ENBRIDGE INCOME FUND

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2013

MANAGEMENT'S DISCUSSION & ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2013

This Management's Discussion and Analysis (MD&A) dated February 10, 2014 should be read in conjunction with the audited consolidated financial statements and notes thereto of Enbridge Income Fund (the Fund) as at and for the year ended December 31, 2013, which are prepared in accordance with United States generally accepted accounting principles (U.S. GAAP). Comparative figures contained in this MD&A have been restated in accordance with U.S. GAAP. Unless otherwise noted, all financial information is presented in Canadian dollars. Additional information related to the Fund, including its Annual Information Form, is available on SEDAR at www.sedar.com.

OVERVIEW

The Fund is involved in the generation, transportation and storage of energy through its interests in 579 (524 net) megawatts (MW) of renewable and alternative power generation capacity (Green Power), its liquids transportation and storage business in Western Canada (Liquids Transportation and Storage) and natural gas transmission through its 50% interest in the Canadian segment of Alliance Pipeline (Alliance Canada).

The unitholders of the Fund are Enbridge Income Fund Holdings Inc. (ENF), a public company listed on the Toronto Stock Exchange (TSX), and Enbridge Inc. (Enbridge), a North American transporter, distributor and generator of energy. Enbridge's total economic interest in the Fund was 67.3% as at December 31, 2013 and February 10, 2014 based on its indirect interest in the Fund through ENF, its direct interest in the Fund via common units and its interest in preferred units of a subsidiary of the Fund, Enbridge Commercial Trust (ECT).

FINANCIAL OVERVIEW

Earnings and cash available for distribution (CAFD) in 2013 reflected the start-up of the Bakken Expansion in the first quarter of 2013, as well as the first full year of contributions from the $1.16 billion acquisition of crude oil storage facilities and wind and solar power generation facilities in December 2012 (the 2012 Acquisition). The acquired assets included the Hardisty Contract Terminals, the Hardisty Storage Caverns, the 99 MW Greenwich Wind Project, the 15 MW Amherstburg Solar Project and the 5 MW Tilbury Solar Project (the Crude Oil Storage and Renewable Energy Assets). Partially offsetting the increase in CAFD from these growth initiatives was an increase in associated interest expense on debt to finance a portion of the 2012 Acquisition.

The Fund commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012 which requires the acquirer in an acquisition of entities under common control to present the results of operations of the assets as if the acquirer had always owned the assets. Under U.S. GAAP, the 2012 Acquisition qualifies as a transaction among entities under common control as the assets were purchased from Enbridge. As such, earnings for the year ended December 31, 2012 report the results of the Fund and the Crude Oil Storage and Renewable Energy Assets on a combined basis as though the 2012 Acquisition occurred on January 1, 2011. Accordingly, earnings for the year ended December 31, 2012 include retrospective adjustments as identified in the following table. The retrospective adjustments may not be comparable to results generated under the Fund's direct ownership as historic performance would have been influenced by assets financed differently and assets not yet constructed and in-service. The impacts of the retrospective adjustments have been eliminated from the determination of CAFD.

	Three months ended December 31,		Year Ended December 31,	
	2013	2012	**2013**	2012
(millions of Canadian dollars)				
Earnings				
Green Power	**23.6**	13.8	**94.2**	70.7
Liquids Transportation and Storage	**16.5**	13.6	**50.7**	50.3
Alliance Canada	**12.8**	13.8	**54.1**	53.2
Corporate	**(30.8)**	(30.2)	**(119.2)**	(116.4)
	22.1	11.0	**79.8**	57.8
Retrospective Adjustments				
Green Power – 2012 Acquisition	**-**	3.9	**-**	19.1
Liquids Transportation and Storage – 2012 Acquisition	**-**	1.7	**-**	12.8
Earnings	**22.1**	16.6	**79.8**	89.7
Cash available for distribution[1]				
Green Power	**38.5**	26.5	**155.8**	121.4
Liquids Transportation and Storage	**33.1**	18.5	**130.2**	74.2
Alliance Canada	**16.8**	16.5	**68.4**	70.9
Corporate	**(23.4)**	(17.7)	**(91.2)**	(70.9)
	65.0	43.8	**263.2**	195.6

1 See definition within "Non-GAAP Measures" section, as well as the reconciliation to Cash Provided by Operating Activities.

Green Power earnings for the three and twelve months ended December 31, 2013 were higher than the comparable periods of 2012, reflecting positive contributions from the Greenwich Wind Project, Amherstburg Solar Project and Tilbury Solar Project following their acquisition from wholly-owned subsidiaries of Enbridge in December 2012.

Liquids Transportation and Storage earnings for the three and twelve months ended December 31, 2013 increased over the same periods of the prior year due to incremental cash flows from the Hardisty Contract Terminals and Hardisty Storage Caverns acquired in December 2012 and the Bakken Expansion which commenced operations on March 1, 2013. This was offset by lower earnings from the Westspur System as throughput levels, which now directly impact earnings for Westspur under the new negotiated toll structure that commenced on April 1, 2013, continued to be below 2012 levels. This reflects increased competition from rail, attributable to wide crude oil price differentials between local delivery points and delivery points which have access to world market prices at tidewater due to the current absence of pipeline infrastructure to those markets. For the year ended December 31, 2013, the Liquids Transportation and Storage business was impacted by an extraordinary pre-tax write-off of $16.5 million as a consequence of discontinuing rate regulated accounting for the Westspur System. On April 1, 2013, the Fund announced it substantially concluded a settlement (the Settlement) with a group of shippers relating to new tolls on the Westspur System. The Settlement resulted in the discontinuance of rate regulated accounting for the Westspur System and the Fund recorded a write-off related to a deferred regulatory asset which will not be collected under the terms of the Settlement. Earnings for the year ended December 31, 2013 also reflect non-cash charges totalling $2.6 million for the Hardisty Storage business.

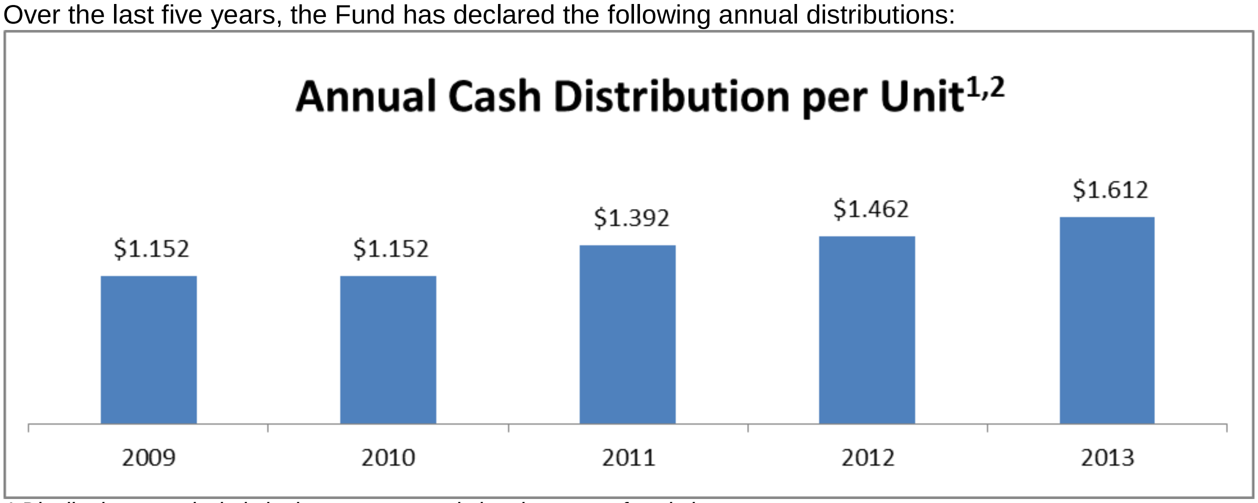
Alliance Canada earnings were $54.1 million for the year ended December 31, 2013, an increase from the comparable period in 2012 due to escalating negotiated depreciation rates recovered in transportation tolls. For the quarter ended December 31, 2013, earnings decreased from the fourth quarter of 2012 due to a lower return on equity resulting from a depreciating investment base.

Corporate costs, which include taxes, financing costs and management and administrative expenses, increased for the three and twelve month periods of 2013 as compared to the same periods of 2012 due to higher interest expense arising from the long-term debt incurred in the fourth quarter of 2012 to partially finance the 2012 Acquisition, as well as higher incentive fees resulting from a per unit increase in Fund distributions. The increase for the year ended December 31, 2013 was partially offset by a $4.5 million deferred tax recovery in connection with the Westspur System deferred regulatory asset write-off in the first quarter of 2013.

The Fund's CAFD totaled $65.0 million and $263.2 million for the three and twelve months ended December 31, 2013, respectively, representing increases of 48% and 35% from the respective prior year periods. The increases were driven primarily by positive contributions from the Crude Oil Storage and Renewable Energy Assets acquired in December 2012 and the Bakken Expansion which was put into service in March 2013, partially offset by increased interest expense associated with the higher debt balances used to finance a portion of the 2012 Acquisition.

Effective with the December 2012 distribution, the Fund's monthly distribution increased to $0.134 per unit. This increase was supported by incremental cash flow due to the 2012 Acquisition. The Fund increased its distribution to unitholders to $0.135 per unit with the November 2013 distribution.

Over the last five years, the Fund has declared the following annual distributions:



1 Distributions may include both a return on capital and a return of capital.
2 Figures present distributions on both the Fund's trust units and ECT preferred units.

Forward-Looking Information

In the interest of providing the Fund's unitholders and potential investors with information about the Fund, its subsidiaries and joint ventures, including management's assessment of the Fund, its subsidiaries' and joint ventures' future plans and operations, certain information provided in this MD&A constitutes forward-looking statements or information (collectively, "forward-looking statements").This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe" and similar words suggesting future outcomes or statements regarding an outlook. In particular, forward-looking statements included or incorporated by reference in this document include, but are not limited to, statements with respect to:

- *expected costs related to projects under construction;*
- *expected scope and in-service dates for projects under construction;*
- *expected timing and amount of recovery of capital costs of assets;*
- *expected capital expenditures;*
- *expected future levels of demand for the Fund's products and services;*
- *expected future earnings and cash flows;*
- *expected future actions of regulators;*
- *expected future distributions to unitholders and the taxability thereof; and*
- *expected cash available for distribution.*

Although the Fund believes that these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about: the expected supply and demand for crude oil, natural gas, natural gas liquids and green energy; prices of crude oil, natural gas, natural gas liquids and green energy; expected exchange rates; inflation; interest rates; the availability and price of labour and construction materials; operational reliability; customer project approvals; maintenance of support and regulatory approval for the Fund's projects; anticipated in-service dates and weather. Assumptions regarding the expected supply and demand of crude oil, natural gas, natural gas liquids and green energy, and the prices of these commodities, are material to and underlay all forward-looking statements. These factors are relevant to all forward-looking statements as they may impact current and future levels of demand for the Fund's products and services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which the Fund operates, may impact levels of demand for the Fund's products, services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to expected earnings and associated per unit amounts, or estimated future distributions. The most relevant assumptions associated with forward-looking statements on projects under construction, including estimated in-service dates, and expected capital expenditures include: the availability and price of labour and construction materials; the effects of inflation on labour and material costs; the effects of interest rates on borrowing costs; and the impact of weather and customer and regulatory approvals on construction schedules.

The Fund's forward-looking statements are subject to risks and uncertainties pertaining to operating performance, regulatory parameters, project approval and support, weather, economic and competitive conditions, changes in tax law, tax rates, exchange rates, interest rates, commodity prices and supply and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in the Fund's other filings with Canadian securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and the Fund's future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by law, the Fund assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to the Fund or persons acting on the Fund's behalf, are expressly qualified in their entirety by these cautionary statements.

Non-GAAP Measures

This MD&A contains references to the Fund's cash available for distribution (CAFD). CAFD represents the Fund's cash available to fund distributions on trust units and ECT preferred units as well as for debt repayments and reserves. CAFD consists of operating cash flow from the Fund's underlying businesses less deductions for maintenance capital expenditures, the Fund's administrative and operating expenses, corporate segment interest expense, applicable taxes and other reserves determined by the Manager. This measure is important to unitholders as the Fund's objective is to provide a predictable flow of distributable cash to unitholders. Please refer to the CAFD reconciliation within this MD&A. CAFD is not a measure that has standardized meaning prescribed by United States Generally Accepted Accounting Principles (U.S. GAAP) and is not considered a GAAP measure. Therefore, this measure may not be comparable with similar measures presented by other issuers.

FUND DESCRIPTION

The Fund is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta. The Fund commenced operations on June 30, 2003. Enbridge Management Services Inc. (EMSI or the Manager), a wholly-owned subsidiary of Enbridge, administers the Fund. EMSI also serves as the manager of ECT and ENF.

On December 17, 2010, the Fund was restructured pursuant to a plan of arrangement (the Plan). Under the Plan, 20,125,000 publicly held trust units of the Fund, as well as 5,000,000 trust units held by Enbridge, were exchanged on a one-for-one basis for shares of ENF, a taxable publicly-traded Canadian corporation. Concurrently, the Fund's trust units ceased trading on the Toronto Stock Exchange, and the ENF shares were listed. Subsequent to implementation of the Plan, the Fund ceased to be a specified investment flow-through (SIFT) entity and therefore is not subject to SIFT tax legislation.

The following table presents the direct and indirect ownership of the Fund:

	At February 10, 2014
Enbridge Income Fund Holdings Inc. *(number of common shares outstanding)*	
Held by public	**45,249,000**
Held by Enbridge	**11,242,000**
	56,491,000
Enbridge Income Fund *(number of common units outstanding)*	
Held by Enbridge	**9,500,000**
Held by Enbridge Income Fund Holdings Inc.	**56,491,000**
	65,991,000
Enbridge Commercial Trust *(number of preferred units outstanding)*	
Held by Enbridge	**72,465,750**
Total number of common units and ECT preferred units outstanding	**138,456,750**

Core Business
The Fund's activities are carried out through three operating segments:

- Green Power includes assets that produce electricity via renewable and alternative energy sources and consist of the 190 MW Ontario Wind Project, the 99 MW Talbot Wind Project, the 80 MW Sarnia Solar Project, the 99 MW Greenwich Wind Project, the 15 MW Amherstburg Solar Project, the 5 MW Tilbury Solar Project, a 50% interest in each of NRGreen and the SunBridge wind project, as well as a 33% interest in each of the Magrath and Chin Chute wind projects.
- Liquids Transportation and Storage owns and operates the crude oil and liquids pipeline systems in Saskatchewan which connect to Enbridge's mainline pipeline for transportation to the United States at Cromer, Manitoba, and liquids storage assets in Saskatchewan and Alberta. Liquids Transportation and Storage also includes the Canadian portion of the Bakken Expansion, a joint project which expands crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in North Dakota.
- Alliance Canada includes the Fund's 50% interest in the Canadian segment of the Alliance System, a natural gas pipeline system, comprised of Alliance Canada and Alliance US, that transports natural gas from supply areas in northwestern Alberta and northeastern British Columbia to delivery points near Chicago, Illinois.

FUND OBJECTIVES AND STRATEGY

The Fund's objectives are to provide a predictable flow of distributable cash and to increase, where prudent, cash distributions per trust unit through investment in and ongoing management of lower risk energy infrastructure assets.

In order to achieve the Fund's objectives, the Manager pursues three principal strategies which entail:

- maximizing the efficiency and profitability of its existing assets while ensuring safe and reliable operations;
- pursuing organic growth and expansion opportunities; and
- acquiring and developing energy infrastructure businesses that are complementary and in keeping with the risk and return profile of its existing business.

Each of the Fund's businesses is closely focused on system performance and operating effectiveness. Green Power strategies are driven by the objective to manage and maintain its facilities in such a way to maximize power generation and related revenue when the relevant wind, solar or waste heat energy resource is available. The Liquids Transportation and Storage business in Saskatchewan is focused on attracting new volumes to the System through increasing customer connections while working with customers to create reliable transportation solutions and toll structures to retain and attract growing regional production over the long term. The Liquids Transportation and Storage business at Hardisty, Alberta, is situated at a major hub for aggregating and exporting crude oil out of the Western Canadian Sedimentary Basin (WCSB). It is focused on connecting Canada's oil producers to markets in eastern Canada and the United States. Alliance Canada is implementing solutions to enhance its unique capability to safely and cost-effectively transport liquids rich gas (gas with a high component of inherent natural gas liquids) to attract growing production of high-value, liquids rich gas in the WCSB.

