handling and water disposal. In addition to earning fees for these services, Pembina's truck terminals will secure volumes for its pipeline systems which will generate additional pipeline toll revenue.

Pembina's current truck terminal assets include twelve clean oil facilities and an interest in both the LaGlace Full Service Terminal and the Rimbey Truck Terminal – all of which are connected to Pembina's conventional pipeline systems. In addition, Pembina has completed construction of its Baptiste Truck Terminal, which serves Cardium producers in the Willesden Green area, as discussed above.

Pembina entered the full service truck terminal business in 2008 through a joint venture with an industry partner to construct the LaGlace Full Service Terminal. Increasing the Company's truck terminal network is part of an overall strategy focused on securing volumes for Pembina's conventional pipeline network, and extending its suite of value-added services to existing and potential customers. This initiative is another example of the Company's vertical integration strategy.

Pembina has numerous opportunities across its conventional pipeline network to service constrained and developing areas and its initial capital expenditures, which are subject to regulatory and environmental approvals, will be directed towards truck terminals that service Cardium, Montney, Deep Basin and Peace River oil producers as well as PNT.

Fort Saskatchewan Ethylene Storage Facility

Three of the five ethylene storage caverns in Pembina's Storage Facility in Fort Saskatchewan are currently out of service and it is unlikely those caverns will be put back into ethylene storage service. While alternative uses are being considered, no assurance that future economic benefits from such out-of-service caverns (or their disposal) can be given at this time. Pembina has entered into agreements to wash a new ethylene storage cavern and does not expect a reduction in cash flow. As a result of such agreements, Pembina has recognized a benefit from equity accounted investees and de-recognized a portion of the investment values related to such out of service caverns in approximately the same amounts. This will reduce reported share of profit from equity accounted investees but not cash flow from operating activities while the new cavern is under construction.

Dividends

Based on certain assumptions, and subject to compliance with applicable law, Pembina expects to increase its monthly dividend rate from $0.13 per share per month (or $1.56 annualized) to $0.135 per share per month (or $1.62 annualized) representing a 3.8 percent increase, pending succesful closing of the prosposed acquisition of Provident. In addition, Pembina is committed to providing increased shareholder returns over time by providing stable dividends and, where appropriate, further increases in Pembina's dividend, subject to compliance with applicable laws and the approval of Pembina's Board of Directors. Pembina has a history of delivering dividend increases (or, prior to the Conversion, cash distributions) once supportable over the long term by the underlying fundamentals of Pembina's businesses as a result of, among other things, accretive growth projects or acquisitions (see "Forward-Looking Statements & Information" on page 36).

Dividends are payable if, as, and when declared by Pembina's Board of Directors and the amount and frequency of dividends declared and payable is at the discretion of the Board, which will consider earnings, capital requirements, the financial condition of Pembina and other relevant factors.

Eligible Canadian investors may benefit from an enhanced dividend tax credit afforded to the receipt of dividends, as compared to distributions of income, depending on individual circumstances. Dividends paid to eligible U.S. investors should qualify for the reduced rate of tax applicable to long-term capital gains but investors are encouraged to seek independent tax advice.

NON-OPERATING EXPENSES AND OTHER INCOME

G&A

G&A expenses of $21 million were incurred during the fourth quarter of 2011 compared to $10.9 million during the fourth quarter of 2010. The increase year-over-year for the three month period was due to an increase in salaries and benefits for existing and new employees, an increase in both short and long-term incentives and increased rent for new and expanded office space. Full year 2011 G&A totaled $62.2 million compared to $48.6 million incurred during 2010. The primary driver of the year-over-year increase in G&A was a $10.3 million increase in share-based incentives for existing and new employees carried at fair value (based on the increased share price) and increased short-term incentives of $3.2 million. The increase was partially offset by decreases in other G&A expenses. Every $1 increase in share price is expected to increase Pembina's share-based incentive expense by $0.7 million.

Depreciation & Amortization (operational)

Depreciation and amortization was $19.5 million during the fourth quarter 2011 compared to $15.6 million during the same period of 2010. On a full year basis, depreciation and amortization was $68 million in 2011 compared to $61.7 million in 2010. The increase in depreciation was largely due to additional depreciation for capital additions, including depreciation for the Nipisi and Mitsue Pipelines which totaled $5.8 million in 2011. This was slightly offset by a reduction of depreciation expenses on Oil Sands & Heavy Oil assets to reflect the expected life of the underlying oil and gas reserves rather than the terms of the initial contracts.

Net Finance Costs (including unwinding of discount rates)

Net finance costs in the fourth quarter of 2011 were $20.0 million compared to $9.9 million in the fourth quarter of 2010. The net increase of $10.1 million relates to a $2.4 million increase in convertible debenture interest expense, a $2.6 million increase in long-term debt interest expense, a $0.7 million increase in unwinding of the discount rate expense and a $5.7 million decline in the fair value of financial derivatives, offset by a $1.2 million increase in realized gains on power derivatives. Annual net finance costs in 2011 were $82.3 million compared to $71.8 million in 2010. The net increase of $10.5 million for the full year relates to an increase in finance income of $5.3 million (mostly due to an increase in the realized gain on power derivatives) offset by an increase in finance costs of $15.8 million. The increase in finance costs is due to an increase in convertible debenture interest expense ($14.4 million) as a result of a full year of interest on the 5.75% convertible unsecured subordinated debentures issued on November 24, 2010, unwinding of discount rate expense ($1.8 million), long-term debt interest expense ($0.7 million) and a decline in mark to market unrealized losses on financial derivatives ($0.9 million).

Income Tax Expense

Deferred income taxes arise from differences between the accounting and tax basis of assets and liabilities. An income tax reduction of $0.2 million was recorded in the fourth quarter of 2011 compared to an income tax reduction of $3.7 million in the fourth quarter of 2010. On a full year basis, income tax expense was $38.9 million in 2011 compared to an income tax reduction of $8.3 million for 2010. The increased income tax expense for the fourth quarter and year ended 2011 is primarily due to the Conversion of the Fund to corporate structure and the resultant loss of tax efficiencies. See page 4 for further information on the Conversion.

Pension Liability

Pembina maintains a defined contribution plan and non-contributory defined benefit pension plans covering employees and retirees. The defined benefit plans include a funded registered plan for all employees and an unfunded supplemental retirement plan for those employees affected by the Canada Revenue Agency maximum pension limits. At the end of 2011, the pension plans carried a deficit of $16.9 million, compared to a deficit of $6.0 million at the end of 2010. At December 31, 2011, plan obligations amounted to $105.2 million (2010: $94.5 million), compared to plan assets of $89.4 million (2010: $89.6 million). In 2011, the pension plans' expense was $4.8 million (2010: $4.7 million). Contributions to the pension plans totaled $8.0 million in each 2010 and 2011.

In 2012, contributions to the pension plans are expected to be $10.0 million and pension plans' expenses are anticipated to be $5.9 million. Management anticipates a long-term return on the pension plans' assets of 6.07 percent and an annual increase in compensation of 4 percent, which are consistent with current industry standards.

Liquidity & Capital Resources

	12 Months Ended	
($ millions)	**Dec. 31, 2011**	Dec. 31, 2010
Working Capital	**(342.1)[(1)]**	125.0
Variable rate debt[(2)]		
Bank debt	**314.9**	246.2
Variable rate debt swapped to fixed	**(200.0)**	(200.0)
Total variable rate debt outstanding (average rate of 1.85%)	**114.9**	46.2
Fixed rate debt[(2)]		
Senior secured notes	**58.0**	66.0
Senior unsecured notes	**642.0**	642.0
Senior unsecured term debt	**75.0**	75.0
Senior unsecured medium term note	**250.0**	
Variable rate debt swapped to fixed	**200.0**	200.0
Total fixed rate debt outstanding (average rate of 5.49%)	**1,225.0**	983.0
Convertible debentures[(2)]	**299.8**	300.0
Finance lease liability	**5.6**	4.5
Total debt and debentures outstanding	**1,645.3**	1,333.7
Cash and unutilized debt facilities	**235.1**	429.2

(1) Current assets less current liabilities, including $310 million of current, non-revolving unsecured credit facilities expected to be renewed in 2012.
(2) Excluding amortization.

Pembina anticipates cash flow from operating activities will be more than sufficient to meet its short-term operating obligations and fund its targeted dividend level. In the medium-term, funds required for capital projects are expected to be sourced from unutilized debt facilities totaling $235.1 million as at December 31, 2011 and Pembina believes, based on its successful access to financing in the debt and equity markets during the past several years that it would likely continue to have access to funds at attractive rates. Additionally, Pembina has reinstated its Premium Dividend™ and Dividend Reinvestment Plan ("DRIP") effective as of the January 25, 2012 record date to help fund its ongoing capital program (see page 25 for further details). Management remains satisfied that the leverage employed in Pembina's capital structure is sufficient and appropriate given the characteristics and operations of the underlying asset base.

Management may make adjustments to Pembina's capital structure as a result of changes in economic conditions or the risk characteristics of the underlying assets. To maintain or modify Pembina's capital structure in the future, Pembina may renegotiate new debt terms, repay existing debt and seek new borrowing and/or issue equity.

Pembina's credit facilities at December 31, 2011 consisted of an unsecured $500 million revolving credit facility due July, 2012 and an operating facility of $50 million due July, 2012. Borrowings on the revolving credit facility bear interest at prime lending rates or Bankers' Acceptances rates plus 0.35 percent to 1.35 percent. Margins on the Bankers' Acceptances rate are based on the credit rating of Pembina's senior unsecured debt. Current borrowings on the operating facility bear interest at prime lending rates plus 0.35 percent to 2.35 percent or Bankers' Acceptances rates plus 1.35 percent to 3.35 percent. There are no repayments due over the term of these facilities. As at December 31, 2011, Pembina had $314.9 million drawn on bank debt (including $1.1 million in letters of credit) leaving $235.1 million of unutilized debt facilities (bank indebtedness as at December 31, 2011: $0.7 million) on the $550 million of established bank facilities. Other debt includes $58 million in fixed rate senior secured notes due 2017; $75 million in senior unsecured term debt due 2014; $175 million in fixed rate senior unsecured notes due 2014; $267 million in senior unsecured notes due 2019; $200 million in fixed rate senior unsecured notes due 2021; and, $250 million in medium term notes due 2021. At December 31, 2011, Pembina had loans and borrowing (excluding amortization, letters of credit and finance lease liabilities) of $1,338.1 million. Pembina's senior debt to total capital at December 31, 2011 was 52 percent.

In November 2010, Pembina announced it filed a Short Form Base Shelf Prospectus with Canadian regulatory authorities in each of the provinces of Canada. Under provisions detailed in the Short Form Base Shelf Prospectus, Pembina may offer and issue, from time-to-time: (i) shares; (ii) any bonds, debentures, notes or other evidences of indebtedness of any kind, nature or description of Pembina ("Debt Securities"); (iii) warrants to purchase shares and warrants to purchase Debt Securities; and (iv) subscription receipts of Pembina (collectively, the "Securities") of up to $1 billion aggregate initial offering price of Securities during the 25-month period that the shelf prospectus is valid. Securities may be offered separately or together, in amounts, at prices and on terms to be determined based on market conditions at the time of sale and set forth in one or more shelf prospectus supplements. As of December 31, 2011, Pembina had $450 million remaining under Short Form Base Shelf Prospectus.

Pembina considers the maintenance of an investment grade credit rating as important to its ongoing ability to access capital markets on attractive terms. On January 18, 2012, Standard & Poor's placed its ratings, including its 'BBB+' long-term corporate credit rating, on Pembina on Credit Watch with negative implications and DBRS placed the BBB (high) ratings of the Senior Unsecured Notes and the 7.38 percent Senior Secured Notes of Pembina Under Review with Negative Implications, following Pembina's announcement regarding its proposed acquisition of Provident (see page 14). These ratings are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

Capital Expenditures

	3 Months Ended		12 Months Ended	
($ millions)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Development capital				
Conventional Pipelines	**24.3**	13.2	**71.3**	28.8
Oil Sands & Heavy Oil	**47.9**	77.4	**191.8**	115.6
Midstream & Marketing	**3.6**	13.9	**110.6**	22.0
Gas Services	**66.4**	23.1	**136.5**	33.5
Corporate/other projects	**5.1**	1.0	**15.8**	2.0
Total development capital	**147.3**	128.6	**526.0**	201.9

During the fourth quarter of 2011, capital expenditures were $147.3 million compared to $128.6 million during the same three month period in 2010. The increase primarily reflects investments made to expand several of Pembina's Conventional Pipelines and to progress construction of the Musreau Deep Cut Facility at the Cutbank Complex in Gas Services.

During 2011, capital expenditures totaled $526 million, the majority of which was directed towards the Nipisi heavy oil and Mitsue diluents pipeline projects, the $57 million midstream terminal acquisition, the $33 million purchase of linefill for the Peace Pipeline System, various expansions on Pembina's conventional pipelines, and the Musreau Deep Cut Facility.

Pembina's Board of Directors approved a capital spending plan for 2012 of approximately $550 million, with the majority of the expenditures targeted at projects in the Company's Conventional Pipelines and Gas Services businesses. Pembina's 2012 capital spending plan is approximately 17 percent higher than its 2011 capital expenditures (net of the $57 million midstream terminal acquisition) and represents the largest in the Company's history.

- The Conventional Pipelines business expects to invest approximately $210 million in 2012, with the majority allocated to expanding the Alberta-based pipeline systems.
- Pembina's Gas Services business plans to spend approximately $235 million in capital in 2012 with $200 million being directed towards the Saturn and Resthaven enhanced liquids extraction facilities (see page 16 for further details).
- The Midstream & Marketing business intends to invest $70 million in 2012 with $35 million being directed towards expanding Pembina's presence in the full-service truck terminal business.

- The Oil Sands & Heavy Oil business' capital spending plan for 2012 is approximately $30 million which includes $17 million of capital to finalize the Nipisi and Mitsue Pipelines (this capital was included in the $400 million estimated total project cost, but has not yet been spent).

Contractual Obligations

($ thousands)		Payments Due By Period			
Contractual Obligations	**Total**	**Less than 1 year**	**1 - 3 years**	**4 - 5 years**	**After 5 years**
Office and vehicle leases	74,494	8,784	12,900	8,540	44,270
Loans and borrowings(1)	1,338,117	321,720	279,811	19,586	717,000
Convertible debentures(1)	299,780				299,780
Construction commitments	364,315	261,200	103,115		
Provisions	416,153	10,720	8,463	1,087	395,883
Total contractual obligations	2,492,859	602,424	404,289	29,213	1,456,933

(1) Excluding amortization costs and finance leases included under "office and vehicle leases".

Pembina is, subject to certain conditions, contractually committed to the construction and operation of the Musreau Deep Cut Facility at its Cutbank Complex, the Musreau Shallow Cut Expansion, the Saturn Facility and the Resthaven Facility.

See "Forward-Looking Statements & Information" on page 36 of this report.

Critical Accounting Estimates

The preparation of the Financial Statements in conformity with IFRS requires management to make judgments, estimates and assumptions that are based on the circumstances and estimates at the date of the financial statements and affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Judgments, estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about judgments, assumptions and estimation uncertainties that have significant risk of resulting in a material adjustment within the current and next financial years are included in the following notes:

1. Defined benefit obligations

The calculation of the defined benefit obligation is sensitive to many estimates, but most significantly the discount rate applied.

2. Provisions and contingencies

Provisions recognized are based on management's judgment about assessing contingent liabilities and timing, scope and amount of liabilities. Management uses judgment in determining the likelihood of realization of contingent assets and liabilities to determine the outcome of contingencies.

Based on the long-term nature of the decommissioning provision, the biggest uncertainties in estimating the provision are the discount rates used, the costs that will be incurred and the timing of when these costs will occur. In addition, in determining the provision it is assumed that the Company will utilize technology and materials that are currently available.

3. Share-based payments

Compensation costs pursuant to the share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

4. Deferred taxes

The calculation of the deferred tax asset or liability is based on assumptions about the timing of many taxable events and the enacted or substantively enacted rates anticipated to apply to income in the years in which temporary differences are expected to be realized or reversed.

5. Depreciation and amortization

Estimated useful lives of property, plant and equipment is based on management's judgments and assumptions about the physical useful lives of the assets and the economic life, which may be associated with the reserve life and commodity type of the production area, in addition to the estimated residual value and the method by which the asset depreciates.

Changes in Accounting Principles and Practices

Future Changes in IFRS Accounting Policies

The following standards and amendments from the International Accounting Standards Board ("IASB") have not been adopted by Pembina but may result in future changes to Pembina's accounting policies and disclosure. The Company is currently evaluating the impact that these standards will have on its results of operations and financial position.

IFRS 9 *Financial Instruments* – in November 2009 and revised in October 2010. This standard replaces the current multiple classification and measurement model for financial assets and liabilities with a proposed single model for only two classification categories: amortized cost and fair value. The standard is currently required to be adopted for periods beginning January 1, 2015.

IFRS 10 *Consolidated Financial Statements* – in May 2011, the IASB issued IFRS 10 which provides additional guidance to determine whether an entity should be included within the consolidated financial statements of Pembina. The guidance applies to all investees, including special purpose entities. The standard is required to be adopted for periods beginning January 1, 2013.

IFRS 11 *Joint Arrangements* – in May 2011, the IASB issued IFRS 11 which presents a new model for the financial reporting of joint arrangements. The new model determines whether an entity should account for joint arrangements using proportionate consolidation or the equity method with emphasis on the substance rather than legal form of a joint arrangement. The standard is required to be adopted for periods beginning January 1, 2013.

IFRS 12 *Disclosure of Interests in Other Entities* – in May 2011, the IASB issued IFRS 12 which provides guidance on the disclosure requirements for subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013.

IFRS 13 *Fair Value Measurement* – in May 2011, the IASB issued IFRS 13 to provide specific guidance for all standards where IFRS requires or permits fair value measurement. The standard defines fair value and provides guidance on disclosures about fair value measurements. The standard is required to be adopted for periods beginning January 1, 2013.

IAS 1 *Presentation of Items of Other Comprehensive Income* – in June 2011, the IASB issued amendments to IAS 1 Presentation of Financial Statements to separate items of other comprehensive income that may be subsequently reclassed to income. The standard is required to be adopted for periods beginning on or after July 1, 2012.

IAS19 *Employee Future Benefits* – in June 2011, the IASB issued amendments to IAS 19 Employee Future Benefits. The standard is to prescribe the accounting and disclosure for employee benefits and requires an entity to recognize a liability when an employee has provided service in exchange for employee benefits to be paid in the future; and an expense when the entity consumes the economic benefit arising from service provided by an employee in exchange for employee benefits. The standard is required to be adopted for periods beginning January 1, 2013.

IAS 27 *Separate Financial Statements* has been amended to conform to the changes made in IFRS 10 but includes guidance for preparation of non-consolidated parent company financial statements. The standard is required to be adopted for periods beginning January 1, 2013.

IAS 28 *Investments in Associates and Joint Ventures* has been amended to conform to the changes made in IFRS 10 and IFRS 11. The standard provides guidance on the accounting treatment for investments and equity accounted investees. The standard is required to be adopted for periods beginning January 1, 2013.

IAS 32 *Financial Instruments: Presentation* has been amended to provide guidance on the offsetting of financial assets and financial liabilities. The standard is required to be adopted for periods beginning January 1, 2014.

Future Tax Changes

On December 15, 2011, the 2011 Federal Budget Notice of Ways and Means motion, which was tabled as a bill to implement new rules for corporations that carry on business in partnerships, received Royal Ascent. The change could result in an increase in Canadian taxes paid by Pembina over the next five years.

Under Canadian tax law, partners in a partnership report their shares of the partnership's income or loss each year. When the partnership uses a different tax year than the partner, the partner generally takes into account the income or loss allocated by the partnership in the year that ends within the partner's tax year. Under the bill, certain partners would be required to accrue their share of the partnership's income through the end of the partners' tax years (even if the partnership's year has not yet ended). Changes to this system can result in the partner being required to report more than one year of the partnership's income for a single tax year.

Certain of Pembina's subsidiaries are partners in partnerships and will be required to report additional income and pay additional Canadian income taxes. Although Pembina would be allowed to spread the accelerated income over a prospective five year period, the amount of Canadian income taxes paid by Pembina could increase and accelerate our expected taxable horizon. The Company is currently evaluating the available options with respect to this matter and the subsequent impact to Pembina's tax position and horizon, which is still estimated to be during 2014.

Common Share Information[(1)]

($ thousands, except where noted)	**Feb. 14, 2012**[(2)]	Dec. 31, 2011	Dec. 31, 2010
Trading volume and value			
Total volume *(shares)*	**39,424,787**	75,574,785	91,431,769
Average daily volume *(shares)*	**1,271,767**	325,753	365,727
Value traded	**1,079,695**	1,947,702	1,755,005
Shares outstanding *(shares)*	**167,936,271**	167,908,271	166,876,651
Closing share price *(dollars)*	**28.47**	29.66	21.60
Market value			
Shares	**4,781,138**	4,980,151	3,604,543
5.75% convertible debentures	**329,009**[(3)]	326,760[(4)]	303,750[(5)]
Market capitalization	**5,110,146**	5,306,911	3,908,293
Senior debt	**1,417,380**	1,338,116	1,022,958
Total enterprise value[(6)]	**6,527,526**	6,645,027	4,931,251

(1) On October 1, 2010 all trust units and convertible debentures of the Fund outstanding were converted to common shares and convertible debentures of Pembina Pipeline Corporation pursuant to the Conversion of the Fund to a corporate structure. Trading information in this table reflects activity on the TSX.
(2) Based on 31 trading days from January 3, 2012 to February 14, 2012 inclusive.
(3) $299.8 million principal amount of 5.75 percent convertible debentures outstanding at a market price of $109.75 at February 14, 2012 and with a conversion price of $28.55.
(4) $299.8 million principal amount of 5.75 percent convertible debentures outstanding at a market price of $109 at December 31, 2011.
(5) $300 million principal amount of 5.75 percent convertible debentures outstanding at a market price of $101.25 at December 31, 2010.
(6) Refer to "Non-GAAP Measures" on page 33.

Pembina's shares, along with the 5.75 percent convertible debentures, are publicly traded on the Toronto Stock Exchange. The total market value of Pembina's outstanding securities was $6.6 billion at December 31, 2011. Issued and outstanding shares of Pembina rose to 167.9 million by the end of 2011, compared to 166.9 million in 2010. During 2011, 7,704 shares were issued through the conversion of the 5.75 percent convertible debentures and approximately 1 million shares were issued upon the exercise of options by non-officer employees of Pembina.