The expansion and extension of existing systems and facilities has been a significant driver of growth in recent years and the Fund continued to execute on its organic expansion strategy during 2013. The Bakken Expansion Program undertaken within Liquids Transportation and Storage was declared in service on March 1, 2013, bringing 145,000 barrels per day (bpd) of new capacity to producers in the Bakken region in North Dakota. The Fund continues to actively search for new opportunities to profitably grow the footprint of its existing assets and announced a $25 million Rail Interconnection Project in January 2014.

The Fund also seeks to achieve growth through acquisitions of complimentary energy infrastructure. In 2012, the Fund successfully executed its acquisition strategy with the completion of the 2012 Acquisition, which further diversified the Fund's overall business mix. The assets acquired are all underpinned by long-term fixed price contracts which generate steady cash flow and thereby lower the Fund's risk profile. Preservation of financial flexibility will continue to be a strategic priority. Ongoing access to cost effective sources of debt and equity capital is critical to the successful execution of the Fund's strategy to expand existing assets and acquire or develop new energy infrastructure.

GREEN POWER

Overview

Green Power includes assets that produce electricity from renewable and alternative energy sources. Each of the wind and solar assets is currently operating and has full-service operations and maintenance contracts with third parties. The cost to generate electricity through wind and solar resources is significantly lower than most other technologies, given the absence of fuel costs. Green Power consists of the following:

Wind Projects

The Fund has a 100% interest in the following projects which have an aggregate power generation capacity of 388 MW:

- The Ontario Wind Project, located near Lake Huron, Ontario, utilizes 115 turbines with an aggregate capacity of 190 MW.
- The Talbot Wind Project, located on the north shore of Lake Erie, Ontario, utilizes 43 turbines with an aggregate capacity of 99 MW.
- The Greenwich Wind Project, located on the north shore of Lake Superior, Ontario, utilizes 43 wind turbines with an aggregate capacity of 99 MW.

All power produced from these wind projects is sold to the Ontario Power Authority (OPA) pursuant to power purchase agreements (PPAs) which expire between 2028 and 2031.

The Fund also has interests in three wind power projects with a net capacity of 26 MW including:

- A 50% interest in the SunBridge Wind Project at Gull Lake, Saskatchewan, which utilizes 17 turbines with an aggregate capacity of 11 MW (6 MW net to the Fund).
- A 33% interest in each of the Magrath and Chin Chute Wind Projects in southern Alberta, each utilizing 20 turbines with an aggregate capacity of 30 MW per project (10 MW per project net to the Fund).

The power from SunBridge is delivered into the Saskatchewan power grid, while the energy produced at Magrath and Chin Chute is delivered into the Alberta power grid. Power price swap agreements, which are in place to mitigate the risk of fluctuating power prices in Alberta, expire between 2017 and 2024.

Solar Projects

The Fund has a 100% interest in the following solar generation projects with an aggregate capacity of 100 MW:

- The Sarnia Solar Project, an 80 MW solar project located near Lake Huron, in Sarnia, Ontario, comprised of approximately 1.3 million thin film panels with a surface area of 966,000 m^2.
- The Amherstburg Solar Project, a 15 MW solar project near Sarnia, Ontario, comprised of approximately 0.2 million thin film panels with a surface area of 175,700 m^2.
- The Tilbury Solar Project, a 5 MW solar project located near Sarnia, Ontario, comprised of 0.1 million thin film panels with a surface area of 67,700 m^2.

All power produced from these solar projects is sold to the OPA pursuant to PPAs which expire between 2028 and 2031.

Various inspection and monitoring methods as well as ongoing maintenance protocols are utilized to maintain the safety and integrity of the wind turbines, solar panels and related facilities, and to minimize system disruptions. The wind and solar projects owned by the Fund are subject to regular maintenance programs to maintain the life of the assets.

NRGreen

The Fund also has a 50% interest in NRGreen. NRGreen operates four waste heat recovery facilities with an aggregate capacity of 20 MW (10 MW net to the Fund), all of which are located in Saskatchewan at compressor stations along the Alliance Pipeline. The first facility located at Kerrobert, Saskatchewan has been operating since December 2006. The three other facilities, located in Loreburn, Estlin and Alameda, Saskatchewan, began operations during 2008. Electricity is generated by harnessing the waste heat produced by gas turbines at Alliance Canada’s compressor stations and converting the waste heat to electrical energy.

The power generated from the NRGreen facilities is sold under long-term PPAs to SaskPower. The PPAs expire ten years after the in-service date for each facility with two five-year options to renew at NRGreen’s election, to provide an additional ten-year extension to the initial PPA term.

Regular maintenance of NRGreen’s facilities is performed concurrently with the Alliance Canada semi-annual inspection of the Kerrobert, Loreburn, Estlin and Alameda compressor stations.

The Whitecourt Recovered Energy Project is a new waste heat recovery facility being constructed by NRGreen, adjacent to a compressor station on the Alliance Pipeline near Whitecourt, Alberta. The Fund has contributed approximately $42 million as at December 31, 2013 to the Whitecourt Recovered Energy Project. Completion of the project has been delayed due to various construction and equipment delivery challenges. Originally scheduled to be completed in 2013, completion is now anticipated to occur in the second quarter of 2014.

Results of Operations

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Financial highlights *(millions of Canadian dollars)*				
Earnings[1]	**23.6**	13.8	**94.2**	70.7
Retrospective Adjustment – 2012 Acquisition	**-**	3.9	**-**	19.1
	23.6	17.7	**94.2**	89.8
Operating highlights[1] *(thousands of megawatt hours produced)*				
Wind Projects (including joint ventures)	**350.8**	265.2	**1,149.0**	877.1
Solar Projects	**23.3**	15.8	**147.8**	128.0
Waste Heat (50%)	**19.7**	18.2	**70.7**	70.6
	393.8	299.2	**1,367.5**	1,075.7

1 Earnings and power production are presented before the effects of retrospective adjustments.

Green Power earnings for the three and twelve months ended December 31, 2013 were higher than the comparable periods of 2012, reflecting positive contributions from the Greenwich Wind Project, the Amherstburg Solar Project and the Tilbury Solar Project following the 2012 Acquisition. Partially offsetting this increase were lower earnings from the Sarnia Solar Project attributable due to lower irradiance than the same periods of the prior year, as well as unusually high snowfall conditions which impacted panel performance during the winter months of 2013. Performance from the Greenwich Wind Project was also impacted by low wind resource as well as cold weather related turbine outages in the winter months.

Business Risks

The risks identified below are specific to the Green Power segment. General risks that affect the Fund as a whole are described under Risk Management.

Regulatory

Renewable generators are classified as intermittent generators under Ontario's Independent Electricity System Operator Market Rules (IESO Market Rules). Amendments to the IESO Market Rules were passed on November 29, 2012, to allow for curtailment of intermittent generators in times of surplus base-load generation. The Fund and other renewable power generators reached an agreement with the OPA in February 2013 to amend certain existing power purchase agreements to include both annual and contract term curtailment caps beyond which renewable power generators will be compensated for forgone production. The Fund expects uncompensated curtailment, which will impact the Ontario Wind Project, Talbot Wind Project and Greenwich Wind Project, to be less than 1% of the operating hours of the affected assets both annually and over the life of the PPAs.

Asset Utilization

Earnings from the Fund's wind and solar assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for the wind and solar assets are predicted using long-term historical data, wind and solar resources will be subject to natural variation from year to year and from season to season. Any prolonged reduction in wind or solar resources at any of the Fund's facilities could lead to decreased earnings for the Fund. Additionally, inefficiencies or interruptions of the Fund's facilities due to operational disturbances or outages could also impact earnings. The Fund mitigates the risk of operational availability by establishing Operations and Maintenance contracts with the original equipment manufacturers that include a negotiated operational performance asset guarantee. The Fund also monitors the operational reliability of the assets on a 24-hour basis to monitor asset performance.

Transmission Systems

The ability to deliver electricity is affected by the availability of the various transmission and distributions systems in the areas in which it operates. The failure of existing transmission or distribution facilities or lack of adequate transmission or distribution capacity could have a material adverse effect on the ability to deliver electricity and receive payment under the PPAs.

LIQUIDS TRANSPORTATION AND STORAGE

Overview

The Fund's Liquids Transportation and Storage business serves customers in Western Canada and North Dakota and includes the Saskatchewan System which transports crude oil and natural gas liquids (NGLs) from producing fields and facilities in southeastern Saskatchewan, southwestern Manitoba and North Dakota to Cromer, Manitoba where the crude oil and NGLs enter Enbridge's Mainline System to be transported to the United States or eastern Canada. Liquids Transportation and Storage also includes related terminals and tankage facilities in Saskatchewan and the Hardisty Contract Terminals and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude pipeline hub in Western Canada.

Collectively referred to as the Saskatchewan System, the Saskatchewan Gathering, Westspur, Weyburn and Virden pipeline systems, as well as the Canadian portion of the Bakken Expansion, collectively comprise approximately 545 kilometres of trunk line and approximately 1,800 kilometres of gathering pipeline. The Bakken Expansion is a joint project which further expands crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in North Dakota. The capacity of each of the Saskatchewan Gathering and the Westspur Systems is 255,000 bpd, the capacity of the Weyburn and Virden Systems is approximately 47,000 bpd and 37,000 bpd, respectively, and the capacity of the Bakken Expansion is 145,000 bpd. The Saskatchewan System also includes storage terminals and tankage facilities in Saskatchewan, comprised of 21 above ground storage tanks with total capacity of approximately 450,000 barrels.

The Hardisty Contract Terminals are located adjacent to Enbridge's Mainline System terminal in Hardisty, Alberta are comprised of 18 above ground crude oil storage tanks, ranging in size from 250,000 to 560,000 barrels, and one above ground condensate storage tank with a capacity of 250,000 barrels which together have an aggregate storage capacity of 7.5 million barrels. The Hardisty Storage Caverns are comprised of four underground salt caverns and two above ground storage tanks, with approximately 3.5 million barrels of storage capacity. The above ground storage tanks are used primarily to facilitate movement of crude oil in and out of the caverns, as well as limited trim blending of product when operationally required. Each of the Hardisty assets has long-term take-or-pay storage contracts in place with credit-worthy counterparties in respect of virtually all of their storage capacity. Most of the revenue received under the storage contracts is comprised of fixed fees for storage capacity, with a small component derived from usage fees for services which vary with demand. Upon expiry or termination of existing contracts, Enbridge will enter into escalating take-or-pay contracts with the Fund for an additional 15 years based on then prevailing contract rate. The proximity of the Hardisty storage facilities, which are adjacent to Enbridge's Mainline System operational terminal and at the junction of various regional receipt and export pipelines, make it an attractive option for oil producers to manage their operational needs and the effects of crude oil price swings.

The Liquids Transportation and Storage maintenance program is designed to maintain the productive capacity of the pipelines and storage assets and includes sump tanks, berm and line repairs, piping modifications, and tank and meter repairs. Maintenance expenditures will vary year to year as some maintenance is performed on a cyclical basis. Tank repairs occur annually, although the extent of repairs will fluctuate each year based on the age and size of the tank. The maintenance program also includes annual system integrity management which consists of cathodic protection, installation and maintenance, inline inspections and repairs, station and tank inspection and repairs, as well as chemical injections to inhibit corrosion.

Results of Operations

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Financial highlights *(millions of Canadian dollars)*				
Earnings before extraordinary item[1]	**16.5**	13.6	**67.2**	50.3
Extraordinary item	**-**	-	**(16.5)**	-
Retrospective Adjustment – 2012 Acquisition	**-**	1.7	**-**	12.8
	16.5	15.3	**50.7**	63.1
Operating highlights *(thousands of barrels per day)*				
Liquids Transportation and Storage[1, 2]				
Westspur System	**170.6**	173.6	**164.3**	182.4
Saskatchewan Gathering System	**130.1**	123.4	**119.5**	129.8
Weyburn System	**31.6**	30.8	**31.5**	31.5
Virden System	**26.4**	22.3	**24.5**	23.2
Bakken Expansion	**4.1**	-	**9.8**	-

1 Presented before the effects of retrospective adjustments.
2 Totals are not presented as the same volumes can be transported through a combination of the pipelines comprising the Liquids Transportation and Storage segment.

Earnings before extraordinary item for the three and twelve months ended December 31, 2013 increased compared to the same periods of the prior year due to incremental cash flows from the Hardisty Contract Terminals and Hardisty Storage Caverns acquired in December 2012. The Bakken Expansion which commenced operations in March 2013 also contributed incremental earnings to the Fund. Earnings for the twelve months ended December 31, 2013 were impacted by a $1.9 million non-cash charge in connection with the write-off of project costs incurred at the Hardisty Contract Terminals prior to the 2012 Acquisition, relating to an in-progress regulatory-directed project which was subsequently determined to be unnecessary by the Fund and regulator. Earnings for the twelve months ended December 31, 2013 also included a $0.7 million non-cash charge related to a volumetric adjustment in the Hardisty Caverns.

On April 1, 2013, the Fund announced it concluded a settlement (the Settlement) with a group of shippers relating to new tolls on the Westspur System. At the request of certain shippers that did not execute the settlement, the National Energy Board (NEB) did not remove the interim status from the historical tolls and made the new tolls interim as well. A modified agreement was subsequently entered into with substantially all of the shippers, and such shippers requested the NEB make both the historical tolls and the new tolls (collectively, the "Tolls") final. On February 6, 2014, the NEB ordered the Tolls final.

The Settlement establishes a toll methodology for an initial term of five years and will renew for additional one year terms thereafter unless otherwise terminated. Pursuant to the Settlement, the tolls on the Westspur System are fixed and increase annually with reference to an inflation index, subject to throughput remaining within a prescribed volume band close to volumes recently transported on the Westspur System. To preserve a relatively stable cash flow profile, toll surcharges or discounts will be applied should throughput increase or decrease on a sustained basis outside this pre-defined band. Additionally, tolls will be increased should integrity or regulatory costs exceed defined thresholds or if new capital projects are undertaken.

The Settlement resulted in the discontinuance of rate regulated accounting for the Westspur System and as such the Fund recorded an after-tax write-off of $12.0 million in the first quarter of 2013 related to previously-recorded deferred revenue which will not be collected under the terms of the Settlement. The financial impact of the Settlement is not expected to materially affect the Fund's consolidated financial prospects, distribution coverage or practices.

Throughput volumes decreased on the Westspur System for the three and twelve months ended December 31, 2013, respectively, compared to the same periods of the prior year due to customers using alternative transportation options, primarily rail. The increased use of rail is attributable to wide crude oil price differentials between local delivery points and delivery points which have access to world market prices at tidewater due to the current absence of pipeline infrastructure to those markets. Throughput volumes on the Saskatchewan Gathering System improved for the quarter ended December 31, 2013 compared to the comparable quarter of the prior year as narrowing price differentials resulted in a partial return to the Fund's pipeline systems. Management expects throughput to further recover on these systems as expansions on downstream pipelines and new market access projects relieve bottlenecks and further reduce price discounts for producers delivering into the Saskatchewan System. Volumes on the Weyburn and Virden Systems for the three months ended December 31, 2013 increased as compared to the same period of the prior year. Volumes on the Weyburn System were consistent for the year ended December 31, 2013 as compared to 2012, while volumes for the Virden System increased year over year. Throughput variances do not directly impact earnings on the Saskatchewan Gathering System since this system is cost of service based. Prior to the filing of the new tolls for the Westspur System with the NEB on April 1, 2013, throughput variances also did not impact earnings for the Westspur System. As a consequence of the new tolling structure and the discontinuance of rate-regulated accounting, earnings on the Westspur System became sensitive to volumetric throughput beginning in the second quarter of 2013. Similarly, throughput levels directly impact earnings of the Weyburn and Virden Systems, which operate on a basis similar to a common carrier and charge a market-based toll per barrel of crude oil transported.

Business Growth

Cromer Rail Interconnection Project

On January 29, 2014, the Fund announced plans to construct a pipeline interconnection that will connect the Westspur System and Bakken Expansion to a crude oil rail terminal near Cromer, Manitoba. The estimated cost of the project is $25 million and is expected to be in-service in the fourth quarter of 2014. The project is fully backstopped by the operator of the crude oil rail terminal pursuant to a five-year Financial Support Agreement. In addition, the Fund has an option to acquire 50% of the rail terminal which is currently capable of handling 30,000 bpd and is expandable to 60,000 bpd.

Bakken Expansion Program

The Bakken Expansion was undertaken to expand crude oil pipeline capacity to accommodate growing production from the Bakken and Three Forks formations located in North Dakota. This project, undertaken by the Fund in Canada and Enbridge Energy Partners (EEP), a party related to Enbridge, in the United States, reversed and expanded an existing pipeline, running from Berthold, North Dakota, to Steelman, Saskatchewan, and constructed a new 16-inch pipeline from a new pump station near Steelman to the Enbridge terminal near Cromer, Manitoba. It was placed into service in March 2013, providing capacity of 145,000 bpd to producers in North Dakota. Expenditures incurred by the Fund for the Canadian portion of the project through December 31, 2013 were approximately $165 million. After completion of site remediation and post-implementation expenditures, the total cost of the Canadian portion of the Bakken Expansion is expected to be under the original budget of approximately $190 million.

As a result of high crude oil differentials between local delivery points and markets not serviced by downstream pipelines, capacity was not well utilized in 2013. Crude differentials narrowed and throughputs improved modestly in the second half of 2013. The Fund continues to collect cash tolls regardless of actual system throughput pursuant to firm take-or-pay commitments totaling 100,000 bpd, a portion of which are subject to a waiver of 25% of the take-or-pay amount in 2013.

To the extent that committed shippers do not utilize committed capacity, they receive make-up rights which entitle them to utilize unused capacity commitments for a period of twelve months. Committed shippers are only entitled to use make-up rights to the extent that their volumes exceed their minimum commitments for that period and spot shippers have not used the available capacity. For the twelve months ended December 31, 2013, the Fund deferred revenue totalling $3.3 million, reflecting expected make-up rights utilization. Deferred revenue does not impact CAFD as cash tolls are non-refundable and the variable costs associated with transporting make-up volumes are passed through to shippers.

Regulatory and Tolling Matters
The Saskatchewan Gathering System and the Westspur System are regulated by the Saskatchewan Ministry of Economy and the NEB, respectively. The Saskatchewan Gathering System tolling agreement is based on a cost of service methodology, designed to provide toll revenues sufficient to recover operating costs, depreciation, deemed interest expense, deemed income tax and to provide an administrative expense allowance as well as a return on the asset base. The rate base upon which the equity return is calculated will change over time due to depreciation as well as maintenance and enhancement capital additions and expansions.

The Settlement with a group of shippers on the Westspur System on April 1, 2013 resulted in the new tolls no longer being subject to the cost of service methodology. On February 6, 2014, the NEB ordered historical and new tolls final in respect of the Settlement.

The Weyburn System and Virden System are regulated by the Saskatchewan Ministry of Economy and Manitoba Innovation, Energy and Mines, respectively. Rates are established based on signed customer agreements and are updated to reflect changing market conditions when warranted. As a result, earnings from these systems reflect toll revenue less costs incurred.

The Bakken Expansion is regulated by the NEB. Tolls on the Bakken Expansion are based on long-term take-or-pay agreements with anchor shippers.

Regulators also exercise authority over various matters such as construction, operations, rates and ratemaking agreements with customers, and underlying accounting principles.

Business Risks
The risks identified below are specific to the Liquids Transportation and Storage. General risks that affect the Fund as a whole are described under Risk Management.

Asset Utilization
The Fund is exposed to throughput risk under certain tolling agreements applicable to the Saskatchewan System assets. A decrease in volumes transported can directly and adversely affect revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, operational incidents, regulatory restrictions, system maintenance and increased competition can all impact the utilization of the Saskatchewan System assets. The market access and expansion projects under development by Enbridge are expected to reduce capacity bottlenecks and introduce new markets for customers.

Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative energy sources and global supply disruptions, outside of the Fund's control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on the Saskatchewan System.

The Fund seeks to mitigate utilization risks within its control, including working with the shipper community on its tolling agreements. Additionally, volume risk is somewhat mitigated for the Westspur System due to the fact that toll surcharges or discounts will be applied should throughput increase or decrease on a sustained basis outside a pre-defined band set as defined in the agreement.

Competition
Competition may result in a reduction in demand for the Saskatchewan System's services or assumption of risk that results in weaker or more volatile financial performance than expected. The Saskatchewan System faces competition in pipeline transportation from other pipelines as well as other forms of transportation, most notably rail. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers, thereby reducing shipments on the Saskatchewan System or resulting in pressure to reduce tolls. While the crude price differentials resulting from downstream bottlenecks will cause production to move to rail or other transportation options, the Fund believes its tolls will be competitive relative to alternative transportation options over the longer term due to the Saskatchewan System's right-of-way and its ability to execute relatively low cost.

Operational and Economic Regulation
Operational regulation risks relate to failing to comply with applicable operational rules and regulations from government organizations and could result in fines, operating restrictions and/or an overall increase in operating and compliance costs.

Regulatory scrutiny over the integrity of Liquids Transportation and Storage assets has the potential to increase operating costs or limit future projects. Any upgrades or changes could have an impact on the Fund's future earnings and the cost to construct new projects. The Fund and its sponsor, Enbridge, believe operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators, directly with the regulators or through industry associations. The Fund and its sponsor also develop robust response plans to regulatory changes or enforcement actions. While the Fund believes the safe and reliable operation of its assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on the Fund.

Broadly defined, economic regulation risk relates to the ability of regulators or other government entities to change or reject proposed or existing commercial arrangements. Certain pipelines within the Saskatchewan System are subject to the actions of various regulators, including the NEB. Actions of regulators related to tariffs, tolls and facilities impact earnings and the success of expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays. Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of the Fund's operations.

ALLIANCE CANADA

Overview

Alliance Canada consists of 1,560 kilometres of the Alliance System's natural gas mainline pipeline beginning near Gordondale, Alberta and connects to Alliance US at the Canada/United States border near Elmore, Saskatchewan. Alliance Canada also includes the Alliance System's lateral pipelines, which connect the mainline to a number of upstream receipt points, primarily at natural gas processing facilities in northwestern Alberta and northeastern British Columbia, and related infrastructure.

The Alliance System is designed to transport 1,325 million cubic feet per day of natural gas on a firm service basis primarily from supply areas in northwestern Alberta and northeastern British Columbia to delivery points near Chicago, Illinois. Additional transportation capacity is available to shippers for no additional cost other than the cost of the associated fuel requirements through Authorized Overrun Service (AOS).

Alliance Canada has transportation service agreements (TSAs) with shippers for substantially all of its available firm transportation capacity. The TSAs are designed to provide toll revenues sufficient to recover prudently incurred costs of service, including operating and maintenance, depreciation, an allowance for income tax, costs of indebtedness and an allowed return on equity of 11.26% after tax, based on a deemed 70/30 debt/equity ratio. The initial term of the TSAs expires in December 2015, with the exception of a small proportion of shippers that have elected to extend their contracts beyond 2015.

Tolls and tariffs for Alliance Canada are regulated by the NEB. Toll adjustments, based on variances between the cost of service forecast used to calculate the toll and the actual cost of service, are made annually. Following consultation with shippers, amended tolls are filed annually with the NEB.

Alliance Canada expects to continue to be competitive with other export pipelines given its geographic positioning and its ability to efficiently move liquids-rich gas to market. It is seeking to secure new term contracts for capacity for periods beyond 2015 (see also “Regulatory Matters – Transportation Contracts”).

Alliance Canada’s maintenance program includes semi-annual inspections of all compressor stations, internal corrosion inspections and annual pipe-to-soil surveys, atmospheric inspections, above ground indirect assessments and the repair and replacement of compressor parts. In-line inspection of the mainline pipeline is completed on a seven year recurring schedule. Maintenance expenditures may vary from year to year.

Results of Operations

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Financial highlights *(millions of Canadian dollars)*				
Earnings	**12.8**	13.8	**54.1**	53.2
Operating highlights *(millions of cubic feet per day)*				
Alliance Canada	**1,552.0**	1,474.0	**1,565.0**	1,534.0

The Fund’s earnings from its equity investment in Alliance Canada were $54.1 million for the twelve months ended December 31, 2013, an increase from the comparable period in 2012 attributable to higher negotiated depreciation rates recovered in transportation tolls. The increase was partially offset by Alliance Canada’s depreciating investment base and the NEB’s denial of the recovery of indirect costs incurred by Alliance Canada, resulting in a one-time charge to the Fund’s earnings of $2.1 million in the first quarter of 2013. Earnings for the fourth quarter of 2013 decreased from the same period of 2012 due to a lower return on equity resulting from a depreciating investment base. Under the current tolling arrangement, the rate used to calculate the equity return is not expected to change; however, the investment base upon which the equity return is calculated will change over time due to depreciation.

Alliance Canada throughput volumes increased for the three and twelve months ended December 31, 2013 as compared to the same periods of 2012. Throughput volumes for the 2012 periods were impacted by interruptions related to scheduled maintenance programs and the re-routing of a pipe, during which time firm service and AOS was curtailed. AOS refers to the physical capacity available on the Alliance Canada pipeline, over and above the contracted firm capacity. AOS offered was 18.0% for 2013, as compared to 17.2% offered in 2012. AOS volumes do not impact earnings; however, they increase the toll competitiveness of Alliance Canada’s transportation services.

Regulatory Matters

Transportation Contracts

Alliance Canada has long-term, take-or-pay contracts to transport substantially all its 1,325 million cubic feet per day of natural gas capacity. The majority of these long-term contracts expire December 1, 2015. These contracts permit Alliance Canada, whose operations are regulated by the NEB, to recover the cost of service, which includes operating and maintenance costs, the cost of financing, an allowance for income tax, an annual allowance for depreciation and an allowed return on equity of 11.26% after tax.

Alliance Canada is in discussions with the shipper community regarding its service offerings post the December 2015 expiry of the majority of existing contracts.

Business Risks

The risks identified below are specific to Alliance Canada. General risks that affect the Fund as a whole are described under Risk Management.

Asset Utilization

Currently, natural gas pipeline capacity out of the WCSB exceeds supply. Alliance Canada has been unaffected by the excess supply environment substantially all of its long-term capacity contracts extend until late 2015. However, excess capacity and depressed natural gas prices have led to a reduction or deferral of investment in upstream gas development, and could negatively impact the ability of Alliance Canada to recontract beyond 2015. Additionally, increased supply from new shale developments including the Marcellus shale formation, which is among the largest gas plays in North America, could displace gas from the WCSB to the United States Midwest, further increasing re-contracting risk.

Re-contracting risk is somewhat mitigated as the Alliance System is well positioned to deliver incremental liquids-rich gas production from developments in the Montney and Bakken regions to the Aux Sable NGL fractionation plant. The Alliance System is also engaged with market participants in developing new receipt facilities and services to expand its reach in transporting liquids-rich gas to premium markets.

Competition

The Alliance System faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects to transport gas from existing and new gas developments. Any new or upgraded pipelines could either allow shippers greater access to natural gas markets or offer natural gas transportation services that are more desirable than those provided by the Alliance System because of location, facilities or other factors. In addition, any new or upgraded pipelines could charge rates or provide transportation services to locations that result in greater net profit for shippers, with the effect of forcing the Alliance System to realize lower revenues and cash flows. The ability of the Alliance System to cost-effectively transport liquids-rich gas serves to enhance its competitive position.

CORPORATE

Overview

Corporate costs are comprised of corporate financing costs, management and administrative costs which include incentive fees paid to the Manager and current and deferred income taxes.

Results of Operations

	Three months ended December 31		Year ended December 31	
	2013	2012	**2013**	2012
Financial highlights *(millions of Canadian dollars)*				
Management and administrative	**5.5**	6.8	**21.8**	19.3
Interest and other	**19.0**	15.1	**73.5**	56.0
Income taxes	**6.3**	8.3	**23.9**	41.1
Corporate costs	**30.8**	30.2	**119.2**	116.4

For the three and twelve months ended December 31, 2013, the increase in Corporate costs was attributable mainly to higher interest expense associated with the long-term debt incurred in the fourth quarter of 2012 to partially finance the 2012 Acquisition. Management and administrative costs in the 2013 periods reflect increased incentive fees, which are based on distributions declared by the Fund compared to a predetermined level pursuant to the Management Agreement. As such, incentive fees increased due to higher monthly distributions of $0.134 per unit effective with the December 2012 distribution as compared to $0.121 per unit in the comparable periods of 2012. Distributions per Fund trust unit further increased to $0.135 effective with the November 2013 distribution. Management and administrative expenses for the 2012 comparable periods also reflect transaction costs incurred in connection with the 2012 Acquisition, which totalled $4.1 million for the year ended December 31, 2012.

The increase in Corporate Costs for the three and twelve months ended December 31, 2013 was partially offset by lower non-cash deferred income taxes. In 2012 periods, the Fund was able to utilize tax pools assumed from the renewable assets acquired in 2011 (the 2011 Acquisition) to offset taxable income, which resulted in deferred income taxes. In 2013 periods, the Fund continued to utilize tax pools as much as possible; however, permitted claims are lower in 2013 and a higher portion of distributions to unitholders are taxable. The Fund also realized a deferred income tax recovery of $4.5 million for the year ended December 31, 2013 resulting from the Westspur deferred revenue write-off of $16.5 million in the first quarter of 2013.

LIQUIDITY AND CAPITAL RESOURCES

In keeping with its low risk value proposition, the Fund actively monitors and manages exposure to financial risks. The Fund's financing strategy is to maintain strong, investment grade credit ratings and ongoing access to capital markets. To protect against more severe market disruptions, the Manager targets to maintain sufficient liquidity in the form of committed standby credit facilities to finance anticipated operating and capital requirements for at least a year without having to access long-term capital markets.

Cash Requirements

The following information about the Fund's contractual obligations and other commitments summarizes certain liquidity and capital resource requirements as at December 31, 2013. Liquidity needs can be met through a variety of sources, including cash from operations and drawdowns on available capacity under the Fund's committed standby credit facilities. The Fund maintains a current medium term note (MTN) shelf prospectus with Canadian securities regulators, which enables ready access to Canadian public capital markets, subject to market conditions. These sources are expected to be sufficient to meet currently forecasted liquidity and capital resource requirements of the Fund.

(millions of Canadian dollars)	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
Long-term debt	1,614.2	290.0	-	-	325.0	125.0	874.2
Operating leases	2.0	1.0	0.7	0.3	-	-	-
Maintenance agreements	57.6	12.5	14.3	11.8	10.1	4.5	4.4
Land lease commitments	36.6	1.9	2.4	2.4	2.4	2.5	25.0
Purchase commitments	3.0	3.0	-	-	-	-	-
Total	1,713.4	308.4	17.4	14.5	337.5	132.0	903.6

Sources and Uses of Cash

The Fund's primary uses of cash are distributions to unitholders, administrative and operational expenses, maintenance and enhancement capital spending, and interest and principal repayments on the Fund's long-term debt. Sources of cash include cash flows from operations, new offerings of debt and equity, as well as loans from affiliates.

Debt

Long-term debt consists of MTNs and a committed credit facility. No MTNs were issued during the year ended December 31, 2013.

At December 31, 2013, the Fund's credit facility was comprised of a $500.0 million, 3-year standby facility with a syndicate of commercial banks. The facility includes a feature under which up to $250.0 million of additional standby credit may be provided on the same terms and conditions as the existing facility. In June 2013, the Fund amended its facility, extending the maturity date to June 28, 2016. On an annual basis, the Fund may request the extension of the applicable maturity date of the facility by one year.

The Fund is subject to several covenants under its credit facility. During the year ended December 31, 2013, certain covenants were modified in the amended facility including the addition of a covenant that limits outstanding debt to a percentage of the Fund's consolidated capitalization and the elimination of a covenant which limited outstanding debt to a multiple of EBITDA (earnings before interest, taxes, depreciation and amortization). The Fund is in compliance with all covenants as at December 31, 2013.

At December 31, 2013, letters of credit totaling $12.0 million were outstanding and $448.0 million remained undrawn under the credit facility, available to meet liquidity requirements.

Equity
During the year ended December 31, 2013, the Fund issued trust units to ENF for gross proceeds of $119.2 million and ECT preferred units to Enbridge for gross proceeds of $130.8 million. The proceeds were primarily used to repay debt used to fund capital expenditures and to partially fund ongoing capital expenditures associated with the Fund's organic expansion strategy.