Subsequent to year-end, Pembina has reinstated the DRIP. As of January 25, 2012 and for the dividend payable on February 15, 2012, eligible Pembina shareholders have the opportunity to receive, by reinvesting the cash dividends declared payable by Pembina on their shares, either: (i) additional common shares at a discounted subscription price equal to 95 percent of the Average Market Price (as defined in the DRIP), pursuant to the "Dividend Reinvestment Component" of the DRIP, or (ii) premium cash payment (the "Premium Dividend™") equal to 102 percent of the amount of reinvested dividends, pursuant to the "Premium Dividend™ Component" of the DRIP. Additional information about the terms and conditions of the DRIP can be found at www.pembina.com.

Risk Factors

Pembina's value proposition is based on maintaining a very low risk profile. In addition to contractually eliminating the majority of its business risk, Pembina has formal risk management policies, procedures and systems designed to mitigate any residual risks, such as market price risk, credit risk and operational risk. Certain of the risks associated with Pembina's business are discussed below, and for a full discussion of these and other risk factors affecting the business and operation of Pembina and its operating subsidiaries, readers are referred to Pembina's Annual Information Form, an electronic copy of which is available at www.pembina.com or on Pembina's SEDAR profile at www.sedar.com. Shareholders and prospective investors should carefully consider these risk factors before investing in Pembina's securities, as each of these risks may negatively affect the trading price of Pembina's securities, the amount of dividends paid to shareholders and the ability of Pembina to fund its debt obligations, including debt obligations under its outstanding convertible debentures and any other debt securities that Pembina may issue from time to time.

MARKET RISKS

Credit Risk

Pembina is subject to credit risk arising out of its operations. A majority of Pembina's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risk. Credit risk is managed through credit approval and monitoring procedures. The credit worthiness assessment takes into account available qualitative and quantitative information about the counterparty, including, but not limited to, financial status and external credit ratings. Depending on the outcome of each assessment, guarantees or some other credit enhancement may be requested as security. Pembina attempts to mitigate its exposure by entering into contracts with customers that may permit netting or entitle Pembina to lien or take product in-kind and/or allow for termination of the contract on the occurrence of certain events of default. Each business segment monitors outstanding accounts receivable on an ongoing basis.

Debt Service

At the end of 2011, Pembina had exposure to floating interest rates on $114.9 million in debt. A one percent change in short-term interest rates would have an annualized impact of $1.1 million on net cash flows. Variations in interest rates and scheduled principal repayments, if required under the terms of the banking agreements could result in significant changes in the amounts required to be applied to debt service before payment of any dividends to Pembina's shareholders. Certain covenants in the agreements with the lenders may also limit payments by Pembina's operating subsidiaries. Although Pembina believes that the existing credit facilities are sufficient, there can be no assurance that the amount will be adequate for Pembina's financial obligations or that additional funds can be obtained. Holders of senior secured notes, with a balance of $58 million at December 31, 2011, have been provided with security over substantially all of the assets of the Company. If Pembina becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, the lenders will rank senior to Pembina's shareholders and outstanding convertible debentures. As a result, dividends from Pembina to shareholders and the market value of Pembina's securities would be adversely affected by such circumstances.

Capital Resources

The timing and amount of Pembina's capital expenditures, and the ability of Pembina to repay or refinance existing debt as it becomes due, directly affects the amount of cash dividends that Pembina pays to shareholders. Future acquisitions, expansions of Pembina's pipeline systems and midstream operations, other capital expenditures, including the capital expenditures that Pembina has committed to in respect of the Resthaven Facility, the Saturn Facility and the expansion of the Northern NGL System and the repayment or refinancing of existing debt as it becomes due will be financed from sources such as cash generated from operations, the issuance of additional shares or other securities (including debt securities) of Pembina, and borrowings. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made. There can be no assurance that sufficient capital will be available on terms acceptable to Pembina, or at all, to make additional investments, fund future expansions or make other required capital expenditures. To the extent that external sources of capital, including the issuance of additional shares or other securities or the availability of additional credit facilities, become limited or unavailable on favourable terms or at all due to credit market conditions or otherwise, the ability of Pembina to make the necessary capital investments to maintain or expand its operations, to repay outstanding debt and to invest in assets, as the case may be, may be impaired. To the extent Pembina is required to use cash flow to finance capital expenditures or acquisitions or to repay existing debt as it becomes due, the level of dividends to shareholders of Pembina may be reduced.

GENERAL BUSINESS RISKS

Execution Risk

Pembina's ability to successfully execute the development of its growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, shortages and in-service delays. Pembina's growth plans may strain its resources and may be subject to high cost pressures in the North American energy sector. Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation, and environmental and regulatory permitting. Cost escalations may impact project economics. Construction delays due to slow delivery of materials, contractor non-performance, weather conditions and shortages may impact project development. Labour shortages and productivity issues may also affect the successful completion of the projects. Pembina has a centralized and clearly defined governance structure and process for all major projects with dedicated resources organized to lead and execute each major project. Capital constraints and cost escalation risks are mitigated through structuring of commercial agreements, typically where shippers retain complete or a share of capital cost excess. Pembina's emphasis on corporate social responsibility promotes generally positive relationships with landowners, aboriginal groups and governments, which help to facilitate right-of-way acquisition, permitting and scheduling. Detailed cost tracking and centralized purchasing is used on all major projects to facilitate optimum pricing and service terms. Strategic relationships have been developed with suppliers and contractors. Compensation programs, communications and the working environment are aligned to attract, develop and retain qualified personnel.

Operational Risks

Operating risks include: pipeline leaks, the breakdown or failure of equipment, information systems or processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); spills at truck terminals and hubs; failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs; and, other similar events, many of which are beyond the control of Pembina. The occurrence or continuance of any of these events could increase the cost of operating Pembina's assets or reduce revenues, thereby impacting earnings. Pembina is committed to preserving customer and shareholder value by proactively managing operational risk through safe and reliable operations. Senior managers are responsible for the daily supervision of operational risk by ensuring appropriate policies and procedures are in place within their business units and internal controls are operating efficiently. Pembina also has an extensive program to manage system integrity, which includes the development and use of in-line inspection tools and various other leak detection technologies. Maintenance, excavation and repair programs are directed to the areas of greatest benefit, and pipe is replaced or repaired as required. Pembina also maintains comprehensive insurance coverage for significant pipeline leaks and has a comprehensive security program designed to reduce security-related risks. While Pembina feels the level of insurance is adequate, it may not be sufficient to cover all potential losses.

Reserve Replacement & Throughput

Pembina's conventional pipeline tariff revenues are based on a variety of tolling arrangements, including "ship or pay" contracts, cost of service arrangements and market-based tolls. As a result, certain pipeline tariff revenues are heavily dependent on throughput levels of crude oil, NGL and condensate. Future throughput on Pembina's crude oil and NGL pipelines and replacement of oil and gas reserves in the service areas will depend on the success of producers operating in those areas in exploiting their existing reserve bases and exploring for and developing additional reserves. Without reserve additions, or expansion of the service areas, throughput on such pipelines will decline over time as reserves are depleted. As oil and gas reserves are depleted, production costs may increase relative to the value of the remaining reserves in place, causing producers to shut in production and seek lower-cost alternatives for transportation. If the level of tariff revenue collected by Pembina decreases as a result, cash flow available to pay cash dividends to shareholders and to service obligations under the convertible debentures could be adversely affected. Over the long-term, Pembina's business will depend, in part, on the level of demand for crude oil, condensate, NGL and natural gas in the markets served by Pembina's crude oil and NGL pipelines. The global economic events of 2008 and 2009 had a substantial downward effect on the demand for and prices of such products. Although prices rebounded in 2010 and remained strong through 2011, Pembina cannot predict the impact of future economic conditions on the energy and petrochemical industries or future demand for and prices of natural gas, crude oil, condensate and NGL. Future prices of these products are determined by supply and demand factors, including weather and general economic conditions as well as political and other conditions in other oil and natural gas regions, all of which are beyond Pembina's control.

Terminals, Storage And Hub Services

The value potential associated with terminal, storage and hub services is dependent upon the ability of Pembina to: provide connections to both downstream pipelines and end-use markets; understand the value of the commodities transported and terminalled; provide flexibility and a variety of storage options; and a liquid, responsive, forward commodity market. Part of the value of various grades of crude oil is their respective differentials. These differentials are based primarily on the refinery yields, local supply-demand dynamics and liquidity. Pembina actively monitors market conditions and stream values to target revenue opportunities.

Environmental Costs & Liabilities

Pembina's operations, facilities and petroleum product shipments are subject to extensive national, regional and local environmental, health and safety laws and regulations governing, among other things, discharges to air, land and water, the handling and storage of petroleum compounds and hazardous materials, waste disposal, the protection of employee health, safety and the environment, and the investigation and remediation of contamination. Pembina's facilities could experience incidents, malfunctions or other unplanned events that cause spills or emissions in excess of permitted levels and result in personal injury, fines, penalties or other sanctions and property damage. Pembina could also incur liability in the future for environmental contamination associated with past and present activities and properties. Pembina's facilities and pipelines must maintain a number of environmental and other permits from various governmental authorities in order to operate, and these facilities are subject to inspection from time to time. Failure to comply with these requirements could result in operational interruptions, fines or penalties, or the need to install potentially costly pollution control technology. While Pembina believes its current operations comply with all applicable environmental and safety regulations, there can be no assurance that substantial costs or liabilities will not be incurred. Moreover, it is possible other developments, such as increasingly strict environmental and safety laws, regulation and enforcement or claims for damages to persons or property resulting from Pembina's operations, could result in significant costs and liabilities to Pembina. If Pembina were not able to recover the resulting costs through insurance or revenue, cash flow available to pay dividends to shareholders or to service obligations under its convertible debentures could be adversely affected. While Pembina maintains insurance to cover damage caused by seepage or pollution in an amount it considers prudent and in accordance with industry standards, certain provisions of this insurance may limit its availability in respect of certain occurrences unless they are discovered within fixed timed periods. These periods can range from 72 hours to 30 days. If Pembina is unaware of or is unable to locate a spill within the relevant time period, insurance coverage may not be available. However, Pembina believes it has adequate leak detection systems in place to detect and monitor a significant spill. Pembina is committed to protecting the health and safety of employees, contractors and the general public, and to sound environmental stewardship.

Pembina believes that prevention of incidents and injuries and protection of the environment benefits everyone and delivers increased value to shareholders, customers and employees. Pembina has health, safety and environmental management systems and established policies, programs and practices for conducting safe and environmentally sound operations. Pembina conducts regular reviews and audits to assess compliance with legislation and company policy.

Reputation

Reputation risk is the potential for negative impacts that could result from the deterioration of Pembina's reputation with key stakeholders. The potential for harming Pembina's corporate reputation exists in every business decision, and all risks can have an impact on reputation, which in turn can negatively impact Pembina's business and its securities. Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, liquidity, and regulatory and legal risks must all be managed effectively to safeguard Pembina's reputation. Negative impacts from a compromised reputation could include revenue loss, reduction in customer base, and decreased value of Pembina's securities. Pembina's reputation as a reliable and responsible energy services provider with consistent financial performance and long-term financial stability is one of its most valuable assets. Key to effectively building and maintaining Pembina's reputation is fostering a culture that promotes integrity and ethical conduct. Ultimate responsibility for Pembina's reputation lies with the executive team, who examines reputational risk and issues as part of all business decisions. Nonetheless, every employee and representative of Pembina has a responsibility to contribute in a positive way to its reputation. This means ensuring ethical practices are followed at all times, interactions with our stakeholders are positive, and compliance with applicable policies, legislation and regulations. Reputational risk is most effectively managed when every individual works continuously to protect and enhance Pembina's reputation.

Competition

Pembina competes with other pipelines in its service areas, other transporters of crude oil and NGL, and other midstream and gas services businesses. The introduction of competing transportation alternatives into Pembina's service areas could potentially limit Pembina's ability to adjust tolls as it may deem necessary. Additionally, potential pricing differentials on the components of NGL may result in these components being transported by competing gas pipelines. Pembina believes it is prepared for and determined to meet these existing and potential competitive pressures.

Regulation

Legislation in Alberta and British Columbia exists to ensure producers have fair and reasonable opportunities to produce, transport, process and market their reserves. The Alberta Energy Resources Conservation Board and the British Columbia Utilities Commission may, upon application or following a hearing (and in Alberta with the approval of the Lieutenant Governor in council), declare the operator of a pipeline a common carrier of oil or NGL and must not discriminate between producers who seek access to the pipeline. Producers and shippers may also apply to the regulatory authorities for a review of tariffs if they believe the tariffs are not just and reasonable. Applications by producers to have a pipeline operator declared a common carrier are usually accompanied with an application to have tariffs set by the regulatory authorities. The extent to which regulatory authorities in such instances can override existing transportation or processing contracts has not been fully decided. The potential for direct regulation of tolls, other than for the provincially regulated B.C. Pipelines, while considered remote, could result in toll levels that are not considered fair and reasonable by Pembina and could impair the economic operation of such regulated pipeline systems.

Pipeline Abandonment Costs

Pembina is responsible for complying with all applicable laws and regulations regarding the abandonment of its pipeline assets at the end of their economic life, and such abandonment costs may be substantial. The proceeds of the disposition of certain assets associated with Pembina's pipeline systems, including, in respect of certain pipeline systems, linefill would be available to offset abandonment costs. It is not possible to definitively predict abandonment costs since they will be a function of regulatory requirements at the time, and the value of Pembina's assets, including linefill, may be more or less than the abandonment costs. Pembina may, in the future, determine it prudent or be required by applicable laws or regulations to establish and fund one or more reclamation funds to pay for future abandonment costs. Such reserves could decrease cash flow available for dividends to shareholders and to service obligations under Pembina's outstanding convertible debentures. On May 26, 2009, the National Energy Board ("NEB") issued its Reasons for Decision RH-2-2008 with respect to the Land Matters Consultation Initiative – Stream 3, which dealt with financial issues of pipeline abandonment for pipelines under the NEB's jurisdiction. The NEB decided in principle to set an ultimate goal of having all companies under its jurisdiction begin setting aside funds for the abandonment of pipelines no later than five years from the date of the decision. Pembina submitted preliminary cost estimates to the NEB for its affected segments of pipeline on November 30, 2011 and is working towards a pipeline abandonment fund collection plan to present to the NEB prior to the setting aside of funds. Pembina has approximately 200 km of pipeline under the NEB's jurisdiction.

Structural Integrity Of The Storage Facility

The operation of the Storage Facility is subject to risks related to the nature of the salt caverns that are currently used to store ethylene. Three of the five ethylene storage caverns in the Storage Facility are currently out of service, with no material impact to Pembina in 2011, and it is unlikely that they will be put back into ethylene storage service. The joint owners of this facility are investigating other potential uses for these caverns as well as examining alternative capacity options for ethylene storage available elsewhere on the jointly owned property. If arrangements with respect to alternative uses and additional ethylene storage capacity are not entered into on terms favourable to Pembina, or if other disruptions to the operations of the caverns occur and reduce the storage capacity of the Storage Facility for an extended period of time, this would result in a reduction in the revenue received by Pembina from its ownership interest in the Storage Facility and could potentially decrease cash flow available for dividends to shareholders and to service obligations under the convertible debentures and Pembina's other debt obligations. In addition, the Storage Limited Partnership may be required to make capital expenditures to ameliorate any such storage disruptions in excess of the obligations of Dow Canada and NOVA Chemicals to contribute to capital expenses under the Storage Agreement which could also result in a reduction in the revenue received by Pembina from its ownership interest in the Storage Facility.

Completion of the Resthaven and Saturn Facilities

The Resthaven Facility and the Saturn Facility are currently under development by Pembina and the successful completion of these facilities is dependent on numerous factors outside of Pembina's control. These factors include completion of the construction of the Resthaven Facility and Saturn Facility on schedule, as well as construction and labour costs that may change depending on supply, demand and/or inflation. Under the agreements governing the construction and operation of the Resthaven Facility and the Saturn Facility, Pembina is obligated to construct the facilities and Pembina bears the risk for its share of any cost overruns. While Pembina is not currently aware of any significant cost overruns at the date hereof, any such cost overruns in the future could reduce Pembina's expected return on the Resthaven Facility and the Saturn Facility and adversely affect Pembina's results of operations which, in turn, could reduce the level of cash available for dividends to shareholders. The construction of the Resthaven Facility and the Saturn Facility is subject to regulatory and environmental approval. There is no certainty, nor can Pembina provide any assurance, that regulatory and environmental approval will be received on a timely basis or at all.

Expansion of the Northern NGL System

Pembina has announced plans to expand throughput capacity on the Northern NGL System by 55,000 bpd. The successful completion of this expansion is dependent on numerous factors outside of Pembina's control. These factors include receipt of regulatory approval and reaching long-term commercial arrangements with customers in respect of the expansion, completion of the construction of the expansion on schedule, as well as construction and labour costs that may change depending on supply, demand and/or inflation. Any agreements with customers entered into with respect to the expansion may require that Pembina bears the risk for any cost overruns and any such cost overruns could reduce Pembina's expected return on the expansion and adversely affect Pembina's results of operations which, in turn, could reduce the level of cash available for dividends to shareholders. There is no certainty, nor can Pembina provide any assurance, that regulatory approval will be received or that satisfactory commercial arrangements with customers will be reached on a timely basis or at all.

Expansion of the Cutbank Complex

Pembina has completed construction of the Musreau Deep Cut Facility and is near completion with start-up on February 15, 2012. Pembina has contracted approximately 80 percent of the planned capacity at the facility. Although Pembina expects to contract the remaining capacity under terms designed to provide Pembina with cash flow certainty, there can be no assurance that Pembina will be able to enter into such contracts on favourable terms and on a timely basis, or at all. Any failure to enter into such contracts could reduce Pembina's expected return on the facility and adversely affect Pembina's results of operations which, in turn, could reduce the level of cash available for dividends to shareholders.

Pembina has also announced plans to expand shallow cut gas processing capability at the Musreau Gas Plant. The successful completion of this expansion is dependent on numerous factors outside of Pembina's control. These factors include receipt of regulatory and environmental approval, completion of the construction of the expansion on schedule, as well as construction and labour costs that may change depending on supply, demand and/or inflation. Pembina must bear the risk for any cost overruns. Any such cost overruns could reduce Pembina's expected return on the expansion and adversely affect Pembina's results of operations which, in turn, could reduce the level of cash available for dividends to shareholders. There is no certainty, nor can Pembina provide any assurance, that regulatory and environmental approval will be received on a timely basis or at all.

RISKS RELATED TO THE ARRANGEMENT

Termination of the Arrangement Agreement

The Arrangement Agreement may be terminated by Pembina or Provident in certain circumstances. Accordingly, there is no certainty, nor can Pembina provide any assurance, that the Arrangement Agreement will not be terminated by either Pembina or Provident before the completion of the Arrangement. Failure to complete the Arrangement could materially negatively impact the price of the common shares of Pembina.

Conditions Precedent and Requirement for Regulatory, Shareholder and Court Approvals

There can be no certainty that all conditions precedent to the Arrangement will be satisfied or waived, nor can there be any certainty of the timing of their satisfaction or waiver. The completion of the Arrangement is subject to a number of conditions precedent, some of which are outside of the control of Pembina and Provident, including the approval of the shareholders of Pembina and the shareholders of Provident, receipt of regulatory approvals, including competition approval, and receipt of approval from the Court. There is no certainty, nor can Pembina provide any assurance, that these conditions will be satisfied. If for any reason the Arrangement is not completed, the market price of the common shares of Pembina may be adversely affected. In addition, the requirement to take certain actions or to agree to certain conditions to satisfy the conditions precedent to the Arrangement or to obtain any required regulatory approvals may have a material adverse effect on the business and affairs of Pembina or the trading price of the common shares of Pembina, after completion of the Arrangement.

Failure to Realize the Anticipated Benefits of the Arrangement

Pembina has entered into the Arrangement Agreement to realize certain benefits. Achieving the benefits of the Arrangement depends in part on the ability of the combined entity to effectively capitalize on its scale, scope and leadership position in the energy infrastructure industry, to realize the anticipated capital and operating synergies, to profitably sequence the growth prospects of its asset base and to maximize the potential of its improved growth opportunities and capital funding opportunities as a result of combining the businesses and operations of Pembina and Provident. A variety of factors may adversely affect the ability to achieve the anticipated benefits of the Arrangement.

Risks Related to the Integration of Pembina's and Provident's Businesses

The ability to realize the benefits of the Arrangement will depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as on Pembina's ability to realize the anticipated growth opportunities and synergies from integrating its business with that of Provident following completion of the Arrangement. This integration will require the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities following completion of the Arrangement, and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the ability of Pembina to achieve the anticipated benefits of the Arrangement.

Selected Quarterly Financial Information

	2011				2010				2009(1)
($ millions, except where noted)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Revenue	**468.0**	**302.9**	**511.5**	**394.3**	290.2	266.6	386.4	289.0	256.4
Operations	**55.1**	**55.9**	**37.8**	**43.2**	42.3	40.0	37.2	36.4	39.7
Product purchases	**308.2**	**146.6**	**363.4**	**253.7**	161.7	148.4	261.9	163.1	127.2
Operating margin	**104.7**	**100.4**	**110.3**	**97.4**	86.2	78.2	87.3	89.5	89.5
Depreciation and amortization Included in operations	**19.5**	**17.8**	**15.8**	**14.9**	15.6	15.3	15.3	15.5	11.2
Gross profit	**85.2**	**82.6**	**94.5**	**82.5**	70.6	62.9	72.0	74.0	78.3
EBITDA	**87.0**	**86.8**	**103.1**	**87.2**	79.1	68.1	78.0	85.6	72.5
Cash flow from operating activities	**74.3**	**88.0**	**50.4**	**74.5**	54.6	66.6	69.6	66.5	72.0
Cash flow from operating activities per common share *($ per share)*	**0.44**	**0.53**	**0.30**	**0.45**	0.33	0.41	0.43	0.41	0.46
Adjusted cash flow from operating activities(2)	**66.8**	**76.0**	**86.8**	**68.0**	64.9	54.0	63.8	70.0	57.5
Adjusted cash flow from operating activities per common share(2) *($ per share)*	**0.40**	**0.45**	**0.52**	**0.41**	0.39	0.33	0.39	0.43	0.37
Earnings for the period	**45.1**	**30.1**	**48.0**	**42.5**	55.2	28.6	37.7	52.2	52.9
Earnings per common share *($ per share)*:									
Basic	**0.27**	**0.18**	**0.29**	**0.25**	0.34	0.19	0.23	0.32	0.34
Diluted	**0.27**	**0.18**	**0.29**	**0.25**	0.33	0.19	0.23	0.32	0.33
Common shares outstanding *(millions)*:									
Weighted average (basic)	**167.4**	**167.6**	**167.3**	**167.0**	165.0	164.0	163.2	161.8	157.5
Weighted average (diluted)	**168.2**	**168.2**	**168.0**	**167.6**	171.7	166.9	166.2	165.2	160.9
End of period	**167.9**	**167.7**	**167.5**	**167.1**	166.9	164.5	163.6	162.2	158.6
Dividends	**65.4**	**65.4**	**65.3**	**65.1**	64.6	64.0	63.8	62.8	61.4
Dividends per common share *($ per share)*:									
Basic	**0.3900**	**0.3900**	**0.3900**	**0.3900**	0.3900	0.3900	0.3900	0.3900	0.3900
Diluted	**0.3883**	**0.3853**	**0.3850**	**0.3849**	0.3859	0.3858	0.3861	0.3832	0.3848

(1) As Pembina's IFRS transition date was January 1, 2010, 2009 comparative information has not been restated and is presented in accordance with previous Canadian GAAP.