Distributions
During the first ten months of 2013, monthly distributions of $0.134 per unit were declared on the Fund trust units and ECT preferred units. Effective with the November 2013 distribution, the Fund's distribution rate increased to $0.135 per trust unit and ECT preferred unit.

Capital expenditures
The Fund's capital expenditures (including contributions to equity investees to fund expansion projects) were $76.8 million (2012 – $174.5 million) for the year ended December 31, 2013, of which $25.3 million was directed to the Bakken Expansion. Maintenance capital expenditures for the Liquids Transportation and Storage segment totalled $9.9 million (2012 – $12.1 million) for the year ended December 31, 2013. The Green Power segment incurred $1.6 million (2012 – $0.2 million) in maintenance capital expenditures for the year ended December 31, 2013. The Fund also made contributions to NRGreen of $21.1 million during the year ended December 31, 2013 (2012 – $16.0 million) to partially fund the Whitecourt Recovered Energy Project and spare equipment purchases for the Saskatchewan and Whitecourt facilities. The Fund expects to incur capital expenditures of approximately $97.0 million in 2014 related to organic growth projects including the Cromer Rail Interconnection project, site remediation costs related to the Bakken Expansion, and maintenance capital expenditures.

	Expected 2014	Actual 2013	Actual 2012
(millions of Canadian dollars)			
Capital expenditures			
Green Power[1]	**5.0**	23.6	16.0
Liquids Transportation and Storage	**90.0**	53.2	158.0
Alliance Canada[1]	**2.0**	-	0.5
	97.0	76.8	174.5
Retrospective Adjustments			
Green Power	**-**	-	1.5
Liquids Transportation and Storage	**-**	-	3.5
Total capital expenditures[2]	**97.0**	76.8	179.5

1 Capital expenditures include contributions to equity investees to fund expansion projects.
2 Capital expenditures represent cash additions to property, plant and equipment.

CASH AVAILABLE FOR DISTRIBUTION[1]

Year ended December 31,	**2013**	2012
(millions of Canadian dollars)		
Cash provided by operating activities	**260.1**	266.7
Crude Oil Storage and Renewable Energy Assets pre-Acquisition cash flows from operating activities[2]	**-**	(82.4)
Green Power maintenance capital expenditures[3]	**(1.6)**	(0.2)
Green Power joint venture cash distributed /(retained)[4]	**0.8**	0.2
Liquids Transportation and Storage maintenance capital expenditures[3]	**(9.9)**	(12.1)
Change in operating assets and liabilities in the year[5]	**13.8**	23.4
Cash available for distribution	**263.2**	195.6
Cash available for distribution is comprised of the following:		
Green Power operating income before depreciation and amortization	**153.7**	117.1
Green Power maintenance capital expenditures	**(1.6)**	(0.2)
Green Power joint venture distributions	**3.7**	4.5
Liquids Transportation and Storage operating income before depreciation and amortization	**140.1**	86.3
Liquids Transportation and Storage maintenance capital expenditures	**(9.9)**	(12.1)
Alliance Canada distributions	**68.4**	70.9
Corporate management and administrative expense	**(21.8)**	(19.3)
Corporate interest expense	**(68.3)**	(51.3)
Corporate current income tax expense	**(1.1)**	(0.3)
Cash available for distribution	**263.2**	195.6
ECT preferred unit distributions declared	**116.1**	80.8
Trust unit distributions declared	**105.8**	73.6
Cash distributions declared	**221.9**	154.4
Payout ratio	**84.3%**	78.9%

1 See Non-GAAP measures.
2 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. Cash provided by operating activities of the Renewable Assets and Crude Oil Storage and Renewable Energy Assets prior to their acquisition date have been deducted from CAFD as these cash flows were not available for distribution by the Fund.
3 Maintenance capital expenditures reduce cash available for distribution since these expenditures are funded through cash from operations.
4 The cash retained or distributed by certain Green Power joint ventures reflects the cash from operations of these segments that has not been distributed to the Fund or distributions in excess of cash earnings in the period. While this cash from operations is proportionately consolidated and included in the Fund's cash provided by operating activities, it is not available for distribution by the Fund until it has been received.
5 Change in operating assets and liabilities in the period reflect changes in non-cash working capital related to operating activities. The change has been added back to cash available for distribution since fluctuations in working capital are expected each period and are not indicative of changes in cash available to be distributed.

As set out in the previous table, CAFD consists of operating cash flow from the Fund's underlying businesses less deductions for maintenance capital expenditures, the Fund's administrative and operating expenses, corporate segment interest expense, applicable taxes and other reserves determined by the Manager. CAFD represents cash available to fund distributions on trust units and ECT preferred units, as well as for debt repayments and reserves.

For the year ended December 31, 2013, cash distributions declared represented 84.3% of cash available for distribution compared with 78.9% for the year ended December 31, 2012. The Fund targets to distribute a high proportion of CAFD each calendar year, after prudently reserving for contingencies and debt repayment.

ANALYSIS OF CASH DISTRIBUTIONS DECLARED

Year ended December 31,	**2013**	2012
(millions of Canadian dollars)		
Cash provided by operating activities[1]	**260.1**	266.7
Earnings[1]	**79.8**	89.7
Cash distributions declared	**221.9**	154.4
Excess of cash provided by operating activities over cash distributions declared	**38.2**	112.3
(Shortfall) of earnings over cash distributions declared	**(142.1)**	(64.7)

1 Cash provided by operating activities and earnings have been retrospectively adjusted to furnish comparative information related to the 2012 Acquisition as prescribed by U.S. GAAP for common control transactions.

For the year ended December 31, 2013, cash provided by operating activities exceeded cash distributions declared by $38.2 million (2012 – $112.3 million). Excess cash was reserved for debt repayments, working capital requirements and maintenance capital expenditures. Included in 2012 were retrospective adjustments totaling $69.4 million which were not available to distribute.

Earnings were $142.1 million lower than cash distributions for the year ended December 31, 2013 (2012 – $64.7 million). Earnings reflected non-cash items such as the extraordinary loss associated with the write-off of Westspur deferred revenue in the first quarter of 2013, amortization of deferred financing costs, depreciation and deferred income taxes, all of which do not impact cash flow. Depreciation does not necessarily represent the cost of maintaining productive capacity; therefore, cash required for maintenance is generally lower than depreciation expense. Earnings for 2012 also included retrospective adjustments totaling $31.9 million.

Taxation of Distributions and Dividends

Under Canadian tax laws, a component of the Fund's cash distributions is taxable in the hands of the unitholder, with the remaining portion treated as a return of capital. In addition, a portion of the distribution can take the form of a non-taxable inter-corporate dividend.

Sustainability of Distributions and Productive Capacity

The current level of distributions may change based on the performance of the Fund's businesses, the level of continued investment or the Fund's ability to raise capital. The ECT Board of Trustees periodically approves changes to distributions in accordance with the Fund's distribution practice. Distributable cash flow is defined to generally mean cash from operating, investing and financing activities, less certain items, including repayment of any indebtedness required in the period and any cash withheld as a reserve as determined by the Manager.

The sustainability of the Fund's distributions is a function of several factors: the demand for the services provided by its businesses; the effective maintenance of the productive capacity of its assets; its ability to economically obtain financing to fund growth; operational requirements; its ability to comply with covenants in its debt agreements; and its ability to repay or refinance debt as it comes due.

Each operating segment maintains its productive capacity and ensures the future sustainability of its distributions through regular maintenance programs and periodic maintenance capital expenditures. Maintenance capital expenditures are funded through cash from operations. Refer to the "Capital Expenditures" sections within the Liquidity and Capital Resources section for further discussion on planned maintenance and enhancement capital activities for 2014.

SELECTED ANNUAL FINANCIAL INFORMATION

(millions of Canadian dollars, except where otherwise noted)	**2013**	2012	2011
Revenues[1]	**403.2**	389.6	342.9
Earnings[1]	**79.8**	89.7	144.7
Total assets[1]	**2,756.8**	3,000.4	2,840.8
Total long-term liabilities[1]	**1,777.5**	2,278.5	1,668.2
Cash distributions declared[2]	**221.9**	154.4	112.3
Cash distributions declared per unit (dollars per unit)[2]	**1.612**	1.462	1.392

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions.
2 Includes distributions declared on trust units and Enbridge Commercial Trust preferred units.

Significant items that have impacted the selected annual financial information are as follows:

- 2013 revenues reflect incremental contributions from the start-up of the Bakken Expansion in the first quarter of 2013.
- The decrease in total long-term liabilities in 2013 resulted from $290.0 million in MTNs becoming classified as current liabilities, due to maturity dates in 2014.
- The increase in total long-term liabilities in 2012 resulted from the 2012 Acquisition, which was partly financed with a $582.0 million long-term loan.
- 2012 revenues reflected the first full year of contributions from the Greenwich Wind Project and Amherstburg Solar Project.
- 2011 earnings included $53.8 million of interest income from a $1.0 billion loan from the Crude Oil Storage and Renewable Energy Entities to affiliates of Enbridge that was repaid in 2011 prior to the 2012 Acquisition.

RELATED PARTY TRANSACTIONS

Unless otherwise noted, the following related party transactions are provided in the normal course of business and, unless otherwise noted, measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The 2011 Acquisition and the 2012 Acquisition were accounted for as transactions among entities under common control.

Affiliate Loans

In 2013, ENF advanced $17.5 million (2012 – $6.8 million) to a subsidiary corporation of the Fund pursuant to a subordinated demand loan. At December 31, 2013, $24.3 million (2012 – $6.8 million) was outstanding. Interest on the demand loan was charged at 4.25% per annum. Interest expense on the loan was $0.6 million (2012 – $0.1 million) for the year ended December 31, 2013 and $0.1 million (2012 – $16,278) was included in accounts payable and other as at December 31, 2013.

In December 2012, the Fund received a $582.0 million loan from Enbridge, a related party by virtue of its ECT preferred units and trust unit investment in the Fund, to partially finance the acquisition of Enbridge's interests in the Crude Oil Storage and Renewable Energy Entities. The loan had a 10-year maturity and accrued interest at the rate of 5.0% per annum with interest payable semi-annually in May and November of each year. The loan was repayable at any time in whole or in part, and was unsecured and subordinate to all external debt issued by the Fund. In December 2012, the Fund repaid the loan in full. Interest expense on this loan of $0.5 million was incurred by the Fund for the year ended December 31, 2012, and had been paid in full as at December 31, 2012.

In October 2011, the Fund received a $655.0 million loan from Enbridge to partially finance the acquisition of Enbridge's interests in the Renewable Entities. The loan had a 10-year maturity and accrued interest at the rate of 6.0% per annum with interest payable semi-annually in May and November of each year. The loan was repayable at any time in whole or in part, and was unsecured and subordinate to all external debt issued by the Fund. In December 2011, the Fund repaid $155.0 million of this loan to Enbridge and repaid the remaining balance of $500.0 million in full in February 2012. Interest expense on this loan of $4.4 million (2011 – $7.5 million) was incurred by the Fund for the year ended December 31, 2012, and had been paid in full as at December 31, 2012.

A long-term note receivable from equity investee consists of a promissory note outstanding from Alliance Pipeline Ltd. The balance outstanding at December 31, 2013 and 2012 was $3.7 million. The note is interest bearing and matures in full on December 6, 2015. Interest income earned on this note during each of the years ended December 31, 2013, 2012 and 2011 was $0.4 million.

The Crude Oil Storage and Renewable Energy Entities had borrowed $140.0 million from Enbridge at December 31, 2009. During the year ended December 31, 2012, the loans were repaid in full. Interest accrued on the demand loans at rates varying from 6.8% to 8.1% per annum Interest expense on these loans of $6.4 million (2011 – $10.7 million) was incurred by the Crude Oil and Renewable Energy Entities for the year ended December 31, 2012.

The Crude Oil Storage and Renewable Energy Entities had loaned affiliates of Enbridge $1.6 billion at December 31, 2009. The affiliates repaid $560.0 million during the year ended December 31, 2010 and repaid the remaining balance of $1.0 billion during the year ended December 31, 2011. The loans were due on demand and accrued interest at rates varying from 6.5% to 7.1%. Interest income earned on these loans was $53.8 million for the year ended December 31, 2011.

Green Power

Certain renewable power projects do not have employees and use the services of Enbridge for managing and operating the business. These services totaled $4.2 million for 2013 (2012 – $4.6 million; 2011 – $4.2 million) and included a $1.5 million management fee charged by Enbridge for managing the Ontario Wind Project, Talbot Wind Project and Sarnia Solar Project pursuant to a management agreement. At December 31, 2013, $0.3 million (2012 – $1.6 million) was included in due to affiliates.

The Fund has a contract to sell to Enbridge all available emission reduction credits generated by the Fund's interest in the Chin Chute and Magrath projects. The contract has an initial 20-year term ending October 1, 2026 and provides for a fixed price of $5 per tonne of avoided CO_2 emissions, based on a negotiated rate of converting megawatts generated to tonnes of emissions reduced, plus applicable taxes. The Fund earned $0.2 million (2012 – $0.2 million; 2011 – $0.3 million) for the sale of these emission reduction credits in the year ended December 31, 2013.

One of the Fund's wind power projects, Magrath, has a long-term power price swap, expiring in 2024, with Enbridge Pipelines Inc., a wholly-owned subsidiary of Enbridge. The terms of the agreement are to substantially fix the prices of wind power production. Revenues of $15,695 (2012 – $0.6 million; 2011 – $0.1 million) related to this agreement are reported within the Fund's revenue for the year ended December 31, 2013.

Liquids Transportation and Storage

The Fund does not have any employees and uses the services of Enbridge for managing and operating the businesses comprising the Liquids Transportation and Storage segment. These services, which are charged at cost in accordance with service agreements, were $40.6 million for 2013 (2012 – $35.4 million; 2011 – $29.4 million) of which $5.2 million (2012 – $4.3 million) was included in due to affiliates at December 31, 2013.

The Fund provides certain operational services to Enbridge Pipelines (Bakken) LP, a wholly-owned subsidiary of EEP, an affiliate of the Fund, and charged $1.2 million (2012 – nil) for the year ended December 31, 2013.

The Fund has contracts with shippers who are also affiliates of the Fund through common ownership interests of Enbridge. Revenue from affiliates for the year ended December 31, 2013 was $2.3 million (2012 – $3.5 million; 2011 – $7.3 million) of which $0.1 million was included in accounts receivable and other at December 31, 2013 (2012 – $0.3 million).

Alliance Canada
A subsidiary of Enbridge provides management services to Sable NGL Services L.P. (SNGL Services), a joint venture entity in which the Fund holds a 50% interest. SNGL Services paid management fees of $0.2 million under this agreement during the year ended December 31, 2013 (2012 – $0.1 million; 2011 – $0.3 million). SNGL recorded revenues of $3.6 million (2012 – $3.4 million; 2011 – $3.5 million) and expenses of $5.2 million (2012 – $6.2 million; 2011 – $6.7 million) for natural gas sales and purchases with an affiliate of Enbridge, of which the Fund's interest is 50%.

Alliance Canada has contracts with shippers who are also affiliates of the Fund through common ownership interests of Enbridge,. The Fund's share of Alliance Canada's revenue from affiliates for the year ended December 31, 2013 was $23.2 million (2012 – $23.0 million; 2011 – $21.4 million). The terms of these contracts are the same as those agreed to with independent third parties.

Administrative and operation services are provided by Alliance Canada to Alliance Pipeline US, an entity related to the Fund through common ownership interests. The Fund's share of amounts charged to Alliance Pipeline US during the year ended December 31, 2013 was $21.2 million (2012 – $20.5 million; 2011 – $18.4 million).

Administrative and facility support services are provided by Alliance Canada to Aux Sable Canada LP and Aux Sable Liquid Products LP (the Aux Sable Entities), which are entities related to the Fund through common ownership. The Fund's share of amounts charged to the Aux Sable Entities during the year ended December 31, 2013 was $0.2 million (2012 – $0.1 million; 2011 – $0.3 million).

Corporate
In 2013, the Fund paid $4.1 million (2012 **–** $9.2 million; 2011 **–** $9.2 million) for share issue costs incurred in connection with the offering of 3,820,000 common shares (2012 **–** 9,597,000 subscription receipts; 2011 – 11,707,000 subscription receipts) by ENF. Proceeds from the offerings were used by ENF to purchase additional trust units of the Fund.

Under the management and administrative agreements with EMSI, an incentive fee is payable annually to EMSI based on cash distributions above a base distribution level. During the year ended December 31, 2013, incentive fees were $19.6 million (2012 – $12.4 million; 2011 – $10.4 million), of which, $19.6 million (2012 – $12.4 million) was included in due to affiliates at December 31, 2013. In addition, a base fee of $0.1 million (2012 – $0.1 million; 2011 – $0.1 million) is payable annually for providing administrative and management services and was included in due to affiliates at December 31, 2013.

ECT preferred unit distributions payable to Enbridge of $9.8 million at December 31, 2013 were recorded as distributions payable (2012 – $9.0 million). Trust unit distributions payable to ENF of $7.6 million (2012 – $6.9 million) and to Enbridge of $1.3 million (2012 – $1.3 million) at December 31, 2013 were recorded as distributions payable.

ECT has an agreement with ENF under which it reimbursed ENF $1.0 million (2012 – $1.4 million; 2011 – $0.6 million) for certain general and administrative costs during the year ended December 31, 2013 of which $0.1 million (2012 – $0.4 million) was included in due to affiliates at December 31, 2013.

RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Maintaining a reliable and low risk business model is central to the Fund's objective of paying out a predictable cash flow to unitholders. The Fund actively manages both financial and non-financial risks it is exposed to. The Fund performs an annual corporate risk assessment to identify all potential risks. Risks are ranked based on severity and likelihood both before and after mitigating actions. In addition, the Fund has adopted a Cash Flow at Risk (CFAR) policy to manage exposure to movements in interest rates, foreign exchange rates and commodity prices across all segments. CFAR is a statistically derived measurement that quantifies the maximum adverse impact on cash flows over a specified period of time within a pre-defined level of statistical confidence. The Fund's CFAR limit has been set at 2.5% of forward annual CAFD.

MARKET PRICE RISK

The Fund's earnings, cash flows and other comprehensive income (OCI) are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Fund is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk

The Fund's earnings, cash flows and OCI are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily credit facilities. Floating to fixed interest rate swaps are used to hedge against the effect of future interest rate movements. The Fund has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2017 at an average swap rate of 1.85%.

The Fund's earnings, cash flows and OCI are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps may be used to hedge against the effect of future interest rate movements. At December 31, 2013, $180 million of future fixed rate term debt issuances had been hedged at a swap rate of 4.29% (2012 – nil).

The Fund uses qualifying derivative instruments to manage interest rate risk.

Foreign Exchange Risk

The Fund's earnings, cash flows and OCI are subject to foreign exchange rate variability due to certain United States dollar denominated revenues and expenses. The Fund uses qualifying derivative instruments to manage foreign exchange rate risk.

Commodity Price Risk

The Fund's earnings, cash flows and OCI are exposed to changes in commodity prices due to collection of allowance oil on certain crude oil pipelines, generation of power sold pursuant to floating rate supply agreements, and through commitments to purchase and sell natural gas in connection with capacity held on the Alliance System. The Fund may use crude oil, power and natural gas derivative instruments to fix a portion of the variable price exposures that may arise from these activities. The Fund uses a combination of qualifying and non-qualifying derivative instruments to manage commodity price risk.

Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of cash flow hedges on the Fund's consolidated earnings and comprehensive income.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Interest rate contracts	**0.4**	(2.2)	(7.8)
Foreign exchange contracts	**0.8**	(0.1)	0.1
Commodity contracts	**(0.8)**	8.8	(9.4)
Total unrealized gain/(loss) recognized in OCI	**0.4**	6.5	(17.1)
Amount of gain/(loss) reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**5.1**	3.5	2.0
Foreign exchange contracts[2]	**-**	0.1	0.2
Commodity contracts[3]	**0.5**	(0.5)	0.2
Total gain reclassified from AOCI to earnings *(effective portion)*	**5.6**	3.1	2.4

1 Gain/(loss) reported within Interest expense in the Consolidated Statements of Earnings.
2 Gain/(loss) reported within Other income/(expense) in the Consolidated Statements of Earnings.
3 Gain/(loss) reported within Revenue and Other income/(expense) in the Consolidated Statements of Earnings.

Non-Qualifying Derivatives
The following table presents the unrealized gains and losses associated with changes in the fair value of the Fund's non-qualifying derivatives.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Commodity contracts[1]	**0.1**	(0.1)	-
Total unrealized derivative fair value gain/(loss)	**0.1**	(0.1)	-

1 Gain/(loss) reported within Revenue in the Consolidated Statements of Earnings.

LIQUIDITY RISK
Liquidity risk is the risk that the Fund will not be able to meet its financial obligations, including commitments, as they become due. In order to manage this risk, the Fund forecasts the cash requirements over the near and long term to determine whether sufficient funds will be available when required. The Fund's primary sources of liquidity and capital resources are funds generated from operations, draws under committed credit facilities and the issuance of medium term notes. The Fund maintains a current shelf prospectus with Canadian securities regulators, which subject to market conditions, enables ready access to Canadian public capital markets. Cash flow from operations, in combination with available committed credit facilities and capital markets funding, if required, is expected to be sufficient to meet the forecast liquidity and capital resource requirements of the Fund.

CREDIT RISK
Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Fund enters into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits, contractual requirements and frequent assessment of counterparty credit worthiness.

Credit risk also arises from trade and other receivables, and is mitigated through credit exposure limits and by requiring less creditworthy counterparties to provide credit enhancement which may include letters of credit, posting of collateral, netting provisions or other contractual requirements. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

The Fund uses the most observable inputs available to estimate the fair value of its financial instruments. When possible, the Fund estimates the fair value of its financial instruments based on quoted market prices. If quoted market prices are not available, the Fund uses estimates from third party brokers. For non-exchange traded derivatives, the Fund uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of financial instrument and nature of the underlying risk, the Fund uses observable market prices (interest, foreign exchange and commodity) and volatility as primary inputs to these valuation techniques. Finally, the Fund considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

NON-FINANCIAL RISKS

Regulation and Legislation

Earnings and expansion projects on the Saskatchewan System and Alliance Canada are subject to the actions of various regulators, including the NEB. Actions of the regulators related to tariffs, tolls and facilities impact earnings and the success of expansion projects. Delays in regulatory approvals could result in cost escalations and construction delays.

Changes in regulation, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could adversely affect the results of operations of the Fund's businesses. Further, the nature and degree of regulation and legislation affecting energy companies in Canada has changed significantly in past years and there is no assurance that further substantial changes will not occur. Such regulations and legislation may adversely affect the toll structure or other aspects of the Fund's business or the operations and creditworthiness of counterparties.

Supply and Demand

The operation of the Fund's liquids and natural gas pipelines and storage assets is dependent upon the supply of and demand for crude oil and natural gas from Western Canada. The demand for crude oil by refiners is dependent upon a number of factors including the price of crude oil, the cost of operating the refinery and market prices for the various refined products. Demand for natural gas is affected among other things, by weather, requirements for electric power and broader levels of economic activity. Supply of crude oil and natural gas is dependent upon a number of variables, including:

- the level of exploration, drilling, reserves, and production of crude oil and natural gas;
- the accessibility of Western Canadian crude oil and natural gas;
- the price and quality of crude oil and natural gas available from alternative Canadian and United States sources; and
- the regulatory environments in Canada and the United States, including the continued willingness of the governments of both countries to permit the export of crude oil and natural gas from Canada to the United States on a commercially acceptable basis.

Supply and demand risk on Alliance Canada is mitigated by long-term TSAs under which substantially all of Alliance Canada's firm transportation capacity is contracted through 2015. Subsequent to 2015, demand for Alliance Canada's transportation services will be dependent upon the competitiveness of its tolls relative to alternative pipelines, the netbacks received by its shippers relative to pipelines to other markets, the geographic location of its assets relative to natural gas production, the ability of its proposed new service offering to meet shipper requirements and to gain regulatory approvals.

Demand for the Fund's services is also affected by the supply of and demand for power generated by facilities within the Green Power segment. This risk is mitigated by the long-term PPAs entered into with customers.

Operating Risk
The operation of Green Power, Liquids Transportation and Storage and Alliance Canada involves risks, including the failure of equipment, information systems or processes, poor performance of equipment (whether due to misuse, unexpected degradation or design, construction or manufacturing defects), lack of spare parts, operator error, failure of internal controls, non-compliance with legal or other obligations, labour disputes, disputes or issues with interconnected facilities and carriers and catastrophic events such as natural disasters, fires, explosions, fractures, acts of terrorists and saboteurs, occurrence of a pandemic and other similar events, many of which are beyond the control of the respective systems. The occurrence or continuance of any of these events could increase the cost of operating Green Power, Liquids Transportation and Storage, and Alliance Canada, reduce transportation or generation capacity, thereby potentially impacting cash flow. The Fund employs various inspection and monitoring methods to manage pipeline, turbine, solar panels and facility integrity as well as to minimize system disruptions. Additionally, the Fund maintains safety policies, disaster recovery procedures and insurance coverage at industry acceptable levels in the case of an incident.

The Fund and its operating affiliates have extensive programs to manage system integrity, which includes the development and use of in-line inspection tools. Maintenance, excavation and repair programs are directed to the areas of greatest benefit and pipe is replaced or repaired as required. The Fund also has a security program designed to reduce security-related risks.

The Fund participates in a comprehensive insurance program maintained by Enbridge. The program includes commercial liability insurance coverage and coverage for environmental incidents, taking into account coverage levels considered customary for its industry and the insurance market at the time of renewal. In the event multiple insurable incidents exceeding coverage limits are experienced among insured entities within the same insurance period, the total insurance coverage will be allocated pursuant to a pre-determined formula. As a result, the comprehensive insurance program may not be sufficient to cover all losses experienced by the Fund.

Environmental Costs and Liabilities
The operation of Green Power, Liquids Transportation and Storage and Alliance Canada are subject to federal, provincial and local laws and regulations relating to environmental protection and operational safety. Risks of substantial environmental costs and liabilities, including those from leaks and explosions, are inherent in pipeline operations and there can be no assurance that significant costs and liabilities, including those relating to claims for damages to property and persons resulting from operations of Green Power, Alliance Canada and/or Liquids Transportation and Storage, will not be incurred. To mitigate this risk, Green Power, Alliance Canada and Liquids Transportation and Storage have established safety and environmental policies that are designed to ensure that their operations comply with existing regulations relating to personal safety and protection of the environment. It is not possible to predict the effect that any future changes in environmental laws and regulations will have on future earnings and there can be no assurance that environmental costs incurred by Green Power, Alliance Canada or Liquids Transportation and Storage will be partially or fully recoverable.

Credit Risk
Fixed price revenues from the Fund’s renewable power generation facilities are received from a small number of counterparties. The stability of the Fund's revenue and cash flows from this segment is dependent upon the ability of counterparties to pay their monthly charges. If a counterparty is unable to fulfill their obligations under their purchase agreements and an alternate counterparty is not available, Green Power would be exposed to variable power prices. This risk has been mitigated through contracting with strong investment grade counterparties.

Liquids Transportation and Storage’s trade receivables consist primarily of amounts due from companies that produce or market crude oil and natural gas liquids. The credit risk associated with these receivables is mitigated by utilization of credit exposure limits where appropriate, and requiring less creditworthy customers to provide credit enhancement which may include letters of credit, posting of collateral, netting provisions or other contractual requirements.

Currently, approximately 11% of firm capacity on Alliance Canada's system is contracted to shippers who do not have an investment grade rating or equivalent strong credit status and are required to post security. Although such shippers have provided security to Alliance Canada, it is only sufficient to fully cover one year of demand charges under the TSAs. There can be no assurance that the security will be adequate to compensate Alliance Canada if a shipper is unable to fulfill its obligations under its TSA or unable to recontract with another party.

Project Execution
The Fund's ability to successfully execute the development of its organic growth projects may be influenced by capital constraints, third-party opposition, changes in shipper support for projects over time, delays in or changes to government and regulatory approvals, cost escalations, construction delays, inadequate resources, in-service delays and increasing complexity of projects (collectively, Execution Risk). Early stage project risks include right-of-way procurement, special interest group opposition, Crown consultation, and environmental and regulatory permitting. Cost escalations or missed in-service dates on future projects may impact future earnings. Construction delays due to regulatory delays, contractor or supplier non-performance and weather conditions may impact project development.

To mitigate these risks, clearly defined management and governance structures for all major projects are established and strategic relationships with landowners, suppliers, contractors and other stakeholders are formed and maintained. Additionally, Enbridge, the Fund's Manager and the Fund's joint venture interests ensure that compensation programs, communications and working environments are designed to attract, develop and retain qualified personnel.

Special Interest Groups
The Fund is exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on governments and regulators by special interest groups including aboriginal groups, landowners and non-governmental organizations. Recent Supreme Court decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. In The Fund and its contractors work proactively with special interest groups to identify and develop appropriate responses to concerns regarding its projects.

Joint Venture Partners
Certain of the Fund's businesses consist of joint venture partnerships with the Fund's ownership interests ranging from 33% to 50%. In these joint ventures, the Fund does not have full control to execute initiatives without consent from the joint venture partners. This risk is mitigated through formal governance procedures as well as ongoing dialogue with joint venture partners.

CRITICAL ACCOUNTING ESTIMATES

Depreciation

Depreciation of property, plant and equipment, the Fund's largest asset with a net book value of $2,317.1 million at December 31, 2013, is generally provided on either a straight-line basis over the estimated service lives of the assets or a unit of throughput basis commencing when the asset is placed in service. When it is determined that the estimated service life of an asset does not reflect the expected remaining period of benefit, prospective changes are made to the estimated service life. In general, estimates of service lives are based on third party engineering studies, experience and industry practice. There are a number of assumptions inherent in estimating the service lives of the Fund's assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by the Fund's pipelines as well as the demand for crude oil and natural gas and the integrity of the Fund's systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of the Fund's operating segments.

Regulation
Both Alliance Canada and the systems comprising the Saskatchewan System are subject to regulation by various authorities, including the NEB, Saskatchewan Ministry of Economy and Manitoba Innovation, Energy and Mines. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for entities that are not rate-regulated.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in deferred amounts and other assets and current regulatory assets are recorded in accounts receivable and other. Long-term regulatory liabilities are recorded in other long-term liabilities and current regulatory liabilities are recorded in accounts payable and other. Regulatory assets are assessed for impairment if the Fund identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions or expected future actions of the regulator. To the extent that the regulator's actions differ from the Fund's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Fund would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. The Settlement relating to new tolls on the Westspur System resulted in the discontinuance of rate regulated accounting for the Westspur System during the year ended December 31, 2013, and the Liquids Transportation and Storage segment recorded a pre-tax write-off of $16.5 million related to previously-recorded deferred revenue which will not be collected under the terms of the Settlement. As at December 31, 2013, the Fund's net regulatory assets totalled $60.9 million (December 31, 2012 – $72.9 million).

Asset Retirement Obligations
Asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized and measured at fair value when they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Fund's estimates of retirement costs could change as a result of changes in timing and cost estimates as well as changes in regulatory requirements.

In May 2009, the NEB released a report on the financial issues associated with pipeline abandonment and established a goal for pipelines regulated under the NEB Act to begin collecting and setting aside funds to cover future abandonment costs no later than January 1, 2015. Since then, the NEB has issued revised "base case assumptions" based on feedback from member companies. Companies have the option to follow the base case assumptions or to submit pipeline specific applications.

On February 28, 2013, Group 1 pipeline companies, which include Alliance Canada, filed a proposed process and mechanism to set aside the funds for future abandonment costs and chose the trust as the appropriate set-aside mechanism to hold pipeline abandonment funds. On May 31, 2013, the Group 1 companies filed collection mechanism applications, and the Group 2 companies, which include certain pipelines in the Saskatchewan System, filed both their set-aside and collection mechanism applications. Once the set aside and collection mechanism is approved by the NEB, both Group 1 and Group 2 companies can start to recover these costs from shippers through tolls in accordance with the NEB's determination that abandonment costs are a legitimate cost of providing service and are recoverable upon NEB approval from users of the system. The collections are expected to begin in 2015.

All applications by the Fund will require NEB approval. The NEB has set a hearing, covering both the set-aside mechanism applications and the collection mechanism applications for both Group 1 and Group 2 companies. The hearing commenced January 14, 2014 with the decision expected in the second quarter of 2014.