(2) Refer to Non-GAAP measures on page 33.

Selected Quarterly Operating Information

	2011				2010				2009
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Average throughput *(thousands of bpd)*									
Total Conventional Throughput	**422.8**	**430.4**	**411.4**	**390.3**	375.0	361.4	370.4	389.3	379.4
Oil Sands & Heavy Oil[(1)]	**870.0**	**775.0**	**775.0**	**775.0**	775.0	775.0	775.0	775.0	775.0
Total average throughput	**1,292.8**	**1,205.4**	**1,186.4**	**1,165.3**	1,150.0	1,136.4	1,145.4	1,164.3	1,154.4
Average daily Cutbank Complex (MMcf/d net to Pembina)	**263.9**	**247.6**	**237.6**	**228.3**	227.8	215.8	221.6	216.9	197.4
BOE *(thousands)*	**1,336.8**	**1,246.7**	**1,226.0**	**1,203.4**	1,188.0	1,172.4	1,182.3	1,200.5	1,187.3

(1) Oil Sands & Heavy Oil throughput refers to contracted capacity.

Additional Information

Additional information relating to Pembina, including its Annual Information Form, Management Information Circular and financial statements can be found at www.pembina.com or at www.sedar.com.

Non-GAAP Measures

Throughout this MD&A, Pembina has used the following terms that are not defined by GAAP but are used by management to evaluate performance of Pembina and its business. Since certain Non-GAAP financial measures may not have a standardized meaning, securities regulations require that Non-GAAP financial measures are clearly defined, qualified and reconciled to their nearest GAAP measure.

Earnings before interest, taxes, depreciation and amortization ("EBITDA")

EBITDA is commonly used by management, investors and creditors in the calculation of ratios for assessing leverage and financial performance and is calculated as results from operating activities plus share of profit from equity accounted investees (before tax) plus depreciation and amortization (included in operations and general and administrative expense).

	3 Months Ended		**Year Ended**	
($ millions)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Results from operating activities	**63.3**	58.8	**281.1**	230.2
Add:				
Share of profit from equity accounted investees (before tax, depreciation and amortization)	**3.2**	4.5	**12.9**	17.3
Depreciation and amortization	**20.5**	15.8	**70.3**	63.3
EBITDA	**87.0**	79.1	**364.3**	310.8

Adjusted earnings

Adjusted earnings is commonly used by management for assessing and comparing financial performance each reporting period and is calculated as earnings before tax excluding hedging activities plus share of profit from equity accounted investees (before tax).

	3 Months Ended		Year Ended	
($ millions)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Earnings before income tax and equity accounted investees	**43.3**	48.9	**198.8**	158.4
Add (deduct):				
Change in fair value of derivatives	**(1.5)**	(7.2)	**2.4**	3.3
Share of profit of investments in equity accounted investees (after tax)	**1.5**	2.6	**5.8**	9.1
Tax on share of profit of investments in equity accounted investees	**0.5**	0.5	**1.9**	2.7
Adjusted earnings	**43.8**	44.8	**208.9**	173.5
Adjusted earnings per common share	**0.2609**	0.2714	**1.2478**	1.0630

Adjusted cash flow from operating activities

Adjusted cash flow from operating activities is commonly used by management for assessing financial performance each reporting period and is calculated as cash flow from operating activities plus employee future benefit contributions, change in non-cash working capital less employee future benefit expense, share-based payments, and an adjustment to accrual basis for interest and financing fees.

	3 Months Ended		Year Ended	
($ millions)	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010
Cash flow from operating activities	**74.3**	54.6	**287.1**	257.2
Add (deduct):				
Employee future benefit contributions	**2.0**	2.0	**8.0**	8.0
Change in non-cash working capital	**(17.0)**	8.0	**18.7**	9.1
Employer future benefits expense	**(1.2)**	(1.1)	**(4.8)**	(4.6)
Share-based payments	**(7.7)**	(0.7)	**(18.7)**	(14.9)
Adjustment to accrual basis for interest expense and financing fees	**6.8**	2.2	**6.4**	(2.1)
Change in provision	**9.6**		**0.8**	
Adjusted cash flow from operating activities	**66.8**	65.0	**297.5**	252.7
Adjusted cash flow from operating activities per common share	**0.3977**	0.3935	**1.7770**	1.5479

Operating margin

Operating margin is commonly used by management for assessing financial performance and is calculated as gross profit less operating expense and product purchases.

Reconciliation of operating margin to gross profit:

	Year Ended	
($ thousands)	**Dec. 31, 2011**	Dec. 31, 2010
Revenue	**1,676,710**	1,232,190
Cost of sales:		
Operations	**191,923**	155,818
Product purchases	**1,072,048**	735,223
Operating margin	**412,739**	341,149
Depreciation and amortization included in operations	**68,012**	61,652
Gross profit	**344,727**	279,497

Total enterprise value

Total enterprise value, in combination with other measures, is used by management and the investment community to assess the overall market value of the business. Total enterprise value is calculated based on the market value of common shares and convertible debentures at a specific date plus senior debt.

Management believes these supplemental Non-GAAP measures facilitate the understanding of Pembina's results from operations, leverage, liquidity and financial positions. Investors should be cautioned that EBITDA, adjusted earnings, adjusted cash flow from operating activities, operating margin and total enterprise value should not be construed as alternatives to net earnings, cash flow from operating activities or other measures of financial results determined in accordance with GAAP as an indicator of Pembina's performance. Furthermore, these Non-GAAP measures may not be comparable to similar measures presented by other issuers.

Forward-Looking Statements & Information

Certain statements contained in this MD&A constitute "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements").

All forward-looking statements are based on Pembina's current expectations, estimates, projections, beliefs and assumptions based on information available at the time the statement was made and in light of its experience and its perception of historical trends. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "plan", "intend", "design", "target", "undertake", "view", "indicate", "maintain", "explore", "entail", "schedule", "objective", "strategy", "likely", "potential", "envision", "aim" and similar expressions are intended to identify forward-looking statements.

By their nature, such forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Pembina believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of the MD&A.

In particular, this MD&A contains forward-looking statements, including certain financial outlook, pertaining to the following:

- the future levels of cash dividends that Pembina intends to pay to its shareholders, including Pembina's projections regarding an increase in the level of cash dividends pending successful closing of the Arrangement with Provident;
- the estimated future operating margin or EBITDA, as applicable, contributions from the proposed expansions at the Cutbank Complex's Musreau Gas Plant and the development of the proposed Resthaven Facility, the proposed Saturn Facility and the proposed Northern NGL System expansion, once such projects are completed;
- capital expenditure estimates, plans, schedules, rights and activities and the planning, development, construction, operations and costs of pipelines, gas service facilities, terminalling, storage and hub facilities and other facilities or energy infrastructure, including, but not limited to, in relation to the Pembina Nexus Terminal, the expansions at the Cutbank Complex's Musreau Gas Plant, the proposed Resthaven Facility and the proposed Saturn Facility, the proposed expansion plans to strengthen Pembina's transportation service options that it provides to producers developing the Cardium oil formation located in Central Alberta, the expansion of throughput capacity on the Northern NGL System and the proposed expansion of a number of existing truck terminals and construction of new full service terminals;
- future expansion of Pembina's pipelines and other infrastructure, including in respect of its Horizon Pipeline and the Nipisi and Mitsue Pipeline projects;
- pipeline, processing and storage facility and system operations and throughput levels;
- oil and gas industry exploration and development activity levels;
- Pembina's strategy and the development of new business initiatives;
- expectations regarding Pembina's ability to raise capital and to carry out acquisition, expansion and growth plans;
- treatment under governmental regulatory regimes including environmental regulations and related abandonment and reclamation obligations;
- future G&A expenses at Pembina;
- increased throughput potential due to increased activity and new connections and other initiatives on Pembina's pipelines;
- future cash flows, potential revenue and cash flow enhancements across Pembina's businesses and the maintenance of operating margins;
- tolls and tariffs and transportation, storage and services commitments and contracts;
- cash dividends and the tax treatment thereof;
- operating risks (including the amount of future liabilities related to pipeline spills and other environmental incidents) and related insurance coverage and inspection and integrity systems;
- the expected impact of Pembina's investments in the Drayton Valley and Edson, Alberta areas on producers in the area;
- expectations regarding contracts to be entered into with respect to the Musreau Deep Cut Facility;
- the expected capacity of the proposed Resthaven Facility and the proposed Saturn Facility;
- expectations regarding in-service dates for new developments, including the Resthaven Facility, the Saturn Facility and the Northern NGL System;
- expectations regarding additional capacity and tie-in opportunities on the new line segment near Edson, Alberta;
- expected contributions to and expenses of pension plans and expected long-term returns of pension plan assets;
- the possibility of renegotiating debt terms, repayment of existing debt, seeking new borrowing and/or issuing equity;
- the Arrangement, including the timing and business of the special meetings of shareholders of Pembina and Provident; the expected closing date of the Arrangement, the consideration to be paid under the Arrangement, the obligations of Pembina in connection with the Arrangement, expectations regarding the repurchase of debentures of Provident, the anticipated benefits of the Arrangement, the listing of Pembina shares following the Arrangement, the tax consequences of the Arrangement and the potential that Pembina's capital spending plan could be increased following closing of the Arrangement; and
- competitive conditions.

Various factors or assumptions are typically applied by Pembina in drawing conclusions or making the forecasts, projections, predictions or estimations set out in forward-looking statements based on information currently available to Pembina. These factors and assumptions include, but are not limited to:

- the success of Pembina's operations;
- prevailing commodity prices and exchange rates;
- the availability of capital to fund future capital requirements relating to existing assets and projects, including but not limited to future capital expenditures relating to expansion, upgrades and maintenance shutdowns;
- future operating costs;
- in respect of the estimated future EBITDA contribution from Pembina's Musreau Deep Cut Facility at the Cutbank Complex and its estimated in-service date of February 2012; that counterparties will comply with contracts in a timely manner; that there are no unforeseen events preventing the performance of contracts by Pembina; that there are no unforeseen construction costs related to the facility; and that there are no unforeseen material costs relating to the facility which are not recoverable from customers;
- in respect of the estimated future EBITDA contribution from Pembina's proposed Resthaven Facility and the proposed Saturn Facility and their estimated in-service dates of late 2013 and the fourth quarter of 2013, respectively; that all

required regulatory and environmental approvals can be obtained on the necessary terms in a timely manner, that counterparties will comply with contracts in a timely manner; that there are no unforeseen events preventing the performance of contracts or the completion of such facilities; that such facilities will be fully supported by long-term firm service agreements accounting for the entire designed throughput at such facilities at the time of such facilities' completion, that there are no unforeseen construction costs related to the facilities; and that there are no unforeseen material costs relating to the facilities which are not recoverable from customers;

- in respect of the expansion of NGL throughput capacity on the Northern NGL System and the estimated in-service dates with respect to the same; that Pembina will receive regulatory approval; that Pembina will reach satisfactory long-term arrangements with customers with respect to the Northern NGL System; that counterparties will comply with contracts in a timely manner; that there are no unforeseen events preventing the performance of contracts by Pembina; that there are no unforeseen construction costs related to the expansion; and that there are no unforeseen material costs relating to the pipelines that are not recoverable from customers;
- in respect of the stability of and any potential increases in Pembina's dividend including following completion of the Arrangement; prevailing commodity prices, margins and exchange rates; that Pembina's and Provident's future results of operations will be consistent with past performance and management expectations in relation thereto; the continued availability of capital at attractive prices to fund future capital requirements relating to existing assets and projects, including but not limited to future capital expenditures relating to expansion, upgrades and maintenance shutdowns; the success of growth projects; future operating costs; that counterparties to material agreements will continue to perform in a timely manner; that there are no unforeseen events preventing the performance of contracts; and that there are no unforeseen material construction or other costs related to current growth projects or current operations;
- in respect of other developments, expansions and capital expenditures planned, including the proposed expansion of a number of existing truck terminals and construction of new full service terminals, the proposed expansion of the Musreau Gas Plant's shallow cut gas processing capability and the proposed expansion plans to strengthen Pembina's transportation service options that it provides to producers developing the Cardium oil formation located in Central Alberta, that counterparties will comply with contracts in a timely manner; that there are no unforeseen events preventing the performance of contracts by Pembina; that there are no unforeseen construction costs; and that there are no unforeseen material costs relating to the developments, expansions and capital expenditures which are not recoverable from customers;
- the future exploration for and production of oil, NGLs and natural gas in the capture area around Pembina's conventional and midstream and marketing assets, including new production from the Cardium formation in western Alberta, the demand for gathering and processing of hydrocarbons, and the corresponding utilization of Pembina's assets;
- prevailing regulatory, tax and environmental laws and regulations;
- the receipt, in a timely manner, of regulatory, shareholder, Court and third party approvals in respect of the Arrangement;
- the satisfaction of conditions to closing of the Arrangement; and
- that the Arrangement Agreement will not be terminated prior to closing of the Arrangement.

The actual results of Pembina could differ materially from those anticipated in these forward-looking statements as a result of the material risk factors set forth below:

- the regulatory environment and decisions;
- the impact of competitive entities and pricing;
- labour and material shortages;
- reliance on key alliances and agreements;
- the strength and operations of the oil and natural gas production industry and related commodity prices;
- non-performance or default by counterparties to agreements which Pembina or one or more of its affiliates has entered into in respect of its business;
- actions by governmental or regulatory authorities including changes in tax laws and treatment, changes in royalty rates or increased environmental regulation;
- fluctuations in operating results;
- adverse general economic and market conditions in Canada, North America and elsewhere, including changes in interest rates, foreign currency exchange rates and commodity prices;
- termination of the Arrangement Agreement prior to the closing of the Arrangement;
- that one or more conditions precedent to completion of the Arrangement, including regulatory, shareholder and Court approval, will not be satisfied;
- the failure to realize the anticipated benefits of the Arrangement;
- the failure to integrate the businesses of Pembina and Provident following closing of the Arrangement; and
- the other factors discussed under "Risk Factors" in Pembina's Management's Discussion and Analysis for the year ended December 31, 2011 and in Pembina's current Annual Information Form available under Pembina's profile at www.sedar.com.

These factors should not be construed as exhaustive. Unless required by law, Pembina does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Any forward-looking statements contained herein are expressly qualified by this cautionary statement.

Management of Pembina approved the financial outlook contained herein as of the date of this document. The purpose of the financial outlook contained herein is to give the reader an indication of the potential effects that the proposed expansions at the Cutbank Complex's Musreau Gas Plant, the proposed Resthaven Facility, the proposed Saturn Facility and the proposed expansion of the Northern NGL System may have on Pembina's operating results, once completed.

Readers should be aware that the information contained in the financial outlook contained herein may not be appropriate for other purposes.

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MANAGEMENT'S RESPONSIBILITY

The Consolidated Financial Statements of Pembina Pipeline Corporation (the "Company") are the responsibility of Pembina's management. The financial statements have been prepared in accordance with Canadian generally accepted accounting principles, using management's best estimates and judgments, where appropriate.

Management is responsible for the reliability and integrity of the financial statements, the notes to the financial statements and other financial information contained in this report. In the preparation of these financial statements, estimates are sometimes necessary because a precise determination of certain assets and liabilities is dependent on future events. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls designed to provide reasonable assurance that assets are safeguarded and that accounting systems provide timely, accurate and reliable financial information.

The Board of Directors of Pembina Pipeline Corporation (the "Board") is responsible for ensuring management fulfils its responsibilities for financial reporting and internal control. The Board is assisted in exercising its responsibilities through the Audit Committee, which consists of four non-management directors. The Audit Committee meets periodically with management and the auditors to satisfy itself that management's responsibilities are properly discharged, to review the financial statements and to recommend approval of the financial statements to the Board.

KPMG LLP, the independent auditors, have audited the Company's financial statements in accordance with Canadian generally accepted auditing standards and their report follows. The independent auditors have full and unrestricted access to the Audit Committee to discuss their audit and their related findings.

Robert B. Michaleski
President and Chief Executive Officer
Pembina Pipeline Corporation

Peter D. Robertson
Vice President Finance and Chief Financial Officer
Pembina Pipeline Corporation

February 15, 2012

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Pembina Pipeline Corporation

We have audited the accompanying consolidated financial statements of Pembina Pipeline Corporation, which comprise the consolidated statement of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010 and the consolidated statements of comprehensive income, changes in equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Pembina Pipeline Corporation as at December 31, 2011, December 31, 2010 and January 1, 2010 and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
Calgary Alberta, Canada

February 15, 2012

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

($ thousands)	Note	December 31 2011	December 31 2010	January 1 2010
Assets				
Current assets				
Cash and cash equivalents	5		125,397	53,927
Trade and other receivables	6	148,267	105,474	83,244
Derivative financial instruments		4,643	5,199	1,334
Inventory	7	22,783	26,099	18,998
		175,693	262,169	157,503
Non-current assets				
Property, plant and equipment	8	2,745,982	2,159,097	1,965,683
Intangible assets	9	243,904	244,602	245,300
Employee benefits	25			1,979
Investments in equity accounted investees	10	161,002	190,739	196,330
Derivative financial instruments		1,807	241	
Other receivables	6	10,814		
		3,163,509	2,594,679	2,409,292
Total Assets		3,339,202	2,856,848	2,566,795
Liabilities and Shareholders' Equity				
Current liabilities				
Bank indebtedness	5	676		
Trade payables and accrued liabilities	12	166,646	99,023	58,239
Dividends payable		21,828	21,694	20,616
Loans and borrowings	13	323,927	10,055	159,324
Derivative financial instruments		4,725	6,384	2,153
Convertible debentures	13			36,640
		517,802	137,156	276,972
Non-current liabilities				
Loans and borrowings	13	1,012,061	1,010,102	976,082
Convertible debentures	13	289,365	288,635	
Derivative financial instruments		12,813	7,703	4,812
Employee benefits	25	16,951	6,012	5,321
Share-based payments		14,060	5,252	12,893
Deferred revenue		2,185		
Provisions	14	405,433	281,694	217,103
Deferred tax liabilities	11	106,915	69,686	75,839
		2,377,585	1,806,240	1,569,022
Equity				
Share capital	15	1,811,734	1,794,536	1,657,803
Deficit		(834,921)	(739,351)	(660,030)
Accumulated other comprehensive income		(15,196)	(4,577)	
		961,617	1,050,608	997,773
Total Liabilities and Shareholders' Equity		3,339,202	2,856,848	2,566,795

See accompanying notes to consolidated financial statements

On behalf of the Board of Pembina Pipeline Corporation:

Lorne B. Gordon
Director
Chairman of the Board

Thomas W. Buchanan
Director
Chairman of the Audit Committee

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

Year Ended December 31			
($ thousands)	**Note**	**2011**	2010
Revenues	16	1,676,710	1,232,190
Cost of sales	17	1,331,983	952,693
Gross profit		344,727	279,497
General and administrative	18	62,191	48,631
Other expense (income)		1,429	658
		63,620	49,289
Results from operating activities		281,107	230,208
Finance income	21	(5,787)	(542)
Finance costs	21	88,125	72,343
Net finance costs		82,338	71,801
Earnings before income tax and equity accounted investees		198,769	158,407
Share of profit of investments in equity accounted investees (net of tax)		(5,766)	(9,103)
Income tax expense (reduction)	11	38,869	(8,320)
Earnings for the year		165,666	175,830
Other comprehensive income (loss)			
Defined benefit plan actuarial gains (losses)		(14,159)	(6,103)
Income tax reduction	11	3,540	1,526
Other comprehensive income (loss) for the year	25	(10,619)	(4,577)
Total comprehensive income for the year		155,047	171,253
Earnings per share			
Basic earnings per share *(dollars)*	23	0.99	1.08
Diluted earnings per share *(dollars)*	23	0.99	1.07

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

Year Ended December 31 *($ thousands)*	**2011**	2010
Trust Units		
Balance, beginning of period		1,657,803
Exercise of trust unit options		31,091
Issue of trust units, debenture conversions		10,134
Issue of trust units, distribution reinvestment plan		55,898
Share issue costs		(104)
Exchange of trust units for common shares on conversion to Corporation		(1,754,822)
Balance, end of period		
Share Capital		
Balance, beginning of period	1,794,536	
Balance on conversion to Corporation		1,754,822
Change of stock options from cash settled to equity settled		8,927
Share-based payment transactions	16,721	5,310
Issue of common shares, debenture conversions	220	25,299
Other	257	178
Balance, end of period	1,811,734	1,794,536
Deficit		
Balance, beginning of period	(739,351)	(660,030)
Earnings for the period	165,666	175,830
Dividends declared	(261,236)	(255,151)
Balance, end of period	(834,921)	(739,351)
Other Comprehensive Income (Loss)		
Balance, beginning of period	(4,577)	
Defined benefit plan actuarial gains and losses, net of tax	(10,619)	(4,577)
Balance, end of period	(15,196)	(4,577)
Total Shareholders' Equity	961,617	1,050,608

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31

($ thousands)	Note	2011	2010
Cash provided by (used in):			
Operating activities:			
Earnings for the period		165,666	175,830
Adjustments for:			
Depreciation and amortization	19	70,219	63,274
Net finance costs	21	82,338	71,801
Share of profit of investments in equity accounted investees (net of tax)		(5,766)	(9,103)
Income tax expense (reduction)	11	38,869	(8,320)
Share-based payments	26	18,651	14,870
Employee future benefits expense	25	4,825	4,695
Decrease in provisions		(769)	
Other		(427)	1,689
Changes in non-cash working capital	24	(18,749)	(9,165)
Distributions from investments in equity accounted investees	10	16,869	17,328
Decommissioning liability expenditures	14	(3,123)	
Employer future benefit contributions	25	(8,000)	(8,000)
Payments received and deferred		2,185	
Realized gain on power derivative		4,413	
Interest paid		(80,529)	(58,246)
Interest received	21	414	542
Cash flow from operating activities		287,086	257,195
Financing activities:			
Bank borrowings		153,137	40,000
Repayment of senior secured notes		(7,981)	(7,423)
Debt repayment		(80,000)	(150,000)
Repayment of finance leases		(2,395)	(1,699)
Issuance of debt		250,000	
Issuance of convertible debentures			300,000
Repayment of convertible debentures		(220)	(1,207)
Financing fees		(1,774)	(11,756)
Share issue costs		(26)	(139)
Exercise of stock options		16,085	30,369
Issue of shares under Distribution Reinvestment Plan			55,898
Dividends to shareholders - current year		(239,408)	(233,457)
Dividends to shareholders - prior year		(21,694)	(20,617)
Cash flow from (used in) financing activities		65,724	(31)
Investing activities:			
Capital expenditures		(479,707)	(185,694)
Proceeds from sale of assets		824	
Cash flow used in investing activities		(478,883)	(185,694)
Change in cash		(126,073)	71,470
Cash, beginning of period		125,397	53,927
Cash (bank indebtedness), end of period		(676)	125,397

See accompanying notes to consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. REPORTING ENTITY

Pembina Pipeline Corporation ("Pembina" or the "Company") is an energy transportation and service provider domiciled in Canada. The consolidated financial statements ("Financial Statements") include the accounts of the Company, its wholly owned subsidiary companies, partnerships and any interests in associates and jointly controlled entities as at and for the year ending December 31, 2011. The Financial Statements present fairly the financial position, financial performance and cash flows of the Company.