Currently, for certain of the Fund's assets, there is insufficient data or information to reasonably determine the timing of a settlement for estimating the fair value of the asset retirement obligation (ARO). In such cases, the ARO cost is considered indeterminate for accounting purposes as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

CHANGES IN ACCOUNTING POLICIES

Balance Sheet Offsetting

Effective January 1, 2013, the Fund adopted Accounting Standards Updates (ASUs) 2011-11 and 2013-01, which require enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. As the adoption of these updates impacted disclosure only, there was no impact to the Fund's consolidated financial position for the current or prior periods presented.

Accumulated Other Comprehensive Income

Effective January 1, 2013, the Fund adopted ASU 2013-02, which requires enhanced disclosures on amounts reclassified out of accumulated other comprehensive income (AOCI). As the adoption of this update impacted disclosure only, there was no impact to the Fund's presentation of comprehensive income or the Fund's consolidated financial statements for the current or prior periods presented.

Presentation of Unrecognized Tax Benefits

Effective December 31, 2013, the Fund elected to early adopt ASU 2013-11, which requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. There was no impact to the Fund's consolidated financial statements for the current or prior periods presented as a result of adopting this update.

Future Accounting Policy Changes

Obligations Resulting from Joint and Several Liability Arrangements

ASU 2013-04 was issued in February 2013 and provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. The adoption of the pronouncement is not anticipated to have a material impact on the Fund's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively.

SELECTED QUARTERLY FINANCIAL INFORMATION

	2013				2012			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
(millions of Canadian dollars)								
Revenue[1]	**103.7**	92.5	104.4	102.6	93.8	91.2	101.2	103.4
Earnings[1]	**22.1**	16.9	27.2	13.6	16.6	20.5	25.5	27.1
Cash distributions declared[2]	**56.1**	55.7	55.7	54.4	42.2	37.4	37.4	37.4

1 Revenue and earnings have been retrospectively adjusted to furnish comparative information related to the 2012 Acquisition as prescribed by U.S. GAAP for common control transactions.
2 Cash distributions declared on trust units and ECT preferred units.

Significant items that have impacted quarterly financial information are as follows:

- The Bakken Expansion commenced operations in the first quarter of 2013, resulting in an increase in revenues and earnings.
- First quarter 2013 earnings were impacted by a regulatory asset write-off of $12.0 million after tax related to the discontinuance of rate regulated accounting for the Westspur System.
- The Fund increased its monthly distribution per unit to $0.135 effective with the November 2013 distribution.
- The Fund issued 4,768,000 trust units and ECT issued 5,232,000 preferred units in February 2013. The proceeds were used to repay debt used to fund capital expenditures and to partially fund ongoing capital expenditures associated with the Fund's organic expansion strategy.
- The Fund issued 11,982,000 trust units and ECT issued 13,159,000 preferred units in December 2012 in connection with the 2012 Acquisition. Incremental cash flow from the acquisition enabled the Fund to increase the monthly distribution per unit to $0.134 effective with the December 2012 distribution. The increase in units outstanding and the increase in the amount of the monthly distribution per unit resulted in a corresponding increase in cash distributions declared.
- The Fund issued 14,616,000 trust units and ECT issued 16,051,000 preferred units in October 2011 in connection with the 2011 Acquisition. Incremental cash flows generated by the acquired assets enabled the Fund to increase the monthly distribution per unit to $0.121 effective with the November 2011 distribution. The increase in units outstanding and the increase in the amount of the monthly distribution per unit resulted in a corresponding increase in cash distributions declared.
- Revenues and earnings generated by the Green Power segment are subject to seasonal variations. This is driven by stronger wind resources in the first and fourth quarters and stronger solar resources in the second and third quarters. Although these trends are offsetting, revenues and earnings are generally expected to be lowest in the third quarter, attributable to seasonally weaker wind resources.

ENBRIDGE INCOME FUND

CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2013

February 10, 2014

Independent Auditor's Report

To the Unitholders of
Enbridge Income Fund

We have audited the accompanying consolidated financial statements of Enbridge Income Fund, which comprise the consolidated statements of financial position as at December 31, 2013 and December 31, 2012 and the consolidated statements of earnings, comprehensive income, unitholders' equity and cash flows for each of the three years in the period ended December 31, 2013, and the related notes, which comprise 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 accounting principles generally accepted in the United States of America, 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.

Auditor's 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 the 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 the auditor's 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, the auditor considers 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.

PricewaterhouseCoopers LLP
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Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enbridge Income Fund as at December 31, 2013 and December 31, 2012 and its operations and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

Chartered Accountants

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Revenues			
Transportation and other services	**214.7**	199.3	191.2
Electricity sales	**188.5**	190.3	151.7
	403.2	389.6	342.9
Expenses			
Operating and maintenance	**113.4**	100.0	83.2
Management and administrative	**21.8**	19.3	16.7
Depreciation and amortization	**129.7**	122.1	113.4
	264.9	241.4	213.3
	138.3	148.2	129.6
Income from equity investments *(Note 10)*	**55.9**	53.8	52.7
Other income/(expense) *(Note 19)*	**(0.4)**	0.7	54.6
Interest expense *(Note 14)*	**(73.6)**	(62.4)	(42.5)
	120.2	140.3	194.4
Income taxes *(Note 21)*	**(28.4)**	(50.6)	(49.7)
Earnings before extraordinary item	**91.8**	89.7	144.7
Extraordinary loss, net of tax *(Note 24)*	**(12.0)**	-	-
Earnings	**79.8**	89.7	144.7

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.
2 The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Earnings	**79.8**	89.7	144.7
Other comprehensive income/(loss)			
Change in unrealized gain/(loss) on cash flow hedges, net of tax[2]	**0.4**	4.8	(14.7)
Reclassification of cash flow hedges to earnings, net of tax[3]	**5.5**	3.1	4.7
Other comprehensive income/(loss)	**5.9**	7.9	(10.0)
Comprehensive income	**85.7**	97.6	134.7

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.
2 Tax expense/(recovery) was nil (2012 – $1.7 million; 2011 - $(2.4) million) for the year ended December 31, 2013.
3 Tax expense was $0.1 (2012 – nil; 2011 – nil) for the year ended December 31, 2013.
4 The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN UNITHOLDERS' EQUITY

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Retained earnings (deficit)			
Balance at beginning of year	**(2,631.5)**	(1,026.3)	1,367.3
Earnings	**79.8**	89.7	144.7
ECT preferred unit distributions	**(116.1)**	(80.8)	(58.8)
Distributions to trust unitholders	**(105.8)**	(73.6)	(53.5)
Redemption value adjustment attributable to ECT preferred units *(Note 16)*	**66.9**	(230.8)	(97.7)
Redemption value adjustment attributable to trust units *(Note 17)*	**56.8**	(219.4)	(98.2)
Excess purchase price over net assets acquired *(Note 7)*	**5.3**	(286.5)	(287.8)
Equity of former owners of acquired entities *(Note 7)*	**-**	(803.8)	(1,942.3)
Balance at end of year	**(2,644.6)**	(2,631.5)	(1,026.3)
Accumulated other comprehensive loss			
Balance at beginning of year	**(23.4)**	(31.3)	(21.3)
Other comprehensive income/(loss), net of tax	**5.9**	7.9	(10.0)
Balance at end of year	**(17.5)**	(23.4)	(31.3)
Total unitholders' deficit	**(2,662.1)**	(2,654.9)	(1,057.6)

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.
2 The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Operating activities			
Earnings	**79.8**	89.7	144.7
Charges/(credits) not affecting cash			
Depreciation and amortization	**129.7**	122.1	113.4
Cash distributions in excess of equity earnings	**14.2**	18.3	21.0
Deferred income taxes *(Note 21)*	**27.3**	55.0	47.0
Regulatory asset write-off, net of tax *(Note 24)*	**12.0**	-	-
Other	**10.9**	5.0	4.8
Changes in operating assets and liabilities *(Note 20)*	**(13.8)**	(23.4)	7.6
	260.1	266.7	338.5
Investing activities			
Additions to property, plant and equipment	**(76.0)**	(150.8)	(338.9)
Contributions to equity investees	**(21.1)**	(16.5)	(5.0)
Additions to intangible assets	**(0.8)**	(0.5)	(8.9)
Proceeds from disposition of property, plant and equipment	**-**	1.8	-
Loans to affiliates *(Note 22)*	**-**	-	1,045.0
Acquisitions *(Note 7)*	**5.3**	(1,168.0)	(1,241.2)
	(92.6)	(1,334.0)	(549.0)
Financing activities			
Net change in bank indebtedness	**(160.5)**	129.0	28.0
Net change in credit facility draws	**(210.6)**	(10.0)	130.0
Issuance of medium term notes, net	**-**	1,194.1	123.1
ECT preferred units issued (*Note 16)*	**130.8**	304.6	301.0
Trust units issued, net (*Note 17)*	**115.1**	268.2	264.8
ECT preferred unit distributions declared	**(116.1)**	(80.8)	(58.8)
Trust unit distributions declared	**(105.8)**	(73.6)	(53.5)
Change in distributions payable	**1.5**	4.7	9.2
Loans from affiliates *(Note 22)*	**17.5**	588.8	655.0
Repayment of affiliate loans *(Note 22)*	**-**	(1,222.0)	(163.0)
Contributions received and shares issued by Acquired Entities *(Note 7)*	**-**	148.5	227.4
Distributions and dividends paid by Acquired Entities *(Note 7)*	**-**	(68.2)	(185.8)
Return of stated capital of common shares of Acquired Entities *(Note 7)*	**-**	-	(1,038.1)
	(328.1)	1,183.3	239.3
Increase in cash and cash equivalents	**(160.6)**	116.0	28.8
Cash and cash equivalents at beginning of year	**189.6**	73.6	44.8
Cash and cash equivalents at end of year	**29.0**	189.6	73.6
Supplementary cash flow information			
Income taxes paid	**0.6**	4.8	-
Interest paid	**64.0**	56.0	30.2

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.
2 The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	**2013**	2012[1]
(millions of Canadian dollars)		
Assets		
Current assets		
Cash and cash equivalents	**29.0**	189.6
Accounts receivable and other, net *(Note 8)*	**56.3**	46.8
Deferred income taxes *(Note 21)*	**4.0**	16.7
	89.3	253.1
Property, plant and equipment, net *(Note 9)*	**2,317.1**	2,389.5
Long-term investments *(Note 10)*	**219.5**	212.6
Deferred amounts and other assets *(Note 11)*	**70.2**	83.1
Intangible assets *(Note 12)*	**27.5**	28.9
Goodwill	**28.8**	28.8
Long-term note receivable from equity investee *(Note 22)*	**3.7**	3.7
Deferred income taxes *(Note 21)*	**0.7**	0.7
	2,756.8	3,000.4
Liabilities and unitholders' equity		
Current liabilities		
Bank indebtedness	**6.3**	166.8
Accounts payable and other *(Note 13)*	**54.8**	63.4
Due to affiliates *(Note 22)*	**49.8**	29.8
Distributions payable *(Note 22)*	**18.7**	17.2
Current maturities of long-term debt *(Note 14)*	**290.0**	-
	419.6	277.2
Long-term debt *(Note 14)*	**1,364.2**	1,864.2
Other long-term liabilities *(Note 15)*	**23.0**	22.9
Deferred income taxes *(Note 21)*	**390.3**	391.4
	2,197.1	2,555.7
Commitments and contingencies *(Note 23)*		
ECT preferred units *(Note 16)*	**1,686.2**	1,622.3
Trust units *(Note 17)*	**1,535.6**	1,477.3
	3,221.8	3,099.6
Unitholders' deficit		
Deficit	**(2,644.6)**	(2,631.5)
Accumulated other comprehensive loss	**(17.5)**	(23.4)
	(2,662.1)	(2,654.9)
	2,756.8	3,000.4

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.
2 The accompanying notes are an integral part of these consolidated financial statements.

Approved by the Trustees of Enbridge Commercial Trust on behalf of Enbridge Income Fund:

"signed"
E.F.H. Roberts
Trustee

"signed"
Gordon G. Tallman
Trustee

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL BUSINESS DESCRIPTION

Enbridge Income Fund (the Fund) is an unincorporated open-ended trust established by a trust indenture under the laws of the Province of Alberta. The Fund commenced operations on June 30, 2003. Enbridge Management Services Inc. (EMSI), a wholly-owned subsidiary of Enbridge Inc. (Enbridge), administers the Fund. EMSI also serves as the manager of Enbridge Commercial Trust (ECT), a subsidiary of the Fund, and Enbridge Income Fund Holdings Inc. (ENF), a unitholder of the Fund.

In December 2010, pursuant to the court approved plan of arrangement (the Plan), all publicly held trust units of the Fund, as well as 5,000,000 trust units held by Enbridge, were exchanged on a one-for-one basis for shares of a taxable Canadian corporation, ENF. The trust units ceased trading on the Toronto Stock Exchange and the ENF shares were listed. Subsequent to implementation of the Plan, the Fund ceased to be a specified investment flow-through (SIFT) entity and therefore is not subject to SIFT tax legislation.

The Fund conducts its business through three operating segments: Green Power, Liquids Transportation and Storage and Alliance Canada. These segments are strategic business units established along service lines by management to assess operational performance and to achieve the Fund's long-term objectives.

GREEN POWER
Green Power includes the Ontario Wind Project, the Talbot Wind Project, the Greenwich Wind Project, the Sarnia Solar Project, the Amherstburg Solar Project and the Tilbury Solar Project. Green Power also includes the Fund's 33% to 50% interests in three wind power projects in Saskatchewan and southern Alberta and the Fund's 50% interest in NRGreen, which operates waste heat recovery power generation facilities along the Alliance System.

LIQUIDS TRANSPORTATION AND STORAGE
The Liquids Transportation and Storage segment includes the Saskatchewan System crude oil and liquids pipeline system which connects to the Enbridge mainline at Cromer, Manitoba, as well as liquids storage assets in both Saskatchewan and Alberta. The Saskatchewan System includes five crude oil and liquids pipeline systems: Saskatchewan Gathering, Westspur, Weyburn, Virden and Bakken Expansion. Storage assets include terminals and tankage facilities in Saskatchewan, as well as the Hardisty Contract Terminals and Hardisty Storage Caverns located in Hardisty, Alberta.

ALLIANCE CANADA
Alliance Canada consists of the Fund's 50% interest in the Canadian portion of the 3,000 km Alliance System. The Alliance System, comprised of Alliance Canada and Alliance US, transports natural gas primarily from supply areas in northwestern Alberta and northeastern British Columbia to delivery points near Chicago, Illinois.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Fund have been prepared in accordance with United States generally accepted accounting principles (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted.

The Fund commenced reporting using U.S. GAAP as its primary basis of accounting effective January 1, 2012, including restatement of comparative periods. The Fund is permitted to use U.S. GAAP as its primary basis of accounting for purposes of meeting its continuous disclosure obligations under an exemption granted by securities regulators in Canada.

BASIS OF PRESENTATION AND USE OF ESTIMATES

On December 10, 2012, the Fund acquired 100% interests in the following entities which were wholly-owned by Enbridge or subsidiaries of Enbridge: Enbridge Midstream Inc., Hardisty Caverns Ltd., Hardisty Caverns Limited Partnership, Greenwich Windfarm GP Inc., Greenwich Windfarm, LP, Tilbury Solar Project LP, 7243341 Canada Inc., Project AMBG2 Inc. and Project AMBG2 LP (collectively the Crude Oil Storage and Renewable Energy Entities).

On October 21, 2011, the Fund acquired 100% interests in the following entities which were wholly-owned by subsidiaries of Enbridge: Talbot Windfarm LP, Talbot Windfarm GP Inc., Enbridge Renewable Energy Infrastructure Canada Inc., 1682399 Ontario Corp., Enbridge Renewable Energy Infrastructure Limited Partnership (ERIP) and ERIP's wholly-owned subsidiary, Ontario Sustainable Farms Inc. (collectively the Renewable Entities).

The acquisitions of the Renewable Entities and the Crude Oil Storage and Renewable Energy Entities (collectively, the Acquired Entities) were accounted for as transactions among entities under common control, similar to a pooling of interests, whereby the assets and liabilities acquired were recorded at Enbridge's historic carrying values. Earnings for the years ended December 31, 2012 and 2011 report the results of operations of the Acquired Entities as though the acquisitions occurred at the beginning of the year acquired. Similarly, comparative information for prior years has been retrospectively adjusted to present the results of operations for the Fund and the Acquired Entities on a combined basis. See Note 7 for additional disclosure regarding the acquisition of the Acquired Entities.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities *(Note 6)*; depreciation rates and carrying value of property, plant and equipment *(Note 9)*; measurement of and amortization rates of intangible assets *(Note 12)*; measurement of goodwill *(Note 7)*; fair values of financial instruments *(Note 18)*; income taxes *(Note 21)*; and fair value of asset retirement obligations *(Note 15)*. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Fund and its subsidiaries. All significant intercompany accounts and transactions are eliminated upon consolidation. Investments and entities over which the Fund exercises significant influence are accounted for using the equity method. The consolidated financial statements have been retrospectively adjusted to furnish comparative information related to the acquisition of the Acquired Entities.

REGULATION

Both Alliance Canada and the systems comprising the Saskatchewan System are subject to regulation by various authorities, including the National Energy Board (NEB), Saskatchewan Ministry of Economy (SME) and Manitoba Innovation, Energy and Mines. Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under U.S. GAAP for entities not subject to rate regulation.

Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates. Long-term regulatory assets are recorded in deferred amounts and other assets and current regulatory assets are recorded in accounts receivable and other. Long-term regulatory liabilities are recorded in other long-term liabilities and current regulatory liabilities are recorded in accounts payable and other. Regulatory assets are assessed for impairment if the Fund identifies an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions of the regulator. To the extent that the regulator's actions differ from the Fund's expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, the Fund would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned.

Allowance for Funds Used During Construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component. In the absence of rate regulation, the Fund would capitalize interest using a capitalization rate based on its cost of borrowing and the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

REVENUE RECOGNITION

For businesses which are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer credit worthiness is assessed prior to agreement signing as well as throughout the contract duration.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts ratably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. The Fund recognizes revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are primarily used to economically hedge commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings, in revenues and other income/(expense).

Derivatives in Qualifying Hedging Relationships

The Fund uses derivative financial instruments to manage exposure to changes in interest rates, commodity prices and foreign exchange rates. Hedge accounting is optional and requires the Fund to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in the fair values or cash flows of the underlying hedged item on an ongoing basis. The Fund presents the earnings and cash flow effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges or fair value hedges. There were no fair value hedges outstanding at December 31, 2013 and 2012.

Cash Flow Hedges

The Fund uses cash flow hedges to manage exposure to changes in interest rates, commodity prices and foreign exchange rates. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in other comprehensive income (OCI) and reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from ineffective derivative instruments are recognized in earnings in the period in which they occur.

Classification of Derivatives

The Fund recognizes the fair market value of derivative instruments on the statement of financial position as current and long-term assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. The fair value related to cash flows occurring within one year are classified as current, and the fair value related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when the Fund has a legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. The Fund incurs transaction costs primarily through the issuance of debt and classifies these costs with deferred amounts and other assets. These costs are amortized using the effective interest rate method over the life of the related debt instrument.

INCOME TAXES
Pursuant to the *Income Tax Act* (Canada), the Fund and ECT, as trusts, are not subject to income taxes to the extent that taxable income and taxable capital gains are paid or payable to unitholders. However, certain subsidiary corporations are taxable and applicable income taxes have been reflected in these consolidated financial statements.

The liability method of accounting for income taxes is followed for subsidiary corporations. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying value for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For the Fund's regulated operations, a deferred income tax liability is recognized with a corresponding regulatory asset. Interest and penalties related to tax are reflected in interest expense.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

INVENTORY
Crude oil inventory on the Saskatchewan System is accumulated as a part of the tolls for transportation on certain pipeline systems. Any excess volumes of inventory collected and sold over and above measurement losses (saleable inventory) is recognized as Transportation and other services revenue in the Consolidated Statements of Earnings. Remaining saleable inventory is recorded at the lower of cost or market value.

INVESTMENTS IN UNCONSOLIDATED AFFILIATES
Equity investments over which the Fund exercises significant influence but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Fund's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. The Fund capitalizes interest incurred during construction.

Two primary methods of depreciation are utilized. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting for property, plant and equipment is followed whereby similar assets are grouped and depreciated as a pool. When those assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation. Certain pipeline assets in service within the Saskatchewan System are depreciated based on unit of throughput.

INTANGIBLE ASSETS
Intangible assets consist primarily of acquired power production and incentive agreements for wind and solar projects and computer software. The Fund capitalizes costs incurred during the application development stage of internal use software projects. Intangible assets are amortized on a straight-line basis over their expected lives.

GOODWILL
Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. The Fund has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step involves determining the fair value of the Fund's reporting units inclusive of goodwill and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill based on the fair value of the reporting unit's assets and liabilities.

IMPAIRMENT
The Fund reviews the carrying values of its long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, the asset is written down to fair value.

With respect to equity investments, the Fund assesses at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is determined to be objective evidence of impairment, the Fund internally values the expected discounted cash flows using observable market inputs and determines whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

The Fund assesses financial assets for impairment when it no longer has a reasonable assurance of timely collection. If evidence of impairment is noted, the Fund reduces the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; derivative financial instruments; as well as deferred financing costs. Deferred financing costs are amortized using the effective interest method over the term of the related debt.

ASSET RETIREMENT OBLIGATIONS
Asset retirement obligations (AROs) associated with the retirement of long-lived assets are recognized and measured at fair value when they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. AROs are added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. The Fund's estimates of retirement costs could change as a result of changes in timing and cost estimates as well as changes in regulatory requirements.

For certain of the Fund's assets, it is not possible to make a reasonable estimate of AROs due to the indeterminate timing and scope of the asset retirements.

REDEEMABLE SECURITIES
At December 31, 2013, 2012 and 2011, ECT preferred units and trust units are classified as temporary equity and reflected within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and unitholders' deficit. ECT preferred units and trust units are recorded at their maximum redemption value with changes in estimated redemption value reflected as a charge or credit to deficit.

3. CHANGES IN ACCOUNTING POLICIES

BALANCE SHEET OFFSETTING

Effective January 1, 2013, the Fund adopted Accounting Standards Updates (ASUs) 2011-11 and 2013-01, which require enhanced disclosures on the effect or potential effect of netting arrangements on an entity's financial position. As the adoption of these updates impacted disclosure only, there was no impact to the Fund's consolidated financial position for the current or prior periods presented.

ACCUMULATED OTHER COMPREHENSIVE INCOME

Effective January 1, 2013, the Fund adopted ASU 2013-02, which requires enhanced disclosures on amounts reclassified out of accumulated other comprehensive income (AOCI). As the adoption of this update impacted disclosure only, there was no impact to the Fund's presentation of comprehensive income or the Fund's consolidated financial statements for the current or prior periods presented.

PRESENTATION OF UNRECOGNIZED TAX BENEFITS

Effective December 31, 2013, the Fund elected to early adopt ASU 2013-11, which requires presentation of unrecognized tax benefits as a reduction to a deferred tax asset for a net operating loss carryforward unless specific conditions exist. There was no impact to the Fund's consolidated financial statements for the current or prior periods presented as a result of adopting this update.

FUTURE ACCOUNTING POLICY CHANGES

Obligations Resulting from Joint and Several Liability Arrangements

ASU 2013-04 was issued in February 2013 and provides both measurement and disclosure guidance for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. The adoption of the pronouncement is not anticipated to have a material impact on the Fund's consolidated financial statements. This accounting update is effective for annual and interim periods beginning after December 15, 2013 and is to be applied retrospectively.

4. REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In connection with the preparation of the Fund's consolidated financial statements for the three months ended March 31, 2013, an error was identified in the manner in which the Fund's investee, Alliance Canada, recorded a deferred regulatory asset associated with the difference between depreciation expense calculated in accordance with U.S. GAAP and negotiated depreciation rates recovered in transportation tolls. This resulted in an overstatement of the Fund's carrying value of its investment in Alliance Canada. Further, a deferred income tax liability and an offsetting regulatory asset was recognized by the Fund related to the carrying value of its investment. In accordance with accounting guidance found in ASC 250-10 (SEC Staff Accounting Bulletin No. 99, Materiality) the Fund assessed the error and concluded that the related amount was not material to any of its previously issued consolidated financial statements. In accordance with guidance found in ASC 250-10 (SEC Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements), the Fund revised its previously issued consolidated financial statements to correct the effect of this error. The effects which flow through to the Consolidated Statements of Cash Flows are not significant and have no effect on the Fund's cash flows from operating activities.

Comparative figures as at December 31, 2012 and for the years ended December 31, 2012 and 2011 have been revised throughout these financial statements as necessary to reflect these revisions.

	Year ended December 31, 2012			Year ended December 31, 2011		
	As Previously Reported	Adjustment	As Revised	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)						
Income from equity investments	51.9	1.9	53.8	55.5	(2.8)	52.7
Earnings	87.8	1.9	89.7	147.5	(2.8)	144.7

	As at December 31, 2012		
	As Previously Reported	Adjustment	As Revised
(millions of Canadian dollars)			
Long-term investments	311.3	(98.7)	212.6
Deferred amounts and other assets	116.7	(33.6)	83.1
Deferred income taxes	425.0	(33.6)	391.4
Deficit	(2,532.8)	(98.7)	(2,631.5)

5. SEGMENTED INFORMATION

Year ended December 31, 2013	Green Power	Liquids Transportation and Storage	Alliance Canada	Corporate	Consolidated
(millions of Canadian dollars)					
Transportation and other services	**-**	**214.7**	**-**	**-**	**214.7**
Electricity sales	**188.5**	**-**	**-**	**-**	**188.5**
Operating and maintenance	**(32.9)**	**(80.5)**	**-**	**-**	**(113.4)**
Management and administrative	**-**	**-**	**-**	**(21.8)**	**(21.8)**
Depreciation and amortization	**(62.6)**	**(67.1)**	**-**	**-**	**(129.7)**
	93.0	**67.1**	**-**	**(21.8)**	**138.3**
Income from equity investments	**1.5**	**-**	**54.4**	**-**	**55.9**
Other income/(expense)	**(0.3)**	**0.1**	**(0.3)**	**0.1**	**(0.4)**
Interest expense	**-**	**-**	**-**	**(73.6)**	**(73.6)**
Income tax expense	**-**	**-**	**-**	**(28.4)**	**(28.4)**
Earnings before extraordinary item	**94.2**	**67.2**	**54.1**	**(123.7)**	**91.8**
Extraordinary item, net of tax	**-**	**(16.5)**	**-**	**4.5**	**(12.0)**
Earnings	**94.2**	**50.7**	**54.1**	**(119.2)**	**79.8**
Total assets	**1,429.2**	**1,095.8**	**202.0**	**29.8**	**2,756.8**
Additions to property, plant and equipment	**5.2**	**70.8**	**-**	**-**	**76.0**
Goodwill	**-**	**28.8**	**-**	**-**	**28.8**

Year ended December 31, 2012[1]	Green Power	Liquids Transportation and Storage	Alliance Canada	Corporate	Consolidated
(millions of Canadian dollars)					
Transportation and other services	-	199.3	-	-	199.3
Electricity sales	190.3	-	-	-	190.3
Operating and maintenance	(32.1)	(67.9)	-	-	(100.0)
Management and administrative	-	-	-	(19.3)	(19.3)
Depreciation and amortization	(63.2)	(58.9)	-	-	(122.1)
	95.0	72.5	-	(19.3)	148.2
Income from equity investments	1.0	-	52.8	-	53.8
Other income	0.1	0.2	0.4	-	0.7
Interest expense	-	(6.4)	-	(56.0)	(62.4)
Income tax expense	(6.3)	(3.2)	-	(41.1)	(50.6)
Earnings	89.8	63.1	53.2	(116.4)	89.7
Total assets	1,468.5	1,081.3	226.2	224.4	3,000.4
Additions to property, plant and equipment	9.8	141.0	-	-	150.8
Goodwill	-	28.8	-	-	28.8

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

Year ended December 31, 2011[1]	Green Power	Liquids Transportation and Storage	Alliance Canada	Corporate	Consolidated
(millions of Canadian dollars)					
Transportation and other services	-	191.2	-	-	191.2
Electricity sales	151.7	-	-	-	151.7
Operating and maintenance	(25.5)	(57.7)	-	-	(83.2)
Management and administrative	-	-	-	(16.7)	(16.7)
Depreciation and amortization	(52.2)	(61.2)	-	-	(113.4)
	74.0	72.3	-	(16.7)	129.6
Income from equity investments	1.7	-	51.0	-	52.7
Other income	1.5	52.7	0.4	-	54.6
Interest expense	(0.3)	(10.2)	-	(32.0)	(42.5)
Income tax expense	(16.8)	(16.7)	-	(16.2)	(49.7)
Earnings	60.1	98.1	51.4	(64.9)	144.7
Total assets	1,528.5	990.0	286.5	35.8	2,840.8
Additions to property, plant and equipment	207.8	131.1	-	-	338.9
Goodwill	-	28.8	-	-	28.8

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.

Significant Customer

The Ontario Power Authority represents 95% (2012 – 95%; 2011 – 93%) of electricity sales revenue recorded in the Green Power segment in the year ended December 31, 2013.

6. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

GENERAL INFORMATION ON RATE REGULATION AND ITS ECONOMIC EFFECTS
Saskatchewan System
The Saskatchewan Gathering System and the Westspur System are regulated by SME and the NEB, respectively. The Saskatchewan Gathering System follows a cost of service methodology. Tolls are subject to change from time to time based on differences between the estimated cost of service and actual costs incurred and include a 6.5% return on rate base. On April 1, 2013, the Fund announced it concluded a settlement (the Settlement) with a group of shippers relating to new tolls on the Westspur System. The Settlement resulted in the discontinuance of rate regulated accounting for the Westspur System and the Fund recorded a write-off related to a deferred regulatory asset which will not be collected under the terms of the Settlement *(Note 24)*.

Alliance Canada
Shippers on the Alliance System entered into 15-year transportation contracts, expiring in December 2015, which set out the cost of service toll methodology used to calculate annual tolls. Alliance Canada is regulated by the NEB, with whom Alliance files toll adjustments annually. The tolls include a return on equity component of 11.26% after tax and are based on a deemed 70% debt and 30% equity structure. The financial statement effect of regulation to which Alliance Canada is subject is inherent within the Fund's equity accounting for its investment in Alliance Canada.

FINANCIAL STATEMENT EFFECTS
Accounting for rate-regulated entities has resulted in recognition of the following regulatory assets and liabilities:

December 31,	**2013**	2012
(millions of Canadian dollars)		
Regulatory assets/(liabilities)		
Saskatchewan Gathering System		
Transportation revenue adjustment[1]	**32.9**	19.1
Deferred income taxes[2]	**(6.7)**	(5.5)
Westspur System		
Transportation revenue adjustment[1]	**-**	14.7
Deferred income taxes[2]	**-**	(0.1)
Alliance Canada		
Deferred income taxes[2]	**34.7**	44.7

1 The transportation revenue adjustment is the cumulative difference between actual expenses incurred and estimated expenses included in transportation tolls. Transportation revenue adjustments are not included in rate base. To the extent that the regulator's actions differ from the Fund's expectations, the amount of the transportation revenue adjustment ultimately recovered could differ significantly from the amounts recorded. The recovery period is approximately five years and dependent on shipper throughput levels.

2 The regulatory asset/(liability) is the corresponding balance to a deferred income tax asset/(liability) that arises within entities subject to rate regulation. The balance has been recognized as a regulatory asset/(liability) since the flow-through treatment of taxes for rate-setting purposes would ensure eventual recovery of these balances as the temporary differences reverse. The recovery period will depend on the period over which the deferred income tax amounts reverse.

7. ACQUISITIONS

Crude Oil Storage and Renewable Energy Entities
On December 10, 2012, the Fund acquired 100% interests in the Crude Oil Storage and Renewable Energy Entities from Enbridge and wholly-owned subsidiaries of Enbridge (the 2012 Acquisition). Cash consideration was $1.16 billion, inclusive of adjustments for working capital and other post close adjustments of $1.3 million.

The components of the net cash consideration for this acquisition were as follows:

(millions of Canadian dollars)	
Acquisition price	1,164.0
Working capital and post close adjustments	(1.3)
Less: cash acquired	(3.9)
	1,158.8

The 2012 Acquisition of the Crude Oil Storage and Renewable Energy Entities was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the Crude Oil Storage and Renewable Energy Entities were recorded at Enbridge's historic carrying values, with any difference from consideration paid charged to unitholders' deficit.