On October 1, 2010 Pembina completed its conversion from an income trust to a corporation pursuant to a plan of arrangement (the "Arrangement") under the Alberta Business Corporations Act. Pursuant to the Arrangement, holders of trust units of Pembina Pipeline Income Fund (the "Fund") exchanged each trust unit held for a common share of Pembina Pipeline Corporation on a one-for-one basis.

The Financial Statements follow the continuity of interest basis of accounting whereby the Company is considered a continuation of the Fund. As a result, the consolidated comparative statement of financial position, statements of comprehensive income, statements of changes in shareholders' equity and cash flows include the Fund's results of operations for the period up to and including September 30, 2010 and the Company's results of operations thereafter. All references to shares and shareholders in the condensed consolidated financial statements and notes pertain to common shares and common shareholders subsequent to the conversion and trust unit and trust unit holders prior to the conversion.

Pembina owns or has interests in pipelines and related facilities to transport crude oil, condensate and natural gas liquids, gather and process natural gas; and provide midstream services in Alberta and British Columbia.

2. BASIS OF PREPARATION

a. Statement of compliance

The Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). These are the Company's first Financial Statements prepared in accordance with IFRS and IFRS-1 *(First-time Adoption of International Financial Reporting Standards.)*

An explanation of how transition from Canadian Generally Accepted Accounting Principles ("GAAP") has affected the reported financial position, financial performance and cash flows of the Company is provided in note 35. The note includes reconciliations of equity and total comprehensive income for comparative periods.

The Financial Statements were authorized for issue by the Board of Directors on February 15, 2012.

b. Basis of measurement

The Financial Statements have been prepared on the historical cost basis except for the following material items in the statement of financial position:

- derivative financial instruments are measured at fair value; and
- liabilities for cash-settled share-based payment arrangements are measured at estimated fair value.

c. Functional and presentation currency

The Financial Statements are presented in Canadian dollars, which is the Company's functional currency. All financial information presented in Canadian dollars has been disclosed in thousands except where noted.

d. Use of estimates and judgments

The preparation of the Financial Statements in conformity with IFRS requires management to make judgments, estimates and assumptions that are based on the circumstances and estimates at the date of the financial statements and affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Judgments, estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about judgments, assumptions and estimation uncertainties that have significant risk of resulting in a material adjustment within the next financial years are included in the following notes:

1. Defined benefit obligations

The calculation of the defined benefit obligation is sensitive to many estimates, but most significantly the discount rate applied.

2. Provisions and contingencies

Provisions recognized are based on management's judgment about assessing contingent liabilities and timing, scope and amount of liabilities. Management uses judgment in determining the likelihood of realization of contingent assets and liabilities to determine the outcome of contingencies.

Based on the long-term nature of the decommissioning provision, the biggest uncertainties in estimating the provision are the discount rates used, the costs that will be incurred and the timing of when these costs will occur. In addition, in determining the provision it is assumed that the Company will utilize technology and materials that are currently available.

3. Share-based payments

Compensation costs pursuant to the share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

4. Deferred taxes

The calculation of the deferred tax asset or liability is based on assumptions about the timing of many taxable events and the enacted or substantively enacted rates anticipated to apply to income in the years in which temporary differences are expected to be realized or reverse.

5. Depreciation and amortization

Estimated useful lives of property, plant and equipment is based on management's judgments and assumptions about the physical useful lives of the assets, the economic life, which may be associated with the reserve life and commodity type of the production area, in addition to the estimated residual value and the method by which the asset depreciates.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these Financial Statements and in preparing the opening IFRS statement of financial position at January 1, 2010 for the purpose of the transition to IFRS, unless otherwise indicated.

a. Basis of consolidation

i) Business combinations

Acquisitions on or after January 1, 2010

For acquisitions after January 1, 2010, the Company measures goodwill as the fair value of the consideration transferred including the recognized amount of any non-controlling interest in the acquiree, less the net recognized amount (generally fair value) of the identifiable assets acquired and liabilities assumed, all measured as of the acquisition date. When the excess is negative, a bargain purchase gain is recognized immediately in profit or loss.

The Company elects on a transaction-by-transaction basis whether to measure non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date.

Transaction costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

Acquisitions prior to January 1, 2010

As part of its transition to IFRS, the Company elected to not restate any business combinations that occurred before January 1, 2010. In respect of acquisitions prior to January 1, 2010, goodwill represents the amount recognized under previous Canadian GAAP.

ii) Subsidiaries

Subsidiaries are entities controlled by the Company. The financial statements of subsidiaries are included in the Financial Statements from the date that control commences until the date that control ceases. The accounting policies of subsidiaries are aligned with the policies adopted by the Company.

iii) Investments in associates and jointly controlled entities (equity accounted investees)

Associates are those entities in which the Company has significant influence, but not control, over the financial and operating policies. Significant influence is presumed to exist when the Company holds between 20 and 50 percent of the voting power of another entity. Joint ventures are those entities over whose activities the Company has joint control, established by contractual agreement and requiring unanimous consent for strategic financial and operating decisions.

The Financial Statements include the Company's share of the profit or loss and other comprehensive income, after adjustments to align the accounting policies with those of the Company, from the date that significant influence or joint control commences until the date that significant influence or joint control ceases. The Company's investments in its associates and joint ventures are accounted for using the equity method and are recognized initially at cost, including transaction costs.

When the Company's share of losses exceeds its interest in an equity accounted investee, the carrying amount of that interest, including any long-term investments, is reduced to nil, and the recognition of further losses is discontinued except to the extent that the Company has an obligation or has made payments on behalf of the investee.

iv) Jointly controlled operations

A jointly controlled operation is a joint venture carried on by each venture using its own assets in pursuit of the joint operations. The Financial Statements include the assets that the Company controls and the liabilities that it incurs in the course of pursuing the joint operation, and the expenses that the Company incurs and its share of the income that it earns from the joint operation.

v) Transactions eliminated on consolidation

Intra-group balances and transactions, and any unrealized revenue and expenses arising from intra-group transactions, are eliminated in preparing the consolidated financial statements. Unrealized gains arising from transactions with equity-accounted investees are eliminated against the investment to the extent of the Company's interest in the investee. Unrealized losses are eliminated in the same way as unrealized gains, but only to the extent that there is no evidence of impairment. Dilution gains and losses arising from changes in interests in investments in associates and joint ventures are recognized in the statement of comprehensive earnings.

vi) Foreign currency

Transactions in foreign currencies are translated to the Company's functional currency, Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies at the reporting date are retranslated to the Company's functional currency at the exchange rate at that date. The foreign currency gain or loss on monetary items is the difference between amortized cost in the functional currency at the beginning of the period, adjusted for effective interest and payments during the period, and the amortized cost in foreign currency translated at the exchange rate at the end of the reporting period. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are retranslated to the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on retranslation are recognized in profit or loss. Non-monetary items that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the date of the transaction. Foreign currency differences arising on retranslation are recognized in profit or loss.

b. Financial instruments

Financial assets and liabilities are offset and the net amount presented in the statement of financial position when, and only when, the Company has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

i) Non-derivative financial assets

The Company initially recognizes loans and receivables and deposits on the date that they are originated. All other financial assets (including assets designated at fair value through profit or loss) are recognized initially on the trade date at which the Company becomes a party to the contractual provisions of the instrument.

The Company derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by the Company is recognized as a separate asset or liability.

The Company classifies non-derivative financial assets into the following categories:

Cash and cash equivalents

Cash and cash equivalents comprise cash balances, call deposits and short term investments with original maturities of ninety days or less.

Trade and other receivables

Trade and other receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method less any impairment losses.

ii) Non-derivative financial liabilities

The Company initially recognizes debt securities issued and subordinated liabilities on the date that they are originated. All other financial liabilities (including liabilities designated at fair value through profit or loss) are recognized initially on the trade date at which the Company becomes a party to the contractual provisions of the instrument.

The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expire.

The Company's non-derivative financial liabilities are comprised of the following: trade payables and accrued liabilities, dividends payable, loans and borrowings including finance lease obligations and convertible debentures.

Such financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition these financial liabilities are measured at amortized cost using the effective interest method.

Bank overdrafts that are repayable on demand and form an integral part of the Company's cash management are included as a component of cash and cash equivalents for the purpose of the statement of cash flows.

iii) Share capital

Common shares

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

Trust units

Trust units which were outstanding in the comparative Statement of Financial Position (until Pembina's conversion to a corporation), are classified as a liability for purposes of the debt/equity allocation for convertible debentures. The trust units themselves, however, are presented as equity on the Statement of Financial Position and for purposes of calculating earnings per share.

iv) Compound financial instruments

Compound financial instruments issued by the Company comprise convertible debentures that can be converted to share capital at the option of the holder, and the number of shares to be issued does not vary with changes in their fair value.

The liability component of a compound financial instrument is recognized initially at the fair value of a similar liability that does not have an equity conversion option. The equity component is recognized initially as the difference between the fair value of the compound financial instrument as a whole and the fair value of the liability component. Any directly attributable transaction costs are allocated to the liability and equity components in proportion to their initial carrying amounts.

Subsequent to initial recognition, the liability component of a compound financial instrument is measured at amortized cost using the effective interest method. The equity component of a compound financial instrument is not remeasured subsequent to initial recognition.

Interest, losses and gains relating to the financial liability are recognized in profit or loss. On conversion, the financial liability is reclassified to equity; no gain or loss is recognized on conversion. After conversion, dividends to the equity holders are recognized in equity.

v) Derivative financial instruments

The Company holds derivative financial instruments to hedge its interest rate, commodity, power costs and foreign exchange risk exposures as well as convertible debentures during the comparative period with the convertible feature deemed to be a derivative based on the share unit classification as a liability. Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Derivatives are recognized initially at fair value with attributable transaction costs recognized in profit or loss as incurred. Subsequent to initial recognition, derivatives are measured at fair value and changes therein are recognized immediately in profit or loss in net finance costs.

c. Property, plant and equipment

i) Recognition and measurement

Items of property, plant and equipment are measured at cost less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour, any other costs directly attributable to bringing the assets to a working condition for their intended use, estimated decommissioning provisions and borrowing costs on qualifying assets.

Cost also may include any gain or loss realized on foreign currency transactions directly attributable to the purchase or construction of property, plant and equipment. Purchased software that is integral to the functionality of the related equipment is capitalized as part of that equipment.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate components of property, plant and equipment.

The gain or loss on disposal of an item of property, plant and equipment is determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment, and are recognized within other expense (income) in profit or loss.

ii) Subsequent costs

The cost of replacing a part of an item of property, plant and equipment is recognized in the carrying amount of the item if it is probable that the future economic benefits embodied within the part will flow to the Company, and its cost can be measured reliably. The carrying amount of the replaced part is derecognized. The cost of maintenance and repair expenses of the property, plant and equipment are recognized in profit or loss as incurred.

iii) Depreciation

Depreciation is based on the cost of an asset less its residual value. Significant components of individual assets, other than land, are assessed and if a component has a useful life that is different from the remainder of the asset, that component is depreciated separately.

Depreciation is recognized in profit or loss on a straight line or declining balance basis, which most closely reflects the expected pattern of consumption of the future economic benefits embodied in the asset. Pipeline assets and facilities are generally depreciated using the straight line method over 6 to 75 years (an average of 57.5 years) or declining balance method at rates ranging from 3 percent to 48 percent per annum (an average rate of 4.1 percent per annum). Storage assets and facilities are depreciated using the straight line method over 75 years or declining balance method at rates ranging from 3 percent to 48 percent. These rates are established to depreciate remaining net book value over the economic lives or contractual duration of the related assets.

Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

Depreciation methods, useful lives and residual values are reviewed at each financial year end and adjusted if appropriate. Estimates in respect of certain items of property, plant and equipment were revised in 2011.

d. Intangible assets

i) Goodwill

Goodwill that arises upon acquisitions is included in intangible assets. See note 3(a)(i) for the policy on measurement of goodwill at initial recognition.

Goodwill recognized prior to January 1, 2010, is included on the basis of its deemed cost, which represents the amount recorded under previous Canadian GAAP.

Subsequent measurement

Goodwill is measured at cost less accumulated impairment losses.

In respect of equity accounted investees, the carrying amount of goodwill is included in the carrying amount of the investment, and an impairment loss on such an investment is allocated to the investment and not to any asset, including goodwill, that forms the carrying amount of the equity accounted investee.

ii) Other intangibles

Other intangible assets acquired individually by the Company and have finite useful lives are recognized and measured at cost less accumulated amortization and accumulated impairment losses.

iii) Subsequent expenditures

Subsequent expenditures are capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. All other expenditures are recognized in profit or loss as incurred.

iv) Amortization

Amortization is based on the cost of an asset less its residual value.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. The estimated useful lives of other intangible assets is 33 years.

Amortization methods, useful lives and residual values are reviewed annually and adjusted if appropriate.

e. Leased assets

Leases which the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. The leased asset is initially recognized at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Other leases are operating leases and are not recognized in the Company's statement of financial position.

f. Inventories

Inventories are measured at the lower of cost and net realizable value and consist primarily of crude oil and other equipment. The cost of inventories is determined by the current month weighted average purchase price. The cost includes expenditures incurred in acquiring the inventories and other costs incurred in bringing them to their existing location and condition. Net realizable value is the estimated selling price in the ordinary course of business less the estimated selling costs. All changes in the value of the inventories are reflected in inventories and profit or loss.

g. Impairment

i) Non-derivative financial assets

A financial asset not carried at fair value through profit or loss is assessed at each reporting date to determine whether there is objective evidence that it is impaired. A financial asset is impaired if a loss event has occurred after the initial recognition of the asset, and that the loss event had a negative effect on the estimated future cash flows of that asset and the impact can be estimated reliably.

Objective evidence that financial assets are impaired can include default or delinquency by a debtor, restructuring of an amount due to the Company on terms that the Company would not consider otherwise, indications that a debtor or issuer will enter bankruptcy, adverse changes in the payment status of borrowers or issuers in the Company, economic conditions that correlate with defaults or the disappearance of an active market for a security or a significant or prolonged decline in the fair value below cost.

Trade and other receivables ("Receivables")

The Company considers evidence of impairment for Receivables at both a specific asset and collective level. All individually significant Receivables are assessed for specific impairment. All individually significant Receivables found not to be specifically impaired are then collectively assessed for any impairment that has been incurred but not yet identified. Receivables that are not individually significant are collectively assessed for impairment by grouping together Receivables with similar risk characteristics.

In assessing collective impairment the Company uses historical trends of the probability of default, timing of recoveries and the amount of loss incurred, adjusted for management's judgment as to whether current economic and credit conditions are such that the actual losses are likely to be greater or less than suggested by historical trends.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the asset's original effective interest rate. Losses are recognized in profit or loss and reflected in an allowance account against Receivables. Interest on the impaired asset continues to be recognized through the unwinding of the discount. When a subsequent event causes the amount of impairment loss to decrease, the decrease in impairment loss is reversed through profit or loss.

ii) Non-financial assets

The carrying amounts of the Company's non-financial assets, other than inventories, line fill and assets arising from employee benefits and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For goodwill and intangible assets that have indefinite useful lives or that are not yet available for use, the recoverable amount is estimated each year at the same time. An impairment loss is recognized if the carrying amount of an asset or its related Cash Generating Unit ("CGU") exceeds its estimated recoverable amount.

The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU. For the purpose of impairment testing, assets that cannot be tested individually are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or CGUs. Subject to an operating segment ceiling test, for the purpose of goodwill impairment testing, CGUs to which goodwill has been allocated are aggregated so that the level at which impairment testing is performed reflects the lowest level at which goodwill is monitored for internal purposes. Goodwill acquired in a business combination is allocated to CGUs or groups of CGUs that are expected to benefit from the synergies of the combination.

The Company's corporate assets do not generate separate cash inflows and are utilized by more than one CGU. Corporate assets are allocated to CGUs on a reasonable and consistent basis and tested for impairment as part of the testing of the CGU to which the corporate asset is allocated. If there is an indication that a corporate asset may be impaired, then the recoverable amount is determined for the CGU to which the corporate asset belongs.

Impairment losses are recognized in profit or loss. An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGU (group of CGUs), and then to reduce the carrying amounts of the other assets in the CGU (group of CGUs) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

Goodwill that forms part of the carrying amount of an investment in an associate is not recognized separately, and therefore is not tested for impairment separately. Instead, the entire amount of the investment in an associate is tested for impairment as a single asset when there is objective evidence that the investment in an associate may be impaired.

h. Employee benefits

i) Defined contribution plans

A defined contribution plan is a post-employment benefit plan under which an entity pays fixed contributions into a separate entity and will have no legal or constructive obligation to pay further amounts. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss in the periods during which services are rendered by employees. Prepaid contributions are recognized as an asset to the extent that a cash refund or a reduction in future payments is available. Contributions to a defined contribution plan that are due more than 12 months after the end of the period in which the employees render the service are discounted to their present value.

ii) Defined benefit pension plans ("Plans")

A defined benefit pension plan is a post-employment benefit plan other than a defined contribution plan. The Company's net obligation in respect of defined benefit pension plans is calculated separately for each plan by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods, discounted to determine its present value. Unrecognized past service costs and the fair value of any plan assets are deducted. The discount rate used to determine the present value is comprised of the following: estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plans investment policy, additional net returns assumed to be achievable due to active equity management, implicit provision for expenses determined as the average rate of investment and administrative expenses paid by the Plans over the last five years, and a margin for adverse deviations, based on the proportion of the Plans assets invested in equities in excess of the return expected on equities, over government bond yields.

The calculation is performed, at a minimum, every three years by a qualified actuary using the actuarial cost method. When the calculation results in a benefit to the Company, the recognized asset is limited to the total of any unrecognized past service costs and the present value of economic benefits available in the form of any future refunds from the plan or reductions in future contributions to the plan. In order to calculate the present value of economic benefits, consideration is given to any minimum funding requirements that apply to any plan in the Company. An economic benefit is available to the Company if it is realizable during the life of the plan, or on settlement of the plan liabilities.

When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized in profit or loss on a straight-line basis over the average period until the benefits become vested. To the extent that the benefits vest immediately, the expense is recognized immediately in profit or loss.

All actuarial gains and losses at January 1, 2010, the date of transition to IFRS, were recognized in the deficit. The Company recognizes all actuarial gains and losses arising subsequently from defined benefit plans in other comprehensive income and expenses related to defined benefit plans in personnel expenses in profit or loss.

The Company recognizes gains or losses on the curtailment or settlement of a defined benefit plan when the curtailment or settlement occurs. The gain or loss on curtailment comprises any resulting change in the fair value of plan assets, change in the present value of defined benefit obligation and any related actuarial gains or losses and past service cost that had not previously been recognized.

iii) Other long-term employee benefits

The Company's net obligation in respect of long-term employee benefits other than pension plans is the amount of future benefit that employees have earned in return for their service in the current and prior periods; is discounted to determine its present value, and the fair value of any related assets is deducted. The discount rate is comprised of the following: estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plans investment policy, additional net returns assumed to be achievable due to active equity management, implicit provision for expenses determined as the average rate of investment and administrative expenses paid from the Plans over the last five years, and a margin for adverse deviations, based on the proportion of the Plans assets invested in equities in excess return expected on equities, over government bond yields.

The calculation is performed using an actuary.

iv) Short-term employee benefits

Short-term employee benefit obligations are measured on an undiscounted basis and are expensed as the related service is provided.

A liability is recognized for the amount expected to be paid under short-term cash bonus if the Company has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

v) Share-based payment transactions

For equity settled share-based payment plans, the fair value of share-based payment at grant date is recognized as an expense, with a corresponding increase in equity, over the period that the employees unconditionally become entitled to the awards. The amount recognized as an expense is adjusted to reflect the number of awards for which the related service and non-market vesting conditions are expected to be met, such that the amount ultimately recognized as an expense is based on the number of awards that meet the related service conditions at the vesting date.

For cash settled share-based payment plans, the fair value of the amount payable to employees is recognized as an expense with a corresponding increase in liabilities, over the period that the employees unconditionally become entitled to payment. The liability is remeasured at each reporting date and at settlement date. Any changes in the fair value of the liability are recognized as an expense in profit or loss.

i. Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are remeasured at each reporting date based on the best estimate of the settlement amount. The unwinding of the discount rate (accretion) is recognized as a finance cost.

i) Decommissioning provision

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. A provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value, based on a risk free rate, of management's best estimate of expenditure required to settle the obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the risk free rate and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows or risk free rate are added to or deducted from the cost of the related asset.

ii) Other

In accordance with the Company's environmental practices, industry practice, regulations and applicable legal requirements, a provision for site restoration in respect of contaminated land, and the related expense, is recognized when the land is contaminated and an estimate can reasonably be made.

j. Revenue

Revenue in the course of ordinary activities is measured at the fair value of the consideration received or receivable. Revenue is recognized when persuasive evidence exists that the significant risks and rewards of ownership have been transferred to the customer or the service has been provided, recovery of the consideration is probable, the associated costs can be estimated reliably, there is no continuing management involvement with the goods, and the amount of revenue can be measured reliably.

The timing of the transfer of significant risks and rewards varies depending on the individual terms of the sales or service agreement. For product sales, usually transfer of significant risks and rewards occurs when the product is delivered to a customer. For pipeline transportation revenues and storage revenue, transfer of significant risks and rewards usually occurs when the service is provided as per the contract with the customer. For rate or contractually regulated pipeline operations, revenue is recognized in a manner that is consistent with the underlying rate design as mandated by agreement or regulatory authority.

Certain pipelines have been designated single-shipper lines where producers must either sell their product at the inlet point at which point revenue is recognized or are considered buy/sell transactions where the producer sells their product at the inlet point and repurchases it at the delivery point for the inlet price paid plus an agreed-upon differential on a pre-arranged basis. The buy/sell transactions are recorded when the services have been provided and recognized on a net basis in profit or loss. Product sales and purchases for terminalling, storage and hub services are recognized on a gross basis in the statement of earnings.

k. Lease payments

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

Minimum lease payments made under finance leases are apportioned between the finance cost and the reduction of the outstanding liability. The finance cost is allocated to each period during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability. Contingent lease payments are accounted for by revising the minimum lease payments over the remaining life.

i) Determining whether an arrangement contains a lease

At inception of an arrangement, the Company determines whether such an arrangement is or contains a lease. A specific asset is the subject of a lease if fulfilment of the arrangement is dependent on the use of that specified asset. An arrangement conveys the right to use the asset if the arrangement conveys to a lessee the right to control the use of the underlying asset.

At inception or upon reassessment of the arrangement, the Company separates payments and other consideration required by such an arrangement into those for the lease and those for other elements on the basis of their relative fair values. If the Company concludes for a finance lease that it is impracticable to separate the payments reliably, an asset and a liability are recognized at an amount equal to the fair value of the underlying asset. Subsequently the liability is reduced as payments are made and an imputed finance cost on the liability is recognized using the Company's incremental borrowing rate.

l. Finance income and finance costs

Finance income comprises interest income on funds deposited and invested, gains in derivatives measured at fair value through profit or loss and foreign exchange gains. Interest income is recognized as it accrues in profit or loss, using the effective interest method.

Finance costs comprise interest expense on loans and borrowings, unwinding of discount rate on provisions, losses on disposal of available for sale financial assets, losses on financial assets recognized at fair value through profit or loss, impairment losses recognized on financial assets (other than trade and other receivables) foreign exchange losses and losses on derivative financial instruments that are recognized in profit or loss.

Borrowing costs that are not directly attributable to the acquisition, or construction of a qualifying asset are recognized in profit or loss using the effective interest method.

Foreign currency gains and losses are reported on a net basis as either finance income or finance cost depending on whether foreign currency movements are in a net gain or net loss position.

m. Income tax

Income tax expense comprises current and deferred tax. Current and deferred tax are recognized in profit or loss except to the extent that it relates to a business combination, or items are recognized directly in equity or in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for:

- temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss;
- temporary differences relating to investments in subsidiaries and jointly controlled entities to the extent that it is probable that they will not reverse in the foreseeable future;
- taxable temporary differences arising on the initial recognition of goodwill.

Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

n. Earnings per share

The Company presents basic and diluted earnings per share ("EPS") data for its common shares. Basic EPS is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted EPS is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding, for the effects of all potentially dilutive common shares, which comprise convertible debentures and share options granted to employees ("Convertible Instruments"). Only outstanding and Convertible Instruments that will have a dilutive effect are included in fully diluted calculations.

The dilutive effect of Convertible Instruments is determined whereby outstanding Convertible Instruments at the end of the period are assumed to have been converted at the beginning of the period or at the time issued if issued during the year. Amounts charged to income or loss relating to the outstanding Convertible Instruments are added back to net income for the diluted calculations. The shares issued upon conversion are included in the denominator of per share basic calculations for the date of issue.

Earnings per unit in the comparative period are calculated assuming the units were recognized as equity.

o. Segment reporting

An operating segment is a component of the Company that engages in business activities from which it may earn revenues and incur expenses, including revenues and expenses that relate to transactions with any of the Company's other components. All operating segments' operating results are reviewed regularly by the Company's Chief Executive Officer ('CEO"), Chief Financial Officer ("CFO") and Chief Operating Officer ("COO") to make decisions about resources to be allocated to the segment and assess its performance, and for which discrete financial information is available.

Segment results that are reported to the CEO, CFO and COO include items directly attributable to a segment as well as those that can be allocated on a reasonable basis. Unallocated items comprise mainly corporate assets, head office expenses, finance income and costs and income tax assets and liabilities.

Segment capital expenditure is the total cost incurred during the period to acquire property, plant and equipment, and intangible assets other than goodwill.

p. Cash flow statement

The cash flow statement is prepared using the indirect method. Changes in balance sheet items that have not resulted in cash flows such as equity-settled share-based payments, unrealized gains and losses, depreciation and amortization, and employee future benefit expenses, among others, have been eliminated for the purpose of preparing this statement. Assets and liabilities acquired as part of a business combination are included in investing activities (net of cash acquired). Dividends paid to ordinary shareholders, distributions from equity accounted investees, employee future benefit contributions, decommissioning liability expenditures, among other expenditures, are included in financing activities. Interest paid is included in operating activities.

q. New standards and interpretations not yet adopted

Certain new standards, interpretations, amendments and improvements to existing standards were issued by the IASB or International Financial Reporting Interpretations Committee ("IFRIC") that are available for early adoption for accounting periods beginning after January 1, 2010. The Company has reviewed these and determined that the following may have an impact on the Company:

IFRS 9 (2010) *Financial Instruments* supersedes IFRS 9 (2009) *Financial Instruments* and is effective for annual periods beginning on or after January 1, 2013, with early adoption permitted. For annual periods beginning before January 1, 2013, either IFRS 9 (2009) or IFRS 9 (2010) may be applied. An exposure draft was issued in August 2011 proposing to change the mandatory effective date to annual periods beginning on or after January 1, 2015. The Company intends to adopt IFRS 9 (2010) in its financial statements for the annual period beginning on January 1, 2015. The extent of the impact of adoption of IFRS 9 (2010) has not yet been determined.

IFRS 10 *Consolidated Financial Statements*, IFRS 11 *Joint Arrangements,* IFRS 12 *Disclosure of Interest in Other Entities* and IFRS 13 *Fair Value Measurement* are effective for annual periods beginning on or after January 1, 2013, with early adoption permitted. The Company intends to adopt IFRS 10, IFRS 11, IFRS 12 and IFRS 13 in its financial statements for the annual period beginning on January 1, 2013. The extent of the impact has not yet been determined.

4. DETERMINATION OF FAIR VALUES

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

i) Property, plant and equipment

The fair value of property, plant and equipment recognized as a result of a business combinations is based on market values when available and replacement cost when appropriate.

ii) Intangible assets

The fair value of customer relationships and service contracts acquired in a business combination is determined using the multi-period excess earnings method, whereby the subject asset is valued after deducting a fair return on all other assets that are part of creating the related cash flows.

The fair value of other intangible assets is based on the discounted cash flows expected to be derived from the use and eventual sale of the assets.

iii) Derivatives

Fair value of derivatives is estimated by discounting the difference between the contractual forward price or rate and the current market price or rate for the residual maturity of the contract.

Fair values reflect the credit risk of the instrument and include adjustments to take account of the credit risk of the Company entity and counterparty when appropriate.

iv) Non-derivative financial assets and liabilities

Fair value, which is determined for disclosure purposes, is calculated based on the present value of future principal and interest cash flows, discounted at the market rate of interest at the reporting date. In respect of the convertible debentures, the fair value is determined by the market price of the convertible debenture on the reporting date. For finance leases the market rate of interest is determined by reference to similar lease agreements.

v) Share-based payment transactions

The fair value of the employee share options is measured using the Black-Scholes formula. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, expected forfeitures and the risk-free interest rate (based on government bonds). Service and non-market performance conditions attached to the transactions are not taken into account in determining fair value.

The fair value of the long-term share unit award incentive plan and the associated distribution units are measured based on the reporting date market price of the Company's shares. Expected dividends are not taken into account in determining fair value as they are issued as additional distribution share units.

vi) Inventories

The net realizable value of inventories is determined based on the estimated selling price in the ordinary course of business less estimated cost to sell.

5. CASH AND CASH EQUIVALENTS

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Bank balances		43,314	5,903
Call deposits		82,083	48,024
Short term investments			
Cash and cash equivalents		125,397	53,927
Bank overdrafts used for cash management purposes	(676)		
	(676)	125,397	53,927

6. TRADE AND OTHER RECEIVABLES

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Trade accounts receivables from customers	116,809	90,508	80,520
Trade accounts receivable and other receivables from related parties	28,864	11,454	
Prepayments	2,594	3,512	2,724
Other			
Total current trade and other receivables	148,267	105,474	83,244
Receivable due from related parties	10,814		
	159,081	105,474	83,244

7. INVENTORY

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Crude oil, condensate and NGLs	21,236	26,099	18,998
Spare parts and equipment	1,547		
Inventory, carrying amount	22,783	26,099	18,998

8. PROPERTY, PLANT AND EQUIPMENT

($ thousands)	Land and Land Rights	Pipelines	Facilities and Equipment	Linefill and Other	Assets Under Construction	Total
Cost						
Balance at January 1, 2010	57,194	1,910,592	468,426	149,920	119,614	2,705,746
Additions	3	78,419	5,226	3,752	168,801	256,201
Transfers	51	8,256	12,660	6,629	(27,596)	
Disposals			(2,547)	(11,184)		(13,731)
Balance at December 31, 2010	57,248	1,997,267	483,765	149,117	260,819	2,948,216
Additions	10,006	333,991	30,208	50,550	232,211	656,966
Transfers	104	169,354	15,075	1,139	(185,672)	
Disposals	(139)	(585)	(428)	(1,628)		(2,780)
Balance at December 31, 2011	67,219	2,500,027	528,620	199,178	307,358	3,602,402
Depreciation						
Balance at January 1, 2010	3,999	619,291	63,942	52,831		740,063
Depreciation	44	39,986	14,901	7,644		62,575
Disposals			(2,345)	(11,174)		(13,519)
Balance at December 31, 2010	4,043	659,277	76,498	49,301		789,119
Depreciation	45	48,334	16,768	4,374		69,521
Disposals		(516)	(268)	(1,436)		(2,220)
Balance at December 31, 2011	4,088	707,095	92,998	52,239		856,420
Carrying amounts						
At January 1, 2010	53,195	1,291,301	404,484	97,089	119,614	1,965,683
At December 31, 2010	53,205	1,337,990	407,267	99,816	260,819	2,159,097
At December 31, 2011	63,131	1,792,932	435,622	146,939	307,358	2,745,982

Leased asset

The Company leases vehicles under a finance lease agreement. At December 31, 2011 the net carrying amount of leased vehicles was $5.6 million (2010: $4.6 million; January 1, 2010: $4.5 million).

Property, plant and equipment under construction

During the year ended December 31, 2011, the Company completed construction on the Nipisi and Mitsue Pipelines. Costs of assets under construction at December 31, 2011 totalled $307.4 million. Cost of assets under construction as at December 31, 2010 totalled $260.8 million ($176.8 million for Nipisi and Mitsue Pipelines). Such amounts include capitalized borrowing costs.

For the year ended December 31, 2011, capitalized borrowing costs related to the construction of the new pipelines or facilities amounted to $10.2 million (2010: $6.4 million), with capitalization rates ranging from 4.91 percent to 5.36 percent (2010: 5.08 percent to 5.39 percent).

Commitments

At December 31, 2011, the Company has contractual commitments for the acquisition and or construction of property, plant and equipment of $364.3 million (December 31, 2010: $345.8 million).

9. INTANGIBLE ASSETS

($ thousands)	Goodwill	Other Intangibles	Total
Cost			
Balance at January 1, 2010, December 31, 2010 and 2011	222,670	23,038	245,708
Amortization			
Accumulated amortization at January 1, 2010		408	408
Amortization		698	698
Accumulated amortization at December 31, 2010		1,106	1,106
Amortization		698	698
Accumulated amortization at December 31, 2011		1,804	1,804
Carrying amounts			
January 1, 2010	222,670	22,630	245,300
December 31, 2010	222,670	21,932	244,602
December 31, 2011	222,670	21,234	243,904

Other intangible assets consist of customer contracts with several producers acquired through business combinations and have a remaining amortization period of 33 years.

The aggregate carrying amount of intangible assets allocated to each cash generating unit are as follows:

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Conventional Pipelines	194,370	194,370	194,370
Oil Sands and Heavy Oil	28,300	28,300	28,300
Gas Services	21,234	21,932	22,630
	243,904	244,602	245,300

Amortization

Amortization of other intangibles is recognized in cost of sales.

Impairment testing

For the purpose of impairment testing, goodwill is allocated to the Company's operating divisions which represent the lowest level within the Company at which the goodwill is monitored for internal management purposes, which is not higher than the Company's operating segments. Impairment testing for goodwill was performed on December 31, 2011. The recoverable amounts were based on their value in use and were determined to be higher than their carrying amounts.

Value in use was determined by discounting the future cash flows generated from the continuing use of each cash generating unit. The calculation of the value in use was based on the following key assumptions:

Cash flows were projected based on past experience, actual operating results and the first 5 years of the business plan approved by management. Cash flows for periods up to 75 years (2010 – 75 years) were extrapolated using a constant growth rate of 1.9 percent (2010 – 1.6 percent), which does not exceed the long-term average growth rate for the industry. Pre-tax discount rates between 7.51 percent and 8.84 percent (2010 – 9.69 percent and 10.74 percent) were applied in determining the recoverable amount of the units. The discount rates were estimated based on past experience, the Company's risk free rate and average cost of debt in addition to estimates of the specific cash generating unit's equity risk premium, size premium, small capitalization premium, projection risk, betas, tax rate and industry targeted debt to equity ratios.

10. INVESTMENTS IN EQUITY ACCOUNTED INVESTEES

The Company has a 50 percent interest in two jointly controlled, equity accounted investees that are reported using the equity method of accounting. The carrying value of the investment at December 31, 2011 is $161.0 million (2010: $190.7 million).

	Balance as at				Transaction Value Year Ended			
	Current Assets	Non-Current Assets	Current Liabilities	Non-Current Liabilities	Revenues	Expenses	Profit and Loss	Cash Distributions Received
($ thousands)								
Fort Saskatchewan Ethylene Storage Corporation (FSESC)	258	37						
Fort Saskatchewan Ethylene Storage Limited Partnership (FSESLP)	2,684	8,354	882					
January 1, 2010	2,942	8,391	882					
FSESC	284	33			31	8	23	
FSESLP	9,421	7,823	9,055		22,947	6,326	16,621	17,328
December 31, 2010	9,705	7,856	9,055		22,978	6,334	16,644	17,328
FSESC	316	11	1		78	2	76	
FSESLP	3,271	26,216	20,125	12,087	45,925	7,082	38,843	16,869
December 31, 2011	3,587	26,227	20,126	12,087	46,003	7,084	38,919	16,869

On acquisition, Pembina recognized a fair value adjustment which is amortized over the useful life of the assets. Pembina's share of profit of investments in equity accounted investees includes amortization of the fair value adjustment of $5.2 million (2010: $5.6 million), derecognition of fair value adjustment of $25.2 million, income taxes of $1.9 million (2010: $2.6 million) and other $0.7 million (2010: $0.7 million).

Commitments

At December 31, 2011, the Company's share of investment in equity accounted investees contractual commitments for the construction of property, plant and equipment is $42.7 million (December 31, 2010: $7.8 million).

11. INCOME TAXES

The components of the Company's deferred tax liability are as follows:

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Property, plant and equipment	203,178	155,160	125,834
Intangible assets	(2,512)	(2,017)	(2,695)
Investments in equity accounted investees	25,802	27,927	28,873
Derivative financial instruments	(2,772)	(2,351)	(1,445)
Employee benefits	(4,238)	(1,472)	(835)
Share-based payments	(3,515)	(1,355)	(1,231)
Provisions	(101,358)	(70,424)	(54,276)
Taxable limited partnership income deferral	50,175	41,413	54,058
Benefit of loss carry forwards	(62,426)	(82,565)	(73,852)
Other	4,581	5,370	1,408
	106,915	69,686	75,839

The Company's consolidated effective tax rate for the year ending December 31, 2011 was 19.6 percent (2010: 5.3 percent).

Reconciliation of effective tax rate

($ thousands)	**2011**	2010
Earnings before income tax	198,769	158,407
Statutory tax rate	26.5%	28%
Income tax at statutory rate	52,674	44,354
Tax rate changes on deferred income tax balances	(5,051)	(6,733)
Interest deductions of subsidiaries arising from intercorporate debt		(42,590)
Changes in estimate from prior year	(8,880)	(6,268)
Other	126	2,917
Income tax expense (reduction)	38,869	(8,320)

Income tax expense

($ thousands)	**December 31 2011**	December, 31 2010
Current tax expense		
Adjustment for prior period		(1,058)
Total current tax expense (reduction)		(1,058)
Deferred tax expense		
Origination and reversal of temporary differences	23,826	10,982
Tax rate changes on deferred tax balances	(5,075)	(6,733)
Decrease (increase) in tax loss carry forward	20,118	(11,511)
Total deferred tax expense (reduction)	38,869	(7,262)
Total income tax expense (reduction)	38,869	(8,320)

The movement in deferred taxes during the year was reported in:

($ thousands)	**December 31 2011**	December, 31 2010
Income tax expense	38,869	(7,262)
Share of profit of equity accounted investee	1,900	2,635
Other comprehensive income	(3,540)	(1,526)
	37,229	(6,153)

12. TRADE PAYABLES AND ACCRUED LIABILITIES

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Trade payables	141,452	80,528	44,543
Non-trade payables & accrued liabilities	14,474	18,495	13,696
	155,926	99,023	58,239

13. LOANS AND BORROWINGS

This note provides information about the contractual terms of the Company's interest-bearing loans and borrowings, which are measured at amortized cost.

Carrying value terms and debt repayment schedule

Terms and conditions of outstanding loans were as follows:

($ thousands)	Available facilities at Dec. 31, 2011	Nominal interest rate	Year of maturity	Dec. 31, 2011	Dec. 31, 2010	Jan. 1 2010
				Carrying amount[3]		
Operating facility[1]	50,000	prime + 0.35 or BA[2] + 1.35	2012	3,139		
Revolving unsecured credit facility	500,000	prime or BA[2] + 0.50	2012	309,981	239,949	199,898
Non-revolving unsecured term facility	75,000	6.16	2014	74,658	74,517	74,355
Non-revolving unsecured credit facility		prime + 1.75				148,798
Senior unsecured notes – Series A	175,000	5.99	2014	174,462	174,247	173,995
Senior unsecured notes – Series C	200,000	5.58	2021	196,638	196,293	195,944
Senior unsecured notes – Series D	267,000	5.91	2019	265,403	265,201	265,230
Senior secured notes	57,978	7.38	2017	57,499	65,395	72,724
Senior unsecured medium term notes	250,000	4.89	2021	248,558		
Finance lease liabilities				5,650	4,555	4,462
Total interest-bearing liabilities	1,574,978			1,335,988	1,020,157	1,135,406
Less current portion				(323,927)	(10,055)	(159,324)
Total non-current				1,012,061	1,010,102	976,082
Operating facility				3,139		
Revolving unsecured credit facility				310,000		150,000
Senior secured notes				8,581	7,981	7,423
Finance lease liabilities				2,207	2,074	1,901
Total current portion				323,927	10,055	159,324

(1) Operating facility expected to be renewed on an annual basis.
(2) Bankers Acceptance.
(3) Deferred financing fees are all classified as non current. Non current carrying amount of facilities are net of deferred financing fees.

All facilities are governed by specific debt covenants which Pembina has been in compliance with during the years ending December 31, 2011 and 2010.

Senior secured notes are secured by Pembina's total consolidated assets and those of its material subsidiaries.

For more information about the Company's exposure to interest rate, foreign currency and liquidity risk, see Financial risk management and financial instruments note 28.

Convertible debentures

($ thousands)	5.75%	7.35%
Balance, January 1, 2010 (current)		36,640
Proceeds (net of transaction costs of $11,365)	288,635	
Conversions		(35,433)
Repayments		(1,207)
Balance, December 31, 2010 (non-current)	288,635	
Deferred financing fee (net amortization)	950	
Conversions	(220)	
Balance, December 31, 2011 (non-current)	289,365	

On November 24, 2010 the Company issued 5.75 percent convertible unsecured subordinated debentures that mature on November 30, 2020, with interest payable semi-annually in arrears on May 31 and November 30. The debentures may be converted at the option of the holder at a conversion price of $28.55 per share at any time prior to maturity and may be redeemed by the Company. The Company may, at its option after November 30, 2016, (or after November 30, 2014, provided that the volume weighted average trading price of the common shares on the TSX during the 20 consecutive trading days ending on the fifth trading day preceeding the date on when the notice of redemption is given is not less than 125 of the conversion price of the debentures) elect to redeem the debentures by issuing shares. The Company may also elect to pay interest on the debentures by issuing shares.

The Company did not allocate a portion of the convertible debentures to equity as the calculation of the equity component was not significant when such an allocation was based on an approximate interest rate that would have been applicable to the issuance of similar debt without the conversion features at the time the debentures were issued.

The 7.35 percent convertible unsecured subordinated debentures matured on December 31, 2010, with interest paid semi-annually in arrears on June 30 and December 31. The debentures were convertible at the option of the holder at a conversion price of $12.50 per share at any time prior to maturity and were redeemable by the Company.

Based on the redemption feature embedded in the convertible instrument, the Company recognized the debenture as a hybrid instrument and applied two step accounting; recognizing the debt component at amortized cost and recognizing the convertible feature at fair value through profit or loss. At October 1, 2010, post the conversion from an Income Fund to a Corporation, Pembina re-classified the convertible debenture as a compound financial instrument and did not allocate a portion of the convertible debentures to equity as the calculation of the equity component was not significant when such an allocation was based on an approximate interest rate that would have been applicable to the issuance of similar debt without the conversion features at the time the debentures were issued.

Finance lease liabilities

Finance lease liabilities are payable as follows:

	Present Value of Minimum Lease Payments	**Present Value of Minimum Lease Payments**	**Present Value of Minimum Lease Payments**
($ thousands)	**Dec. 31, 2011**	**Dec. 31, 2010**	**Jan. 1, 2010**
Less than one year	2,207	2,074	1,901
Between one and five years	3,440	2,481	2,551
More than five years	3		10
	5,650	4,555	4,462

Finance lease liabilities relate to vehicle leases under a Master Vehicle Lease Agreement, which have been determined to be a finance lease as the risks and rewards of ownership of the vehicles leased have been transferred to the Company. The significant terms of this lease agreement are:

a) The lease term is determined for each vehicle individually but for a minimum of one year;

b) At the end of the lease term, the Company has the right to keep the asset by option of paying the payout value to the lessor or selling the asset through the lessor;

c) If the vehicle at the end of the lease term is sold by the lessor for less than its payout value (calculated as the vehicle cost at the inception of the lease less the interest adjusted monthly lease cost over the lease term), the Company pays the lessor the difference. If the vehicle at the end of the lease term is sold for more than its payout value, the lessor pays the Company the difference;

d) The lessor remains the owner of the vehicles and they are registered as such; and

e) Interest rates implicit in the leases range from 5.48 percent to 9.73 percent.

14. PROVISIONS

The Company's activities give rise to dismantling, decommissioning and site remediation activities. A provision is made for the estimated cost of site restoration and capitalized in the relevant asset category or expensed in the period.

Decommissioning

The Company has estimated the net present value of its total decommissioning obligations based on a total future liability (with the current change in estimate adjusted for 2.4 percent inflation per annum, based on the Alberta CPI inflation average) of $401.5 million (2010: $277.2 million). The new estimate includes a revision of the timing of payments. The obligations are expected to be paid over the next 100 years with substantially all being paid between 30 and 50 years. The Company used a risk free rate of 2.49 percent to calculate the present value of the decommissioning provision. During the year ending December 31, 2011, the Company estimated an increase of $124.4 million, including a $105.6 million (2010: $65.2 million) increase based on a decrease in the discount rate used to remeasure the obligation and a $11.8 million increase representing the present value of additional obligations relating to the Nipisi and Mitsue Pipelines and $10.0 million for unwinding of the discount rate, net of any settlements. The remeasured decommissioning provision was based on a change in the discount rate from 3.54 percent to 2.49 percent in 2011 (4.08 percent to 3.54 percent in 2010) which increased property, plant and equipment and decommissioning provision liability.

The property, plant and equipment of the Company consist primarily of underground pipelines, above ground equipment facilities and storage assets. No amount has been recorded relating to the removal of the underground pipelines or the storage assets as the potential obligations relating to these assets cannot be reasonably estimated due to the indeterminate timing or scope of the asset retirement. As the timing and scope of retirement become determinable for these assets, the fair value of the liability and the cost of retirement will be recorded.

Other

The Company has recognized a $9.2 million provision relating to the costs yet to be incurred for the Swan Hills incident (all of which is expected to be recovered by insurance).

($ thousands)	Decommissioning	Other	Total
Balance at January 1, 2010	213,569	3,534	217,103
Change in estimates	(9,835)		(9,835)
Unwinding of discount rate	8,228	144	8,372
Provisions settled during the period			
Change in discount rate	65,222	832	66,054
Balance at December 31, 2010	277,184	4,510	281,694
Unwinding of discount rate	9,986	155	10,141
Provisions incurred during the period	11,848	9,237	20,648
Provisions settled during the period	(3,123)		(3,123)
Change in discount rate	105,642	714	106,793
Balance at December 31, 2011	401,537	14,616	416,153
Non-current	401,537	3,896	405,433
Current(1)		10,720	10,720

(1) Included in accrued liabilities

15. CAPITAL AND OTHER COMPONENTS OF EQUITY

Shareholder's capital

Pembina is authorized to issue an unlimited number of no par value voting common shares and preferred shares. The holders of the common shares are entitled to receive notice of, attend at and vote at any meeting of the shareholders of the Company, receive dividends declared and share in the remaining property of the Company upon distribution of the assets of the Company among its shareholders for the purpose of winding-up its affairs.

($ thousands)	Number	Shareholder's Capital
Balance January 1, 2010	158,588,699	1,657,803
Exercise of stock options, debenture conversions and dividend reinvestment plan	8,287,952	136,465
Other		268
Balance December 31, 2010	166,876,651	1,794,536
Exercise of stock options and debenture conversions	1,031,620	16,941
Other		257
Balance December 31, 2011	167,908,271	1,811,734

The Company has issued share options (see note 26) and convertible debentures (see note 13).

Accumulated Other Comprehensive Income (AOCI)

AOCI is comprised of Actuarial gains and losses on the pension asset and obligation recorded in Other Comprehensive Income, net of the related tax effect.

Dividends

The following dividends were declared and paid by the Company:

($ thousands)	**2011**	2010
$1.56 per qualifying common share	261,236	255,151

After December 31, 2011, the December dividend declaration of 0.13 cents per month per qualifying common share were declared by the Board of Directors in the amount of $21.8 million.

16. REVENUES

($ thousands)	**2011**	2010
Rendering of Services:		
Conventional pipeline transportation	296,190	261,617
Oil Sands and Heavy Oil pipeline transportation	134,874	118,420
Midstream and marketing terminalling, storage and hub services (net)	1,174,140	790,655
Gas services gathering and processing services	71,506	61,498
	1,676,710	1,232,190

17. COST OF SALES

($ thousands)	**2011**	2010
Operating expense	191,923	155,818
Product purchases	1,072,048	735,223
Depreciation and amortization – operating	68,012	61,652
	1,331,983	952,693

18. GENERAL & ADMINISTRATIVE

($ thousands)	**2011**	2010
Other general & administrative expense	59,984	47,009
Depreciation and amortization – general and administrative	2,207	1,622
	62,191	48,631

19. DEPRECIATION AND AMORTIZATION

($ thousands)	**2011**	2010
Cost of sales	68,012	61,652
General and administrative	2,207	1,622
	70,219	63,274

20. PERSONNEL EXPENSES

($ thousands)	2011	2010
Salaries and wages	57,564	49,147
Canada Pension Plan (CPP) and EI remittances	1,717	1,448
Share-based payment transactions	18,651	14,871
Short term incentive plan (bonus)	8,393	3,710
Defined contribution plan expense	878	548
Defined benefit pension plan expense	4,828	4,698
Health and dental benefit expense	2,232	1,956
Employee savings plan expense	2,172	1,993
Other benefits	1,064	1,074
	97,499	79,445

21. NET FINANCE COSTS

($ thousands)	2011	2010
Interest income on:		
Loans to related parties(1)	876	168
Bank deposits	414	374
Foreign exchange gains	84	
Realized gains on power derivatives	4,413	
Finance income	5,787	542
Interest expense on financial liabilities measured at amortized cost:		
Loans and borrowings	56,722	56,062
Convertible debentures	18,415	4,000
Finance leases	404	344
Unwinding of discount	10,141	8,372
Change in fair value of derivatives	2,443	3,336
Foreign exchange losses		229
Finance costs	88,125	72,343
Net finance costs	82,338	71,801

(1) The Company is funding its share of the construction of new assets for its equity accounted investment and has recorded a $17.9 million receivable from related party as at December 31, 2011 (December 31, 2010: $11.5 million).

22. OPERATING SEGMENTS

The Company determines its reportable segments based on the nature of operations and includes four operating segments: Conventional Pipelines, Oil Sands & Heavy Oil, Midstream & Marketing and Gas Services.

Conventional Pipelines consists of the tariff based operations of pipelines and related facilities to deliver crude oil, condensate and NGL in Alberta and BC.

Oil Sands & Heavy Oil consists of the Syncrude, Horizon, Nipisi and Mitsue Pipelines, and the Cheecham Lateral. These pipelines and related facilities deliver synthetic crude oil produced from oil sands under long-term cost-of-service arrangements.

Midstream & Marketing consists of the Company's direct and indirect interest in a storage operation, its direct interests in terminalling, storage hub services under a mixture of short, medium and long-term contractual arrangements.

Gas Services consists of natural gas gathering and processing facilities, including three gas plants, twelve compressor stations and over 300 kilometres of gathering systems.

The financial results of the business segments is included below. Performance is measured based on results from operating activities, net of depreciation and amortization, as included in the internal management reports that are reviewed by the Company's CEO, CFO and COO. The segments results from operating activities, net of depreciation and amortization, is used to measure performance as management believes that such information is the most relevant in evaluating results of certain segments relative to other entities that operate within these industries.

Year Ended December 31, 2011

	Conventional Pipelines[1]	Oil Sands & Heavy Oil	Midstream & Marketing	Gas Services	Corporate	Total
Revenue from external customers:						
Pipeline transportation	296,190	134,874				431,064
Terminalling, storage and hub services			1,174,140			1,174,140
Gas Services				71,506		71,506
Total revenue	296,190	134,874	1,174,140	71,506		1,676,710
Cost of sales:						
Operations	119,093	43,986	8,833	22,407	(2,396)	191,923
Product purchases			1,072,048			1,072,048
Operating margin	177,097	90,888	93,259	49,099	2,396	412,739
Depreciation and amortization included in operations	41,595	12,786	3,710	9,921		68,012
Gross profit	135,502	78,102	89,549	39,178	2,396	344,727
Depreciation and amortization included in general and administrative					2,207	2,207
Other general and administrative	6,421	2,898	5,234	4,117	41,314	59,984
Other	1,018	(127)	2	6	530	1,429
Reportable segment results from operating activities	128,063	75,331	84,313	35,055	(41,655)	281,107
Net finance costs	(1,046)	1,729	(1,324)	999	81,980	82,338
Reportable segment earnings before tax	129,109	73,602	85,637	34,056	(123,635)	198,769
Share of profit of investments in equity accounted investees after tax			5,766			5,766
Reportable segment assets	878,949	991,309	430,138[2]	479,730	559,076	3,339,202
Capital expenditures	71,350	191,723	110,616	136,505	15,852	526,046
Reportable segment liabilities	340,481	95,762	24,358	72,032	1,844,952	2,377,585

(1) 4.8 percent of Conventional Pipelines revenue is under regulated tolling arrangements.
(2) Includes investments in equity accounted investees of $161,002.

Year Ended December 31, 2010

	Conventional Pipelines[1]	Oil Sands & Heavy Oil	Midstream & Marketing	Gas Services	Corporate	Total
Revenue from external customers:						
Pipeline transportation	261,617	118,420				380,037
Terminalling, storage and hub services			790,655			790,655
Gas Services				61,498		61,498
Total revenue	261,617	118,420	790,655	61,498		1,232,190
Cost of sales:						
Operations	92,561	40,212	4,673	18,372		155,818
Product purchases			735,223			735,223
Operating margin	169,056	78,208	50,759	43,126		341,149
Depreciation and amortization included in operations	28,430	22,748	2,073	8,401		61,652
Gross profit	140,626	55,460	48,686	34,725		279,497
Depreciation and amortization included in general and administrative					1,622	1,622
Other general and administrative	3,563	2,918	3,686	2,725	34,117	47,009
Other					658	658
Reportable segment results from operating activity	137,063	52,542	45,000	32,000	(36,397)	230,208
Net finance costs	5,705	950	(306)	1,172	64,280	71,801
Reportable segment earnings before tax	131,358	51,592	45,306	30,828	(100,677)	158,407
Share of profit investments in equity accounted investees after tax			9,103			9,103
Reportable segment assets	1,112,281	850,996	332,156[2]	338,009	223,406	2,856,848
Capital expenditures	28,750	115,610	22,020	33,540	1,955	201,875
Reportable segment liabilities	236,716	61,779	17,164	42,337	1,448,244	1,806,240

(1) 5.7 percent of Conventional Pipelines revenue is under regulated tolling arrangements.
(2) Includes investments in equity accounted investees of $190,739.

23. EARNINGS PER SHARE

Basic earnings per share

The calculation of basic earnings per share at December 31, 2011 was based on the profit attributable to common shareholders of $165.7 million (2010: $175.8 million) and a weighted average number of common shares outstanding of 167.4 million (2010: 163.2 million).

Diluted earnings per share

The calculation of diluted earnings per share at December 31, 2011 was based on profit attributable to common shareholders of $165.7 million (December 31, 2010: $178.8 million), and a weighted average number of common shares outstanding after adjustment for the effects of all dilutive potential common shares of 168.2 million (December 31, 2010: 167.5 million), calculated as follows:

Profit attributable to common shareholders

	Year Ended	
($ thousands)	**Dec. 31, 2011**	Dec. 31, 2010[1]
Profit attributable to common shareholders (basic)	165,666	175,830
Interest expense on convertible notes, net of tax		2,964
Profit attributable to common shareholders (diluted)	165,666	178,794

[1] Comparative amounts to October 1, 2010 are trust units.

Weighted average number of common shares

(In thousands of shares)	**2011**	2010
Issued common shares at January 1	166,877	158,589
Effect of share options exercised	556	1,185
Effect of conversion of convertible debentures		631
Effect of shares issued under dividend reinvestment plan		2,818
Weighted average number of common shares at December 31 (basic)	167,433	163,223
Dilutive effect of conversion of convertible debentures		3,662
Dilutive effect of share options on issue	742	579
Weighted average number of common shares at December 31 (diluted)	168,175	167,464
Basic earnings per share	0.99	1.08
Diluted earnings per share	0.99	1.07

At December 31, 2011, the effect of the conversion of the convertible debentures was excluded from the diluted earnings per share calculation as the impact was anti-dilutive. If the convertible debentures were included, an additional 8.1 million common shares would be added to the weighted average number of common shares and $13.8 million would be added to earnings, representing after tax interest expense of the convertible debentures.

The average market value of the Company's shares for purposes of calculating the dilutive effect of share options was based on quoted market prices for the period during which the options were outstanding.

24. CHANGES IN NON-CASH WORKING CAPITAL

($ thousands)	**2011**	2010
Accounts receivable, inventory and other	(28,840)	(29,331)
Accounts payable and accrued liabilities	10,091	20,166
Change in non-cash operating working capital	(18,749)	(9,165)

25. EMPLOYEE BENEFITS

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Registered defined benefit obligation	10,755	481	
Supplemental defined benefit obligation	5,092	4,382	4,110
Other accrued benefit obligations	1,104	1,149	1,211
Employee benefit obligations	16,951	6,012	5,321

The Company maintains a defined contribution plan and non-contributory defined benefit pension plans covering its employees. The defined benefit plans include a funded registered plan for all employees and an unfunded supplemental retirement plan for those employees affected by the Canada Revenue Agency maximum pension limits. The Company also has other accrued benefit obligations which include a non-contribution unfunded post employment extended health and dental plan provided to a few remaining retired employees. Benefits under the plans are based on the length of service and the annual average best three years of earnings during last ten years of service of the employee. Benefits paid out of the plans are not indexed. The Company measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The most recent actuarial valuation was at December 31, 2009.

Defined benefit obligations

	December 31, 2011		December 31, 2010		January 1, 2010	
($ thousands)	**Registered Plan**	**Supplemental Plan**	Registered Plan	Supplemental Plan	Registered Plan	Supplemental Plan
Present value of unfunded obligations		5,092		4,382		4,110
Present value of funded obligations	100,138		90,090		76,873	
Total present value of obligations	100,138	5,092	90,090	4,382	76,873	4,110
Fair value of plan assets	89,383		89,609		78,852	
Recognized asset (liability) for defined benefit obligations	(10,755)	(5,092)	(481)	(4,382)	1,979	(4,110)

The Company funds the defined benefit obligation plans in accordance with government regulations by contributing to trust funds administered by an independent trustee. The funds are invested primarily in equities and bonds. Defined benefit plan contributions totalled $8 million for each of the years ended December 31, 2011 and 2010.

The Company has determined that, in accordance with the terms and conditions of the defined benefit plans, and in accordance with statutory requirements of the plans, the present value of refunds or reductions in future contributions is not lower than the balance of the total fair value of the plan assets less the total present value of obligations. As such, no decrease in the defined benefit asset is necessary at December 31, 2011 and December 31, 2010.

Registered defined benefit pension plan assets comprise

(percentages)	**December 31, 2011**	December 31, 2010	January 1, 2010
Equity securities	64.1	64.6	65.5
Debt	30.8	34.4	33.3
Other	5.1	1.0	1.2
	100.0	100.0	100.0

Movement in the present value of the pension obligation

	Year Ended			
	December 31, 2011		December 31, 2010	
($ thousands)	**Registered Plan**	**Supplemental Plan**	Registered Plan	Supplemental Plan
Defined benefit obligations at January 1	90,090	4,382	76,873	4,110
Benefits paid by the plan	(6,108)		(5,323)	(66)
Current service costs and interest	9,944	402	9,356	451
Actuarial (gains) losses in other comprehensive income	6,212	308	9,184	(113)
Defined benefit obligations at December 31	100,138	5,092	90,090	4,382

Movement in the present value of registered defined benefit pension plan assets

($ thousands)	Year Ended December 31, 2011	December 31, 2010
Fair value of plan assets at January 1	89,609	78,852
Contributions paid into the plan	8,000	8,000
Benefits paid by the plan	(6,108)	(5,323)
Expected return on plan assets	5,521	5,112
Actuarial (losses) gains in other comprehensive income	(7,639)	2,968
Fair value of registered plan assets at December 31	89,383	89,609

Expense recognition in profit or loss

	Year Ended			
	December 31, 2011		December 31, 2010	
($ thousands)	**Registered Plan**	**Supplemental Plan**	Registered Plan	Supplemental Plan
Current service costs	4,780	149	4,123	172
Interest on obligation	5,164	253	5,233	279
Expected return on plan assets	(5,521)		(5,112)	
	4,423	402	4,244	451

The expense is recognized in the following line items in the statement of comprehensive income:

	Year Ended			
	December 31, 2011		December 31, 2010	
($ thousands)	**Registered Plan**	**Supplemental Plan**	Registered Plan	Supplemental Plan
Operating expense	2,771		2,945	
General and administrative expense	1,652	402	1,299	451
	4,423	402	4,244	451
Actual return on plan assets	(2,118)		8,080	

Actuarial gains and losses recognized in other comprehensive income

	Year Ended					
	Dec. 31, 2011			Dec. 31, 2010		
($ thousands)	**Registered Plan**	**Supplemental Plan**	**Total**	Registered Plan	Supplemental Plan	Total
Cumulative amount at January 1	4,662	(85)	4,577			
Recognized during the period after tax	10,388	231	10,619	4,662	(85)	4,577
Cumulative amount at December 31	15,050	146	15,196	4,662	(85)	4,577

Principal actuarial assumptions used as at December 31 (expressed as weighted averages):

	2011	2010
Discount rate	5.2%	5.6%
Expected long-term rate of return on plan assets	6.1%	6.3%
Future pension earning increases	4.0%	4.0%

Assumptions regarding future mortality are based on published statistics and mortality tables. The current longevities underlying the values of the liabilities in the defined plans are as follows:

(years)	**December 31, 2011**	December 31, 2010
Longevity at age 65 for current pensioners		
Males	19.7	19.6
Females	22.1	22.0
Longevity at age 65 for current member aged 45		
Males	21.2	21.1
Females	22.9	22.9

The calculation of the defined benefit obligation is sensitive to the discount rate, compensation increases, retirements and termination rates as set out above. An increase or decrease of the estimated discount rate of 5.2 percent by 100 basis points at December 31, 2011 is considered reasonably possible in the next financial year. A discount rate of 6.2 percent would increase the obligation by $18.9 million. A discount rate of 4.2 percent would decrease the obligation by $14.9 million.

The overall expected long-term rate of return on assets is 6.07 percent. The expected long-term rate of return is based on the portfolio as a whole and not on the sum of the returns on individual asset categories. The return is based exclusively on historical returns, without adjustments.

Historical information

	December 31, 2010		December 31, 2009	
($ thousands)	Registered Plan	Supplemental Plan	Registered Plan	Supplemental Plan
Present value of the defined benefit obligation	90,090	4,382	76,873	4,110
Fair value of plan assets	89,609		78,852	
Deficit/(surplus) in the plan	(481)	(4,382)	1,979	(4,110)
Experience adjustments arising on plan liabilities	886	356	1,402	(14)
Experience adjustments arising on plan assets	(2,968)		(7,417)	

	December 31, 2008		December 31, 2007	
($ thousands)	Registered Plan	Supplemental Plan	Registered Plan	Supplemental Plan
Present value of the defined benefit obligation	58,359	3,000	73,065	3,438
Fair value of plan assets	60,682		72,725	
Deficit/(surplus) in the plan	2,323	(3,000)	(340)	(3,438)
Experience adjustments arising on plan liabilities		211	(637)	338
Experience adjustments arising on plan assets	17,702		4,290	

The Company expects $10 million in contributions to be paid to its defined benefit plans in 2012.

26. SHARE-BASED PAYMENTS

At December 31, 2011 the Company has the following share-based payment arrangements:

Share option plan (cash and equity settled)

The Company has a share option plan under which directors, officers and employees are eligible to receive options to purchase shares in the Company. Directors and Officers are not eligible to receive options under Pembina's option plan which was approved in 2011. On October 1, 2010, the Pembina converted from a Trust to a Corporation. All trust units previously issued under the trust unit option plan transferred directly to the holders as share options under the share option plan, under the same terms. The trust unit option plan up until the date of conversion was considered to be a cash-settled share-based payment due to the redeemable feature of the underlying trust units.

Long-term share unit award incentive (cash-settled) plan

In 2005, the Company established a long-term share unit award incentive plan. Under the share-based compensation plan, awards of restricted (RSU) and performance (PSU) shares are made to officers, non-officers and directors. The plan results in participants receiving cash compensation based on the value of the underlying notional shares granted under the plan. Payments are based on a trading value of the shares plus notional accrued dividends and performance of the Company.

Terms and conditions of share option plan and share unit award incentive plan

The terms and conditions relating to the grants of the share option program and the long-term share unit award incentive plans are listed in the tables below.

Vesting Conditions:

(a) One third vest on the grant date, one third vest on the first anniversary of the grant date, and one third vest on the second anniversary of the grant date.
(b) One third vest on the first anniversary of the grant date, one third vest on the second anniversary of the grant date, and one third vest on the third anniversary of the grant date.
(c) One third vest on the first anniversary of the grant date, one third vest on the second anniversary of the grant date, and one third vest on the third anniversary of the grant date.
(d) Vest one third immediately on the grant date, one third on the second anniversary of the grant date and one third on the third anniversary of the grant date.
(e) Vest on the third anniversary of the grant date. Actual PSUs awarded is based on the trading value of the shares and performance of the Company.

Grant date share options granted to employees	Number of options in thousands	Vesting conditions	Contractual life of options
April 27, 2005	729	a	7 years
November 30, 2006	3,411	a	7 years
June 29, 2007	278	a	7 years
October 1, 2007	40	a	7 years
January 1, 2008	89	a	7 years
April 11, 2008	150	a	7 years
July 1, 2008	167	a	7 years
October 1, 2008	195	a	7 years
January 1, 2009	158	a	7 years
April 1, 2009	230	a	7 years
July 1, 2009	182	a	7 years
October 1, 2009	118	a	7 years
January 1, 2010	100	a	7 years
September 15, 2010	854	b	7 years
August 3, 2011	1,052	b	7 years
October 1, 2011	48	b	7 years
	7,801		

Long-term share unit award incentive plan[1]

Grant date Restricted Share Units ("RSU") to Officers Non-Officers[2] and Directors	Number of units in thousands	Vesting conditions	Contractual life of options
January 1, 2009	278	c	3 years
January 1, 2010	207	c	3 years
January 1, 2011	185	c	3 years
	670		

Grant date Performance Share Units ("PSU") to Officers Non-Officers[2] and Directors	Number of units in thousands	Vesting conditions	Contractual life of options
December 31, 2009	132	d	2 years
January 1, 2010	313	e	3 years
January 1, 2011	284	e	3 years
	729		

[1] Distribution Units are granted in addition to RSU and PSU grants based on notional accrued dividends from RSU and PSU granted but not paid.
[2] Non-Officers defined as senior selected positions within the Company.

Disclosure of share option plan

The number and weighted average exercise prices of share options are as follows:

	Number of Options[1]	Weighted Average Exercise Price
Outstanding at January 1, 2010	3,877,417	15.02
Granted	954,380	19.01
Exercised	(1,967,576)	14.93
Forfeited	(104,962)	16.40
Outstanding as at December 31, 2010	2,759,259	16.43
Granted	1,100,800	25.29
Exercised	(1,023,916)	15.48
Forfeited	(161,763)	19.75
Outstanding as at December 31, 2011	2,674,380	20.24

[1] Comparative amounts to October 1, 2010 are trust unit options.

As of December 31, 2011, the following options are outstanding:

Exercise Price *(dollars)*	Number outstanding at December 31, 2011	Options Exercisable	Weighted average remaining life (years)
$13.85	43,526	43,526	0.32
$14.74	578,106	578,106	1.91
$15.57	11,000	11,000	2.49
$16.73	5,500	5,500	2.75
$17.08	6,600	6,600	3.00
$16.46	58,500	58,500	3.27
$18.06	44,000	44,000	3.50
$16.78	24,500	24,500	3.75
$14.84	17,500	17,500	4.00
$14.18	19,364	19,364	4.25
$14.91	54,666	54,666	4.50
$15.35	13,334	13,334	4.75
$17.62	45,382	15,551	5.00
$19.17	685,802	199,299	5.71
$25.28	1,018,440		6.59
$25.44	48,160		6.75

The weighted average share price at the date of exercise for share options exercised in the year ending December 31, 2011 was $24.64 (December 31, 2010: $18.84).

Inputs for measurement of grant date fair values

At January 1, 2010, the trust unit option plan was considered a cash settled share-based payment and the fair value of the trust unit options was recognized as a liability and remeasured at each reporting period until the conversion to a Corporation on October 1, 2010, at which time the plan was converted to a stock option plan, which is considered to be an equity settled share-based payment. The grant date fair value of the options was recalculated using the Black Scholes formula at October 1, 2010 and recognized retroactively with the fair value of the options recognized in share capital and contributed surplus. As a result of the revaluation on conversion to a Corporation on October 1, 2010, the fair value of unexercised options decreased from $8.9 million to $2.0 million, with the difference reported as an increase in Share Capital.

Expected volatility is estimated by considering historic average share price volatility. The weighted average inputs used in the measurement of the fair values at grant date of share options are the following:

Share options granted during the period

	Options Granted During The Period		Options Revalued at Corporate Conversion
(dollars)	**December 31, 2011**	December 31, 2010	October 1, 2010
Weighted average			
Fair value at grant date	$2.72	$1.57	$1.46
Share price at grant date	$25.72	$19.19	$17.33
Exercise price	$25.29	$19.01	$17.21
Expected volatility	24.7%	26.9%	30.8%
Expected option life (years)	3.67	2.67	2.71
Expected dividends per option	$1.56	$1.56	$1.56
Expected forfeitures	7.0%	4.9%	3.4%
Risk-free interest rate (based on government bonds)	1.6%	1.7%	1.7%

Disclosure of long-term share unit award incentive plan

The long-term share unit award incentive plan was valued using the reporting date market price of the Company's shares of $29.66 (December 31, 2010: $21.60). Actual payment may differ from amount valued based on market price and company performance.

Long-term share unit award incentive units granted during the period

	December 31, 2011	December 31, 2010[1]
Number of share units granted	469,253	520,154

[1] Comparative amounts to October 1, 2010 are trust units.

Employee expenses

($ thousands)	**December 31, 2011**	December 31, 2010[1]
Unit option plan, cash settled		6,066
Share option plan, equity settled	1,097	194
Long-term share unit award incentive plan	17,554	8,610
Total expense recognized as employee costs	18,651	14,870
Total carrying amount of liabilities for cash settled arrangements	22,971	13,535
Total intrinsic value of liability for vested benefits	8,911	8,282

[1] Comparative amounts to October 1, 2010 are trust units.

27. CONTINGENCIES

Contingent assets

On July 19, 2011 Pembina discovered a spill between 800 to 1,000 barrels of light sweet crude on its Moosehorn 8 inch gathering pipeline forming part of the Swan Hills Pipeline system. An initial claim related to this spill has been filed under Pembina's pollution liability policy but the final claim is yet to be defined as the amount is not yet fully quantified as work is still in progress to remediate the impacted sites. Once work is completed and a final cost is known, a final insurance claim will be made to seek recovery of all costs related to pollution liability. Not all of the damage resulting from this spill will be recoverable as Pembina only insures for pollution liability and clean-up, not for the damage to the pipe itself. There will be a $2.0 million deductible. At December 31, 2011 a $20 million provision has been recognized with an offsetting $15.6 million receivable.

Contingent liabilities

On May 7, 2009, a company sued Alberta Oil Sands Pipeline Ltd., a subsidiary of Pembina, among others, in relation to the recovery of cost overruns associated with the construction of the Horizon Pipeline Project in the amount of $6.8 million. Pembina has completed its Affidavit of Records and examinations for discovery are currently underway. Pembina has recognized a provision based on the best estimate of the settlement as of the reporting date.

The Company did not have any litigation settlements during the years ending December 31, 2011 and 2010.

28. FINANCIAL RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Economic hedge

The Company has entered into derivative financial instruments to limit the exposures to changes in interest rates, costs of power and certain commodity prices. Hedge accounting has not been applied because the criteria for hedge accounting are not met, however the Company still considers that there is an economic hedge which limits the exposure to fluctuations in expenses.

Financial Risk

The Company has exposure to credit risk, liquidity risk and market risk. The Company's Board of Directors has the overall responsibility for the oversight of these risks and reviews the Company's policies on an ongoing basis to ensure that these risks are appropriately managed. The Company's Audit Committee oversees how management monitors compliance with the Company's risk management policies and procedures and reviews the adequacy of this risk framework in relation to the risks faced by the Company. The Company's Risk Management function assists in managing these risks. The Company's primary risk management objective is to protect capital resources, earnings and cash flow.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer, partner or counterparty to a financial instrument fails to meet its contractual obligations and arises primarily from the Company's cash and cash equivalents and receivables and from counterparties to its derivative financial instruments. The carrying amount of the financial assets represents the maximum credit exposure to the Company. The maximum exposure to credit risk at the reporting date was:

	Carrying Amount		
($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Cash and cash equivalents		125,397	53,927
Trade and other receivables	159,081	105,474	83,244
Financial assets designated at fair value through profit or loss:			
Power derivatives	4,183	879	336
Commodity derivatives	2,267	4,561	998
	165,531	236,311	138,505

The Company manages credit risk for its cash and cash equivalents by maintaining bank accounts with Schedule 1 banks. The Company has minimal credit risk related to its receivables as a majority of these amounts are with large established customers in the oil and gas industry and are subject to the terms of the Company's shipping rules and regulations or pursuant to contracts. The rules and regulations permit the Company to receive and hold credit assurance against a counterparty to cover current and aged receivables when warranted. Balances are payable the 25th day of the following month. This date coincides with the date on which oil and gas companies receive payment from industry partners and customers. Historically, Pembina has collected its receivables in full with an excess of approximately 80 percent collected on the due date. Pembina also maintains lien rights on the oil and NGL's that are in the Company's custody during the transportation of such products on the pipeline as well as the right to offset for single shipper operations. Therefore, the risk of non-collection is considered to be low and no impairment of receivables has been made.

Additionally, credit risk is mitigated through established credit management techniques, including conducting comprehensive financial and sector assessments for all new shippers on the Company's systems and regular reviews of the credit status of current shippers to establish and monitor the counterparty's creditworthiness, to set exposure limits and to obtain financial assurances such as letters of credit and guarantees when warranted. Letters of credit and guarantees mitigate the credit risk on $7.8 million (December 31, 2010: $6.2 million) of the receivables balance. The Company's review includes external ratings for customers, where available, and in other cases, detailed financial assessments and reviews which generates a credit rating based on financial ratios. Credit limits are established for each customer representing the maximum open amount and an associated limit approval authority matrix has been approved by the Risk Management Committee. These limits are reviewed on an ongoing basis.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The following are the contractual maturities of financial liabilities, including estimated interest payments and excluding the impact of netting agreements.

			Outstanding balances due by period				
December 31, 2011 *($ thousands)*	Carrying Amount	Expected Cash Flows	6 Months or Less	6 – 12 Months	1 – 2 Years	2 – 5 Years	More Than 5 Years
Non-derivative financial liabilities							
Bank overdraft	676	676	676				
Trade payables and accrued liabilities	155,926	155,926	155,926				
Unsecured notes and credit facilities	1,272,838	1,663,644	27,120	340,285	350,445	117,494	828,300
Senior secured notes	57,499	70,909	6,257	6,257	25,027	33,368	
Finance lease liabilities	5,650	7,742	1,273	1,273	1,942	3,254	
Convertible debentures	289,365	299,780					299,780
Dividends payable	21,828	21,828	21,828				
Derivative financial liabilities							
Interest rate derivatives	17,539	18,460	2,385	2,385	3,670	6,438	3,582

It is not expected that the cash flows included in the maturity analysis could occur significantly earlier, or at significantly different amounts.

			Outstanding balances due by period				
December 31, 2010 *($ thousands)*	Carrying Amount	Expected Cash Flows	6 Months or Less	6 – 12 Months	1 – 2 Years	2 – 5 Years	More Than 5 Years
Non-derivative financial liabilities							
Trade payables and accrued liabilities	99,023	99,023	99,023				
Unsecured notes and credit facilities	950,207	1,269,467	21,002	21,040	324,085	337,832	565,508
Senior secured notes	65,395	83,422	6,257	6,257	25,026	37,540	8,342
Finance lease liabilities	4,555	5,315	1,030	1,030	2,567	688	
Convertible debentures	288,635	300,000					300,000
Dividends payable	21,694	21,694	21,694				
Derivative financial liabilities							
Interest rate derivatives	9,922	10,788	1,260	1,260	2,520	3,501	2,247
Power derivatives	440	440	88	88	186	78	
Commodity derivatives	3,727	3,727	3,727				

The Company's approach to managing liquidity risk is to ensure funds and credit facilities are available to meet its short term obligations. Management monitors daily cash positions and performs cash forecasts weekly to determine cash requirements. On a monthly basis, Management typically forecasts cash flows for a period of 12 months to identify financing requirements. These financing requirements are then addressed through a combination of credit facilities and through access to capital markets if required.

Market Risk

Market risk is the risk that the changes in market prices, such as interest rates, power and commodity prices affect the Company's earnings and the value of financial instruments it holds.

The Company uses derivative financial instruments to manage exposure to power costs, interest rates, and crude oil and NGL prices. The Company does not trade financial instruments for speculative purposes.

Contracts used to manage market risk generally consist of swap contracts. These contracts consist of interest rate swaps and power swaps to manage the potential increase or decrease in the price of non-transmission power charges and interest expense on floating rate debt instruments. The Company, from time to time, enters into commodity derivative transactions, offsetting physical transactions with financial transactions. All swaps are reported in current period earnings.

Currency risk

The Company's only foreign currency transactions are purchases resulting in US dollar trade payables. The US dollar trade payables at December 31, 2011 are Nil (December 31, 2010 - $0.3 million USD, January 1, 2010 - Nil) so exposure to currency risk is limited.

Interest rate risk

At the reporting date, the interest rate profile of the Company's interest-bearing financial instruments was:

	Carrying Amounts	
($ thousands)	**December 31, 2011**	December 31, 2010
Fixed rate instruments		
Financial assets		
Financial liabilities	(1,524,758)	(1,282,959)
	(1,524,758)	(1,282,959)
Variable rate instruments		
Financial assets		82,083
Financial liabilities	(119,465)	(45,556)
	(119,465)	36,527

Fair value sensitivity analysis for fixed rate instruments

The Company does not account for any fixed rate financial assets and liabilities at fair value through profit or loss, and the Company does not designate derivatives (interest rate swaps) as hedging instruments under a fair value hedge accounting model; therefore a change in interest rates at the reporting date would not affect profit or loss.

Cash flow sensitivity analysis for variable rate instruments

A change of 100 basis points in interest rates at the reporting date would have increased (decreased) profit or loss by the amounts shown below. This analysis assumes that all other variables remain constant.

	December 31, 2011		December 31, 2010	
($ thousands)	100 bp increase	100 bp decrease	100 bp increase	100 bp decrease
Variable rate instruments	3,149	(3,149)	2,462	(2,462)
Interest rate swap	(2,000)	2,000	(2,000)	2,000
Profit or loss sensitivity (net)	1,149	(1,149)	462	(462)

Cost of power risk

The Company is exposed to changes in the cost of power. At December 31, 2011, the Company has fixed the price of 15 megawatts ("MW") of non-transmission power charges by way of price swap contracts which expired at December 31, 2011. For 2012, Pembina has fixed the price of 20 MW and from 2013 - 2015 Pembina has fixed the price of 10 MW. The power swap fixes the price for power consumption each day on the Conventional Pipeline Systems. No price swap contracts have been entered into to cover the power costs on Pembina's Oil Sands & Heavy Oil infrastructure systems. Revenue on these pipelines is contracted to recover operating costs and therefore, Pembina's net operating income from Oil Sands & Heavy Oil is not impacted by fluctuations in power costs. A change of $5 MW/h in the Alberta pool power price would have increased (decreased) profit or loss by the amounts shown below. This analysis assumes that all other variables remain constant.

($ millions)	December 31, 2011 $5 MW/h change	December 31, 2010 $5MW/h change
Operating power costs	0.8	0.7
Realized gain on power hedge	(0.7)	(0.7)
Profit or loss sensitivity (net)	0.1	

Fair values

The fair values of financial assets and liabilities, together with the carrying amounts shown in the statement of financial position, are as follows:

	December 31, 2011		December 31, 2010	
($ thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Financial assets carried at fair value				
Commodity derivatives	2,267	2,267	4,561	4,561
Power derivatives	4,183	4,183	879	879
	6,450	6,450	5,440	5,440
Financial assets carried at amortized cost				
Cash and cash equivalents			125,397	125,397
Trade and other receivables	159,081	159,081	105,474	105,474
	159,081	159,081	230,871	230,871
Financial liabilities carried at fair value				
Interest rate derivatives	17,539	17,539	9,922	9,922
Power derivatives			440	440
Commodity derivatives			3,727	3,727
	17,539	17,539	14,089	14,089
Financial liabilities carried at amortized cost				
Bank overdraft	676	676		
Trade payables and accrued liabilities	155,926	155,926	99,023	99,023
Finance lease liabilities	5,650	5,948	4,555	4,970
Dividends payable	21,828	21,828	21,694	21,694
Unsecured notes and credit facilities	1,272,838	1,391,895	950,207	1,044,497
Senior secured notes	57,499	65,567	65,395	74,276
Convertible debentures	289,365	326,760	288,635	303,750
	1,803,782	1,968,600	1,429,509	1,548,210

The basis for determining fair values is disclosed in note 4.

Interest rates used for determining fair value

The interest rates used to discount estimated cost flows, when applicable, are based on the government yield curve at the reporting date plus and adequate credit spread, and were as follows:

	December 31, 2011	December 31, 2010
Derivatives	1.13% - 1.8%	2.08% - 3.1%
Loans and borrowings	2.175% - 4.25%	2.625% - 4.155%
Leases	4.8%	5.0%

Fair value of power derivatives are based on market rates reflecting forward curves.

Fair value hierarchy

The fair value of financial instruments carried at fair value is classified according to the following hierarchy based on the amount of observable inputs used to value the instruments.

Level 1: Unadjusted quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Pembina does not use Level 1 inputs for any of its fair value measurements.

Level 2: Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices). Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value, volatility factors and broker quotations, which can be substantially observed or corroborated in the marketplace. Instruments in this category include non-exchange traded derivatives such as over-the-counter physical forwards and options, including those that have prices similar to quoted market prices. Pembina obtains quoted market prices for commodities, future power contracts and interest rates. Information sources include banks, Natural Gas Exchange (NGX), ICAP Capital Markets Inc. (ICAP), Tullett Prebon Information Inc. (Prebon), independent price publications and over-the-counter broker quotes.

Level 3: Valuations in this level require the most significant judgments and consist primarily of unobservable or non-market based inputs. Level 3 inputs include longer-term transactions, transactions in less active markets or transactions at locations for which pricing information is not available. In these instances, internally developed methodologies are used to determine fair value, which primarily includes extrapolation of observable future prices to similar locations, similar instruments or later time periods. Pembina does not use Level 3 inputs for any of its fair value measurements.

The following table includes our financial instruments that are carried at fair value for our trading and non-trading activities as at December 31, 2011 and December 31, 2010. Financial instruments are classified in the fair value hierarchy in their entirety based on the least observable input that is significant to the fair value measurement. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect placement within the fair value hierarchy levels.

	December 31, 2011			December 31, 2010		
($ thousands)	**Level 1**	**Level 2**	**Level 3**	Level 1	Level 2	Level 3
Interest rate derivatives		(17,539)			(9,922)	
Power derivatives		4,183			439	
Commodity derivatives		2,267			834	
		(11,089)			(8,649)	

29. OPERATING LEASES

Leases as lessee

Operating lease rentals are payable as follows:

($ thousands)	**December 31, 2011**	December 31, 2010	January 1, 2010
Less than 1 year	6,237	3,194	2,795
Between 1 and 5 years	20,021	4,998	7,404
More than 5 years	40,494		18
	66,752	8,192	10,217

The Company leases a number of offices and warehouses under operating leases. The leases run for a period of one to sixteen years, with an option to renew the lease after that date. The Company has sublet office space for 2012 and 2013. The Company has contracted sub-lease payments of $1.4 million in 2012 and $1.1 million in 2013.

During the year ended December 31, 2011 an amount of $3.8 million was recognized as an expense in profit or loss in respect of operating leases (December 31, 2010: $2.6 million).

30. CAPITAL COMMITMENTS

During the period ended December 31, 2011 the Company entered into agreements that will require future capital expenditures. These agreements have resulted in a commitment to purchase property, plant and equipment of $364.3 million (December 31, 2010: $345.8 million).

31. CAPITAL MANAGEMENT

The Company's objective when managing capital is to safeguard the Company's ability to provide a stable stream of dividends to shareholders that is sustainable over the long-term. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and risk characteristics of its underlying asset base and based on requirements arising from significant capital development activities. Pembina manages and monitors its capital structure and short-term financing requirements using Non-GAAP measures; the ratios of debt to EBITDA, debt to Enterprise Value (market value of common shares and convertible debentures) and debt to equity. The metrics are used to measure the Company's overall debt position and measure the strength of the Company's balance sheet. The Company remains satisfied that the leverage currently employed in the Company's capital structure is sufficient and appropriate given the characteristics and operations of the underlying asset base. The Company, upon approval from its Board of Directors, will balance its overall capital structure through new equity or debt issuances as required.

The Company maintains a conservative capital structure that allows it to finance its day-to-day cash requirements through its operations, without requiring external sources of capital. The Company funds its operating commitments, short-term capital spending as well as its dividends to shareholders through this cash flow, while new borrowing and equity issuances are reserved for the support of specific significant development activities. The capital structure of the Company consists of shareholder's equity plus long-term liabilities. Long-term debt is comprised of bank credit facilities, senior secured and unsecured notes, finance lease obligations and convertible debentures.

Pembina is subject to certain financial covenants in its credit facility agreements and is in compliance with all financial covenants as of December 31, 2011.

Note 15 of these financial statements demonstrates the change in Share Capital for the year ended December 31, 2011.

32. GROUP ENTITIES

Significant subsidiaries

	Ownership interest		
(percentages)	**December 31, 2011**	December 31, 2010	January 1, 2010
Pembina Pipeline	**100**	100	100
Pembina Gas Services Limited Partnership	**100**	100	100
Pembina Oil Sands Pipeline LP	**100**	100	100
Pembina Midstream Limited Partnership	**100**	100	100
Pembina North Limited Partnership	**100**	100	100
Pembina West Limited Partnership	**100**	100	100

33. RELATED PARTIES

All transactions with related parties were made on terms equivalent to those that prevail in arm's length transactions.

Investments in equity accounted investees

Officers of Pembina Pipeline Corporation, the ultimate controlling party, are Directors of Fort Saskatchewan Ethylene Storage Corporation ("FSESC"), the parent of Fort Saskatchewan Ethylene Storage Limited Partnership ("FSESLP"). FSESLP and FSESC are both recognized as investments in joint ventures under the equity method on Pembina's financial statements. Results from operating activities are recorded as Share of Profit from Equity Accounted Investees on Pembina's Statement of Comprehensive Income, representing a 50 percent interest in the joint ventures.

($ thousands)			Transaction Value Year Ended		Balance Outstanding As At		
Related Party	Transaction	Note	Dec. 31, 2011	Dec. 31, 2010	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
FSESLP[(1)]	Interest revenue		876	168			
	Loan Receivable				17,903	11,454	

(1) A promissory note, dated July 30, 2010 from FSESLP, payable on demand, bears interest at 6.0 percent.

Key management personnel and director compensation

Key management consists of the Company's directors and certain key officers.

Compensation

In addition to short term employee benefits including salaries, director fees and bonuses, the Company also provides key management personnel with share-based compensation, contributes to post employment pension plans and provides car allowances, parking and business club memberships.

Key Management personnel compensation comprised:

($ thousands)	**Year Ended December 31, 2011**	Year Ended December 31, 2010
Short term employee benefits	2,802	2,763
Post-employment benefits	207	182
Share-based compensation	6,150	3,596
Other compensation	112	109
Total Compensation of Key Management	9,271	6,650

Transactions

Key management personnel and directors of the Company control 0.8 percent of the voting common shares of the Company. Certain directors and key management personnel also hold Pembina convertible debentures. Dividend and interest payments received for the common shares and debentures held are commensurate with other non-related holders of those instruments.

Certain officers are subject to employment agreements in the event of termination without just cause or change of control.

Post employment benefit plans

Pembina has significant influence over the pension plans for the benefit of their respective employees.

Transactions

($ thousands)		Transaction Value Year Ended		Balance Outstanding As At		
Post-employment benefit plan	Transaction	**Dec. 31, 2011**	Dec. 31, 2010	**Dec. 31, 2011**	Dec. 31, 2010	Jan. 1, 2010
Defined benefit plan	Funding	8,000	8,000			

34. SUBSEQUENT EVENTS

On January 16, 2012 Pembina and Provident Energy Ltd ("Provident") announced that they entered into an agreement (the "Arrangement Agreement") for Pembina to acquire all of the issued and outstanding common shares of Provident (the "Provident Shares") by way of a plan of arrangement under the Business Corporations Act (Alberta) (the "Arrangement") to create an integrated company that will be a leading player in the North American energy infrastructure sector. Upon the successful completion of this transaction Pembina intends to increase its monthly dividend rate from $0.13 per share per month (or $1.56 annualized) to $0.135 per share per month (or $1.62 annualized) representing a 3.8 percent increase and reflecting management's confidence in the significant operational and financial strength of the combined entity going forward.

Transaction Description

Under the terms of the Arrangement Agreement, Provident shareholders will receive 0.425 of a Pembina share for each Provident share held (the "Provident Exchange Ratio"). Based on the January 13, 2012 TSX closing share price of Pembina of $27.90, the Provident Exchange Ratio represents a premium of 24.7 percent to Provident's closing TSX share price on January 13, 2012 of $9.51. Based on the 20-day weighted average TSX share price of Pembina of $29.11, the Provident Exchange Ratio represents a premium of 26.2 percent to Provident's 20-day weighted average TSX share price of $9.80. The proposed transaction is expected to immediately increase Pembina's cash flow per share, increase its dividends per share and reduce its dividend payout ratio. After completion of the proposed transaction the combined assets and employees will operate under the Pembina name and will be led by a combination of Pembina's and Provident's executive team.

Under the Arrangement Agreement, Pembina will also assume all of the rights and obligations of Provident relating to: (i) the 5.75% convertible unsecured subordinated debentures of Provident maturing December 31, 2017, and (ii) the 5.75% convertible unsecured subordinated debentures of Provident maturing December 31, 2018 (collectively, the "Provident Debentures"). The conversion price of each class of Provident Debentures will be adjusted pursuant to the terms of the trust indenture governing the Provident Debentures based on the Provident Exchange Ratio. Following closing of the transaction, Pembina intends to make an offer for the Provident Debentures at 100 percent of their principal values plus accrued and unpaid interest. The repurchase offer will be made within 30 days of closing of the proposed transaction. Should a holder of the Provident Debentures elect not to accept the repurchase offer, the debentures will mature as originally set out in their respective indentures. Holders who convert their Provident Debentures following completion of the Arrangement will receive common shares of Pembina. In addition, Provident will immediately suspend its premium dividend reinvestment plan and dividend reinvestment plan.

The Arrangement is subject to the approval of Provident shareholders, Pembina shareholders and the Court of Queen's Bench of Alberta. Further information regarding the proposed transaction will be contained in a joint information circular that Pembina and Provident will prepare, file and mail in due course to their respective shareholders in connection with the special meetings of shareholders of each Pembina and Provident, which are each scheduled to take place on March 27, 2012. In addition to shareholder and court approvals, the proposed transaction is subject to applicable regulatory approvals and the satisfaction of certain other closing conditions customary in transactions of this nature, including compliance with the Competition Act (Canada) and the acceptance of the TSX. If approved by shareholders, closing of the transaction is expected to occur as soon as possible thereafter subject to regulatory approval.

35. EXPLANATION OF TRANSITION TO IFRS

As stated in note 2(a), these are the Company's first annual consolidated financial statements prepared in accordance with IFRS.

The accounting policies set out in note 3 have been applied in preparing the consolidated financial statements for the year ended December 31, 2011 and the comparative information presented in these consolidated financial statements for the year ended December 31, 2010.

In preparing its opening IFRS statement of financial position, the Company has adjusted amounts reported previously in financial statements prepared in accordance with previous Canadian GAAP. An explanation of how the transition from previous Canadian GAAP to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables and the notes that accompany the tables.

Reconciliation of equity at January 1, 2010

($ thousands)	Note	Previous Canadian GAAP	Effect of transition to IFRSs	Reclass	IFRS
		January 1, 2010			
Current assets					
Cash and cash equivalents		53,927			53,927
Trade and other receivables		83,244			83,244
Derivative financial instruments				1,334	1,334
Inventory		18,998			18,998
		156,169		1,334	157,503
Non - current assets					
Property, plant and equipment	a,d,e	2,045,917	(80,234)		1,965,683
Intangible assets	a	361,242	(115,942)		245,300
Employee benefits	c	17,797	(19,928)	4,110	1,979
Investments in equity accounted investees	a		196,330		196,330
		2,424,956	(19,774)	4,110	2,409,292
		2,581,125	(19,774)	5,444	2,566,795
Current liabilities					
Trade payable and accrued liabilities	b,g	57,997	1,453	(1,211)	58,239
Dividends payable		20,616			20,616
Loans and borrowings	e	157,423	1,901		159,324
Derivative financial instruments				2,153	2,153
Convertible debentures		36,640			36,640
		272,676	3,354	942	276,972
Non-current liabilities					
Loans and borrowings	e	973,522	2,560		976,082
Derivative financial instruments	f	5,481	150	(819)	4,812
Employee benefits				5,321	5,321
Share-based payments	b		12,893		12,893
Provisions	d	104,204	112,899		217,103
Deferred tax liabilities	h	95,870	(20,031)		75,839
		1,451,753	111,825	5,444	1,569,022
Equity					
Share capital	b	1,660,795	(2,992)		1,657,803
Deficit	i	(527,082)	(132,948)		(660,030)
Accumulated other comprehensive income	f	(4,341)	4,341		
		1,129,372	(131,599)		997,773
		2,581,125	(19,774)	5,444	2,566,795

Reconciliation of equity at December 31, 2010

($ thousands)	Note	Previous Canadian GAAP	Effect of transition to IFRS	Reclass	IFRS
		December 31, 2010			
Current assets					
Cash and cash equivalents		125,397			125,397
Trade and other receivables		105,474			105,474
Derivative financial instruments				5,199	5,199
Inventory		26,099			26,099
		256,970		5,199	262,169
Non-current assets					
Property, plant and equipment	a,d,e	2,172,450	(13,353)		2,159,097
Intangible assets	a	356,793	(112,191)		244,602
Employee benefits	c	20,195	(25,058)	4,863	
Investments in equity accounted investees	a		190,739		190,739
Derivative financial instruments				241	241
		2,549,438	40,137	5,104	2,594,679
		2,806,408	40,137	10,303	2,856,848
Current liabilities					
Trade payable and accrued liabilities	b,g	99,228	944	(1,149)	99,023
Dividends payable		21,694			21,694
Loans and borrowings	e	7,981	2,074		10,055
Derivative financial instruments				6,384	6,384
		128,903	3,018	5,235	137,156
Non-current liabilities					
Loans and borrowings	e	1,007,620	2,482		1,010,102
Convertible debentures		288,635			288,635
Derivative financial instruments	f	8,647		(944)	7,703
Employee benefits				6,012	6,012
Share-based payments	b		5,252		5,252
Provisions	d	101,437	180,257		281,694
Deferred tax liabilities	h	91,006	(21,320)		69,686
		1,626,248	169,689	10,303	1,806,240
Equity					
Share capital	b,f	1,782,804	11,732		1,794,536
Deficit	i	(595,533)	(143,818)		(739,351)
Accumulated other comprehensive income	c,f	(7,111)	2,534		(4,577)
		1,180,160	(129,552)		1,050,608
		2,806,408	40,137	10,303	2,856,848

Reconciliation of comprehensive income for the year ended December 31, 2010.

($ thousands)	Note	Canadian GAAP	Effect of transition to IFRS	Reclass	IFRS
Revenues:					
Conventional pipelines		261,617			261,617
Oil sands and heavy oil		118,420			118,420
Midstream & marketing	a	813,567	(22,912)		790,655
Gas services		61,498			61,498
		1,255,102	(22,912)		1,232,190
Cost of sales					
Operations	a,b,c,d,e	160,147	(1,485)	(2,844)	155,818
Product purchases		735,223			735,223
Depreciation and amortization	a,e	66,891	(3,617)	(1,622)	61,652
		962,261	(5,102)	(4,466)	952,693
Gross profit		292,841	(17,810)	4,466	279,497
G&A expenses	b,c,g	44,086	79	4,466	48,631
Other expense (income)		(189)		847	658
Accretion	d	7,068	1,304	(8,372)	
		50,965	1,383	(3,059)	49,289
Results from operating activities		241,876	(19,193)	7,525	230,208
Net finance costs	e,f	60,168	4,108	7,525	71,801
Earnings before income tax		181,708	(23,301)		158,407
Share of (profit) of investments in equity accounted investees, net of tax	a		(9,103)		(9,103)
Income tax recovery	a,b,c, d,e,f,h	(4,992)	(3,328)		(8,320)
Earnings for the period		186,700	(10,870)		175,830
Other comprehensive income, net of income tax					
Defined benefit plan actuarial losses	c		(4,577)		(4,577)
Net change in fair value of cash flow hedges	f	(2,770)	2,770		
Total comprehensive income for the period		183,930	(12,677)		171,253
Earnings per share/unit					
Basic earnings per share/unit *(dollars)*		1.14			1.08
Diluted earnings per share/unit *(dollars)*		1.14			1.07

IFRS 1 elections and exemptions

IFRS 1 allows first-time adopters certain exemptions from retrospective application of certain IFRS. The Company applied the following exemptions from retrospective application of certain IFRS.

Exemptions that are not applicable, or without an accounting policy change or no significant impact, have not been listed.

a. Business combinations

IFRS 3 *Business Combinations* requires entities to retrospectively adjust business combinations that occurred prior to January 1, 2010. The transitional exemption allows entities to apply IFRS 3 prospectively. Pembina has elected the exemption and did not restate past business combinations occurring prior to January 1, 2010.

b. Employee benefits (actuarial gains and losses)

Pembina has elected this exemption which allows the recognition of Canadian GAAP cumulative unrecognized actuarial losses as at December 31, 2009 in deficit thereby avoiding retrospective restatement of the cumulative actuarial gains and losses at December 31, 2009. Going forward, Pembina will recognize future actuarial gains and losses in other comprehensive income.

c. Decommissioning liabilities included in the cost of PP&E

The International Financial Reporting Interpretations Committee (IFRIC) 1: *Changes in Existing Decommissioning, Restoration and Similar Liabilities* requires specified changes in a decommissioning, restoration or similar liability to be added to, or deducted from, the cost of the asset to which it relates; the adjusted depreciable amount of the asset is then depreciated prospectively over its remaining useful life. Pembina has elected to apply the optional exemption available to first time adopters to comply with requirements to changes in such liabilities that occurred after the date of IFRS transition.

d. Share-based payment transactions

Pembina has elected the exemption for its shared-based payment plans, and will apply IFRS 2, *Share-Based Payments*, to all stock options granted after November 7, 2002 that vest or settle after December 31, 2009.

Material adjustments to the statement of cash flows

Interest paid and income taxes paid are included in the *Statement of Cash Flows*, whereas they were previously disclosed as supplementary information. Additionally, borrowing costs capitalized in relation to qualifying assets are presented as interest paid in operating activities. There are no other material differences between the statement of cash flows presented under IFRS and the statement of cash flows presented under previous Canadian GAAP.

Index to the notes to the reconciliations

Notes to the reconciliations

In addition to the adjustments listed below, certain balances have been reclassed from Canadian GAAP in accordance with IFRS.

a. Joint ventures

The Company has elected to apply a policy of equity accounting for the Company's joint venture entities. Under previous Canadian GAAP joint venture entities were proportionately consolidated.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	**Year Ended December 31, 2010**
Decrease in revenue	(22,912)
Decrease in cost of sales:	
Operating expense	5,584
Depreciation and amortization	5,928
	(11,400)
Increase in share of profit from equity accounted investees	9,103
Related effect on income tax expense	2,549
Increase in earnings	252

Consolidated Statement of Financial Position *($ thousands)*	**January 1, 2010**	**December 31, 2010**
Increase in Investment in equity accounted investees	196,330	190,739
Decrease in net property, plant and equipment	(84,710)	(82,533)
Decrease in net intangibles	(50,942)	(47,191)
Decrease in goodwill	(65,000)	(65,000)
Related tax effect	4,542	4,457
Decrease in deficit	220	472

b. Share-based payments

Stock options

The Company grants options to certain employees. These options were accounted for as equity-settled share-based payment under Canadian GAAP. The Company was an income fund until October 1, 2010 and the options granted related to units issued by the Company. As those units contain a redemption feature, IFRS requires the related options to be accounted for as cash-settled share-based payments. Therefore, under IFRS, a liability has been recognized at January 1, 2010 which is remeasured at period end to reflect the fair value of the outstanding options. On October 1, 2010, the Company converted from Pembina Pipeline Income Fund to Pembina Pipeline Corporation at which time the options are accounted as equity-settled.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	**Year Ended December 31, 2010**
Increase in cost of sales (operating expense)	(5,932)
Decrease in general and administrative expense	119
Decrease in earnings	(5,813)

Consolidated Statement of Financial Position *($ thousands)*	**January 1, 2010**	**December 31, 2010**
Increase in share-based payment, non-current	(8,695)	
Increase in share capital	2,992	(11,516)
Increase in deficit	(5,703)	(11,516)

Long-term share unit award incentive plan

Under Canadian GAAP, Pembina recognized payments under the plan as they vested and become due. Under IFRS, grants made under the plan are considered cash-settled, and as such, a liability is incurred for service rendered that is measured at the fair value. Until the liability is settled, the fair value of this liability is remeasured at each reporting date.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	**Year Ended December 31, 2010**
Decrease in cost of sales (operating expense)	30
Increase in general and administrative expense	(523)
Related effect on income tax expense	123
Decrease in earnings	(370)

Consolidated Statement of Financial Position *($ thousands)*	**January 1, 2010**	**December 31, 2010**
Increase in trade payables and other	(731)	(164)
Increase in share-based payments, non-current	(4,194)	(5,252)
Related tax effect	1,232	1,353
Increase in deficit	(3,693)	(4,063)

c. Defined benefit pension plans

Under IFRS, the Company recognizes all actuarial gains and losses for its defined benefit pension plans immediately in other comprehensive income. Under previous Canadian GAAP, the Company applied the corridor method to these actuarial gains and losses. At the date of transition, all previously unrecognized cumulative actuarial gains and losses were therefore recognized in the deficit. In addition, the unrecognized actuarial gains and losses exceeding the corridor that were recognized in profit or loss for year ending December 31, 2010 under previous Canadian GAAP were reversed.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	**Year Ended December 31, 2010**
Decrease in cost of sales (operating expense)	593
Decrease in general and administrative expense	380
Related effect on tax expense	(243)
Increase in earnings	730

Consolidated Statement of Financial Position *($ thousands)*	**January 1, 2010**	**December 31, 2010**
Decrease in employee benefits asset, non-current	(19,928)	(25,058)
Decrease in deferred tax liability	4,982	6,265
Decrease in accumulated other comprehensive income		4,577
Increase in deficit	(14,946)	(14,216)

d. Decommissioning provision

Consistent with IFRS, the decommissioning provision has been previously measured under Canadian GAAP based on the estimated cost to dismantle, decommission and remediate facility sites, discounted to their net present value upon initial recognition. Under IFRS, the Company has estimated the net present value of the obligation discounted using a risk free rate. Under Canadian GAAP, the obligation was discounted using a credit adjusted risk free rate. The transition to IFRS resulted in a $112.9 million increase in the obligation and the deficit as at January 1, 2010. Consequently, for the year ended December 31, 2010, the Company recorded increased accretion of $1.3 million under IFRS. At December 31, 2010, the Company re-measured the asset retirement obligation based on a change in the discount rate from 4.08 percent to 3.54 percent, which increased property, plant and equipment and asset retirement obligations by $64.8 million.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	**Year Ended December 31, 2010**
Increase in cost of sales (operating expense)	(1,556)
Increase in finance costs (accretion expense)	(1,304)
Related effect on tax expense	715
Decrease to earnings	(2,145)

Consolidated Statement of Financial Position *($ thousands)*	**January 1, 2010**	**December 31, 2010**
Increase in property, plant and equipment	72	64,570
Increase in provision	(112,899)	(180,257)
Related tax effect	28,207	28,922
Increase in deficit	(84,620)	(86,765)

e. Lease reclassification

IFRS classifies a lease as either a finance lease or an operating lease. Lease classification depends on whether substantially all of the risks and rewards incidental to ownership of the leased asset have been transferred from the lessor to the lessee. Under IFRS, the Company is required to classify previously recognized vehicle operating leases as finance leases.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	Year Ended December 31, 2010
Increase in finance costs	(344)
Decrease in cost of sales (operating expense)	2,043
Increase in cost of sales (depreciation and amortization)	(1,587)
Related effect on tax expense	(28)
Increase in earnings	84

Consolidated Statement of Financial Position *($ thousands)*	January 1, 2010	December 31, 2010
Increase in property, plant and equipment	4,405	4,610
Increase in loans and borrowings, current	(1,901)	(2,074)
Increase in loans and borrowings, non-current	(2,560)	(2,482)
Related tax effect	13	(13)
Increase (decrease) in deficit	(43)	41

f. Derivative financial instruments

Interest rate and power derivatives

On transition, the Company elected not to apply hedge accounting to its interest rate and power hedge contracts. Future fluctuations in the fair value of these contracts is accounted for through the statement of comprehensive income. This accounting policy could result in increased volatility for future periods.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	Year Ended December 31, 2010
Increase in net finance costs	(3,700)
Related effect on tax expense	925
Decrease in earnings	(2,775)

Consolidated Statement of Financial Position *($ thousands)*	January 1, 2010	December 31, 2010
Decrease in deferred tax liability	5	
Decrease in other comprehensive income	(4,341)	(7,111)
Increase in deficit	(4,336)	(7,111)

Convertible debentures

On transition to IFRS, the 7.35% convertible debentures have been accounted for as a hybrid instrument because of the redemption feature of the trust units (that the convertible debenture would have been converted into) for the period prior to the conversion to a Corporation. The convertible embedded derivative is fair valued at each reporting period, until the date the Income Fund converted to a corporation. The 7.35% convertible debentures were converted in full prior to December 31, 2010.

The impact arising from the change is summarized as follows:

Consolidated Statement of Comprehensive Income *($ thousands)*	Year Ended December 31, 2010
Increase in finance costs	(63)
Decrease in earnings	(63)

Consolidated Statement of Financial Position *($ thousands)*	January 1, 2010	December 31, 2010
Increase in derivative financial instrument liability	(150)	
Increase in share capital		(213)
Increase in deficit	(150)	(213)

g. Employee benefit provision

A vacation accrual for the accumulated compensated absence has been recognized, increasing trade payables by $587 thousand (net of tax) as at December 31, 2010 with an offset to the deficit.

h. Income tax

The above changes decreased (increased) the deferred tax liability based on a tax rate of 25 percent:

($ thousands)	Note	January 1, 2010	December 31, 2010
Joint ventures	a	4,542	4,457
Share-based payments	b	1,232	1,353
Defined benefit pension plans	c	4,982	6,265
Decommissioning provisions	d	28,207	28,922
Lease reclassification	e	13	(13)
Derivative financial instruments	f	5	
Employee benefit provision	g	182	196
Income tax	h	(19,132)	(19,860)
Decrease in deferred tax liability		20,031	21,320

The effect on the statement of comprehensive income for the year ended December 31, 2010 was to decrease the previous reported tax charge for the period by $3,328 thousand.

In addition to the impact of the IFRS adjustments, the Company recognized a rate change on trust level deductions at January 1, 2010, resulting in a $668.4 thousand decrease to deferred tax liability. The adjustment was reversed on conversion to a Corporation on October 1, 2010.

The Company also recognized a deferred tax liability of $19.8 million relating to the cost of service agreement on transition to IFRS with an offsetting increase to the deficit.

i. Deficit

The above changes increased (decreased) deficit (each net of related tax) as follows:

($ thousands)	Note	January 1, 2010	December 31, 2010
Joint ventures	a	220	472
Share-based payments, stock options	b	(5,703)	(11,516)
Share-based payments, RSU	b	(3,693)	(4,063)
Defined benefit pension plan	c	(14,946)	(14,216)
Decommissioning provision	d	(84,620)	(86,765)
Lease reclassification	e	(43)	41
Derivative financial instruments	f	(4,336)	(7,111)
Convertible debentures	f	(150)	(213)
Employee benefit provision	g	(545)	(587)
Deferred tax	h	(19,132)	(19,860)
Increase in deficit		(132,948)	(143,818)

CORPORATE INFORMATION

HEAD OFFICE

Pembina Pipeline Corporation
Suite 3800, 525 – 8th Avenue S.W.
Calgary, Alberta T2P 1G1

AUDITORS

KPMG LLP
Chartered Accountants
Calgary, Alberta

TRUSTEE, REGISTRAR & TRANSFER AGENT

Computershare Trust Company of Canada
Suite 600, 530 - 8th Avenue SW
Calgary, Alberta T2P 3S8
1-800-564-6253

STOCK EXCHANGE

Pembina Pipeline Corporation
TSX listing symbols for:
Common shares: PPL
5.75% convertible debentures: PPL.DB.C

INVESTOR INQUIRIES

Phone:	(403) 231-7500
Fax:	(403) 237-0254
Toll Free	1-888-428-3222
Email:	investor-relations@pembina.com
Website:	www.pembina.com