The purchase price was recorded as follows:

(millions of Canadian dollars)	
Cash	3.9
Accounts receivable	13.0
Property, plant and equipment	937.7
Intangible assets	10.9
Goodwill	28.8
Accounts payable	(4.0)
Asset retirement obligation	(0.8)
Deferred income taxes	(108.0)
	881.5
Excess purchase price over net assets acquired	281.2
Cash consideration	1,162.7

Earnings for the year ended December 31, 2012 include the results of the Crude Oil Storage and Renewable Energy Entities as though the 2012 Acquisition occurred at the beginning of the year. The incremental effect of retrospectively adjusting the Fund's consolidated financial statements to include the results of operations of Crude Oil Storage and Renewable Energy Entities for the periods prior to the 2012 Acquisition is as follows:

Year ended December 31,	2012	2011
(millions of Canadian dollars)		
Earnings		
Revenues	108.2	75.4
Operating and administrative	(24.4)	(15.4)
Depreciation and amortization	(35.4)	(26.8)
Interest income/(expense), net	(6.1)	42.1
Income tax expense	(10.4)	(19.1)
Earnings	31.9	56.2

Year ended December 31,	2012	2011
(millions of Canadian dollars)		
Cash provided from operating activities	69.4	104.9
Cash (used in)/provided from investing activities	(9.8)	783.0
Cash used in financing activities	(67.1)	(897.0)
	(7.5)	(9.1)

December 31,	2012	2011
(millions of Canadian dollars)		
Current assets	-	24.9
Property, plant and equipment, net	-	969.4
Other long-term assets	-	40.3
	-	1,034.6
Current liabilities	-	(33.4)
Long-term debt	-	(140.0)
Other long-term liabilities	-	(63.2)
Noncontrolling interest	-	(26.0)
	-	(262.6)
Net assets	-	772.0

Noncontrolling interest represents a 10% interest of Greenwich Windfarm Limited Partnership held by a third party. Prior to closing of the 2012 Acquisition, a wholly-owned subsidiary of Enbridge acquired the remaining 10% interest in Greenwich for $26.5 million, increasing its ownership interest to 100%.

Renewable Entities

On October 21, 2011, the Fund acquired 100% interests in the Renewable Entities from a wholly-owned subsidiary of Enbridge (the 2011 Acquisition). Cash consideration was $1.24 billion, inclusive of working capital adjustments of $11.2 million.

The components of the net cash consideration for the 2011 Acquisition were as follows:

(millions of Canadian dollars)	
Acquisition price	1,230.0
Working capital adjustments	11.2
Less: cash acquired	(10.1)
	1,231.1

The 2011 Acquisition was accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the assets and liabilities of the Renewable Entities were recorded at Enbridge’s historic carrying values, with any difference from consideration paid charged to unitholders’ deficit.

The purchase price was recorded as follows:

(millions of Canadian dollars)	
Cash	10.1
Accounts receivable	15.3
Property, plant and equipment	1,073.4
Intangible assets	18.0
Accounts payable	(2.5)
Asset retirement obligation	(2.3)
Long-term liabilities	(0.6)
Deferred income taxes	(158.0)
	953.4
Excess purchase price over net assets acquired	287.8
Cash consideration	1,241.2

Earnings for the year ended December 31, 2011 include the results of the Renewable Entities as though the 2011 Acquisition occurred at the beginning of the year. The incremental effect of retrospectively adjusting the Fund's consolidated financial statements to include the results of operations of the Renewable Entities for the period prior to the 2011 Acquisition is as follows:

Year ended December 31,	2011
(millions of Canadian dollars)	
Earnings	
Revenues	107.9
Operating and administrative	(18.1)
Depreciation and amortization	(38.0)
Interest income/(expense), net	1.3
Income tax expense	(15.1)
Earnings	38.0

Year ended December 31,	2011
(millions of Canadian dollars)	
Cash provided from operating activities	92.1
Cash (used in)/provided from investing activities	8.3
Cash (used in)/provided from financing activities	(100.1)
	0.3

8. ACCOUNTS RECEIVABLE AND OTHER

December 31,	**2013**	2012[1]
(millions of Canadian dollars)		
Unbilled revenues	**18.2**	11.1
Trade receivables	**23.9**	24.2
Inventory	**7.7**	2.4
Prepaid expenses and deposits	**3.2**	3.9
Income taxes receivable	**-**	4.9
Due from affiliates *(Note 22)*	**3.1**	0.3
Short-term portion of derivative assets *(Note 18)*	**0.2**	-
	56.3	46.8

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

Accounts receivable include $16.8 million (2012 – $12.0 million) due from Ontario Power Authority at December 31, 2013.

9. PROPERTY, PLANT AND EQUIPMENT

December 31,	Weighted Average Depreciation Rate	**2013**	2012[1]
(millions of Canadian dollars)			
Green Power			
Wind turbines, solar panels and other	4.3%	**1,548.1**	1,545.9
Liquids Transportation and Storage			
Pipeline in service	8.4%	**613.4**	431.2
Pumping equipment, tanks and other	3.3%	**694.9**	693.3
Under construction		**12.1**	149.5
		2,868.5	2,819.9
Accumulated depreciation		**(551.4)**	(430.4)
Property, plant and equipment, net		**2,317.1**	2,389.5

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

Depreciation expense for the year ended December 31, 2013 was $126.2 million (2012 – $118.5 million; 2011 – $110.8 million).

10. LONG-TERM INVESTMENTS

December 31,	Ownership Interest	**2013**	2012
(millions of Canadian dollars)			
Equity investments			
Alliance Canada	50%	**163.5**	177.8
Green Power			
NRGreen Power Limited Partnership	50%	**50.8**	29.1
SunBridge Wind Power Project	50%	**5.2**	5.7
Total		**219.5**	212.6

Summarized combined financial information of the Fund's interests in joint ventures accounted for under the equity method is as follows:

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Earnings			
Revenues	**237.2**	243.3	230.3
Operating and administrative	**(80.3)**	(82.7)	(69.3)
Depreciation and amortization	**(61.2)**	(64.6)	(62.4)
Other income/(expense)	**0.6**	1.0	(0.1)
Interest expense	**(40.4)**	(43.2)	(45.8)
Earnings	**55.9**	53.8	52.7

December 31,	**2013**	2012
(millions of Canadian dollars)		
Current assets	**78.8**	55.7
Property, plant and equipment, net	**751.4**	795.0
Deferred amounts and other assets	**12.0**	10.6
Current liabilities	**(77.5)**	(61.0)
Long-term debt	**(537.5)**	(580.8)
Other long-term liabilities	**(7.7)**	(6.9)
Net assets	**219.5**	212.6

Certain assets of Alliance Canada are pledged as collateral to Alliance Canada's lenders and to the lenders of Alliance Pipeline US, an affiliated entity.

11. DEFERRED AMOUNTS AND OTHER ASSETS

December 31,	**2013**	2012
(millions of Canadian dollars)		
Regulatory assets *(Note 6)*	**60.9**	72.9
Deferred financing costs	**6.6**	8.2
Long-term portion of derivative assets *(Note 18)*	**2.5**	1.6
Other	**0.2**	0.4
	70.2	83.1

12. INTANGIBLE ASSETS

December 31, 2013	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Power purchase agreements	**4.4%**	**30.6**	**(5.0)**	**25.6**
Software	**18.6%**	**4.9**	**(3.0)**	**1.9**
		35.5	**(8.0)**	**27.5**

December 31, 2012[1]	Weighted Average Amortization Rate	Cost	Accumulated Amortization	Net
(millions of Canadian dollars)				
Power purchase agreements	4.4%	30.6	(3.6)	27.0
Software	18.8%	4.1	(2.2)	1.9
		34.7	(5.8)	28.9

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

Total amortization expense for intangible assets was $2.2 million (2012 – $2.2 million; 2011 – $1.4 million) for the year ended December 31, 2013. The Fund expects aggregate amortization expense for the years ending December 31, 2014 through 2018 of $2.3 million, $2.3 million, $2.3 million, $2.3 million and $2.3 million, respectively.

13. ACCOUNTS PAYABLE AND OTHER

December 31,	**2013**	2012[1]
(millions of Canadian dollars)		
Operating accrued liabilities	**14.6**	11.4
Trade payables	**6.9**	4.0
Construction payable	**13.2**	33.4
Income taxes payable	**0.8**	0.2
Short-term portion of derivative liabilities *(Note 18)*	**0.8**	2.1
Interest payable	**15.1**	10.1
Other	**3.4**	2.2
	54.8	63.4

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

14. DEBT

December 31,	**2013**	2012
(millions of Canadian dollars)		
Medium term notes		
5.25% due December 22, 2014	**90.0**	90.0
5.00% due June 22, 2017	**100.0**	100.0
4.00% due December 20, 2018	**125.0**	125.0
4.85% due November 12, 2020	**100.0**	100.0
2.92% due December 14, 2017	**225.0**	225.0
4.10% due February 22, 2019	**300.0**	300.0
4.85% due February 22, 2022	**200.0**	200.0
3.94% due January 13, 2023	**275.0**	275.0
Floating rate due November 28, 2014	**200.0**	200.0
Credit facilities	**40.0**	250.0
Debt discount	**(0.8)**	(0.8)
Total debt	**1,654.2**	1,864.2
Current maturities	**(290.0)**	-
Long-term debt	**1,364.2**	1,864.2

Medium Term Notes

The Medium Term Notes (MTNs) are unsecured and redeemable by the Fund prior to maturity, in whole or in part, from time to time, at the option of the Fund at a price equal to the greater of the applicable Government of Canada yield price and par. Interest on the MTNs maturing in 2014, 2017 and 2018 is payable semi-annually in June and December. Interest on the MTNs maturing in 2020 and the floating rate note maturing in 2014 is payable semi-annually in May and November. Interest on the MTNs maturing in 2019 and in 2022 is payable semi-annually in February and August. Interest on the MTN maturing in 2023 is payable semi-annually in January and July.

For the year ending December 31, 2014, MTN maturities are $290.0 million. MTN maturities for the years ending December 31, 2017 and thereafter are $1,324.2 million.

At December 31, 2013, the MTNs had a fair value of $1,654.8 million (2012 – $1,677.9 million) based on quoted market prices.

Credit Facility

At December 31, 2013, the Fund had a $500 million (2012 – $500 million) 3-year standby credit facility with a syndicate of commercial banks. In June 2013, the Fund amended its credit facility, extending the maturity date to June 28, 2016. On an annual basis, the Fund may request a one year extension of the applicable maturity date. The working capital portion of the facility is $30.0 million (2012 – $30.0 million). At December 31, 2013, $12.0 million (2012 – $9.7 million) of letters of credit were outstanding under the Fund's credit facility. The weighted average interest rate on indebtedness incurred on the Fund's credit facility for the year ended December 31, 2013 was 2.6% (2012 – 2.6%). The Fund's credit facility carries a standby fee of 0.24% (2012 – 0.25%) per annum.

The Fund is subject to several covenants under its credit facility. Certain covenants were modified in the amended facility including the addition of a covenant that limits outstanding debt to a percentage of the Fund's consolidated capitalization and the elimination of a covenant which limited outstanding debt to a multiple of EBITDA (earnings before interest, taxes, depreciation and amortization). The Fund is in compliance with all covenants as at December 31, 2013.

INTEREST EXPENSE

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Interest expense on long-term debt	**70.4**	51.1	23.5
Interest on affiliate loans *(Note 22)*	**0.6**	11.3	18.2
Amortization of deferred financing fees and bank charges	**4.0**	2.6	1.9
Capitalized interest	**(1.4)**	(2.6)	(1.1)
	73.6	62.4	42.5

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.

Interest obligations on the Fund's MTNs for the years ending December 31, 2014 through 2018 are $59.1 million, $54.3 million, $54.3 million, $51.7 million and $42.7 million, respectively.

15. OTHER LONG-TERM LIABILITIES

December 31,	**2013**	2012[1]
(millions of Canadian dollars)		
Asset retirement obligations	**19.8**	18.5
Derivative liabilities *(Note 18)*	**0.8**	1.4
Other	**2.4**	3.0
	23.0	22.9

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

A reconciliation of movements in the Fund's asset retirement obligation is as follows:

December 31,	**2013**	2012[1]
(millions of Canadian dollars)		
Obligations, beginning of year	**18.5**	17.1
Accretion expense	**1.4**	1.4
Abandonment costs incurred	**(0.1)**	-
Obligations, end of year	**19.8**	18.5

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

A legal obligation exists for the retirement of certain assets within the Liquids Transportation and Storage and Green Power operating segments. The undiscounted amount of expected cash flows required to settle the asset retirement obligations related to certain assets in the Liquids Transportation and Storage and Green Power segments is estimated at $225.0 million (2012 – $225.0 million) and estimated to be settled between 2016 and 2060. The liability for the expected cash flows as recognized in the financial statements reflected a weighted average discount rate of 8.1% (2012 – 8.1%).

16. ECT PREFERRED UNITS

(millions of Canadian dollars, number of units in millions)	**2013** Number of Units	**2013** Mezzanine Equity	2012 Number of Units	2012 Mezzanine Equity	2011 Number of Units	2011 Mezzanine Equity
ECT preferred units, series 1						
Balance, beginning of year	**38.0**	**894.8**	38.0	764.3	38.0	688.2
Redemption value adjustment	**-**	**(10.0)**	-	130.5	-	76.1
Balance, end of year	**38.0**	**884.8**	38.0	894.8	38.0	764.3
ECT preferred units, series 2						
Balance, beginning of year	**16.1**	**377.7**	16.1	322.6	-	-
Issued	**-**	**-**	-	-	16.1	301.0
Redemption value adjustment	**-**	**(4.2)**	-	55.1	-	21.6
Balance, end of year	**16.1**	**373.5**	16.1	377.7	16.1	322.6
ECT preferred units, series 3						
Balance, beginning of year	**13.2**	**349.8**	-	-	-	-
Issued	**-**	**-**	13.2	304.6	-	-
Redemption value adjustment	**-**	**(43.6)**	-	45.2	-	-
Balance, end of year	**13.2**	**306.2**	13.2	349.8	-	-
ECT preferred units, series 4						
Issued	**5.2**	**130.8**	-	-	-	-
Redemption value adjustment	**-**	**(9.1)**	-	-	-	-
Balance, end of year	**5.2**	**121.7**	-	-	-	-
Total ECT preferred units	**72.5**	**1,686.2**	67.3	1,622.3	54.1	1,086.9

On February 26, 2013, the Fund issued 5,232,000 ECT preferred units, series 4, priced at $25.00 per unit. Gross proceeds of $130.8 million were used to repay indebtedness.

On December 10, 2012 the Fund issued 13,159,000 ECT preferred units, series 3, priced at $23.15 per unit. Gross proceeds of $304.6 million were used to partially fund the 2012 Acquisition.

On October 21, 2011, the Fund issued 16,051,000 ECT preferred units, series 2, priced at $18.75 per unit. Gross proceeds of $301.0 million, were used to partially fund the 2011 Acquisition.

ECT preferred units are entitled to non-cumulative distributions when declared by ECT, have no direct voting rights except in limited circumstances and all mature on June 30, 2033.

The ECT preferred units have an Exchange Right which provides Enbridge, the holder of the ECT preferred units, with the right to exchange all or part of the ECT preferred units for trust units on a one-for-one basis at any time prior to maturity. Should the holder exercise the Exchange Right as a holder of trust units, it would be entitled to the trust unitholder rights described in Note 17. Accordingly ECT preferred units are accounted for as redeemable instruments and their redemption price is calculated based on the redemption price of trust units.

Cash distributions of $116.1 million (2012 – $80.8 million; 2011 – $58.8 million) were declared on the ECT preferred units during the year ended December 31, 2013.

17. TRUST UNITS

December 31,	2013 Number of Units	2013 Amount	2012 Number of Units	2012 Amount	2011 Number of Units	2011 Amount
(millions of Canadian dollars, number of units in millions)						
Common trust units, beginning of year	**61.2**	**1,477.3**	49.2	989.7	34.6	626.7
Issued	**4.8**	**119.2**	12.0	277.4	14.6	274.0
Share issue costs	**-**	**(4.1)**	-	(9.2)	-	(9.2)
Redemption value adjustment	**-**	**(56.8)**	-	219.4	-	98.2
Common trust units, end of year[1]	**66.0**	**1,535.6**	61.2	1,477.3	49.2	989.7

1 Enbridge owned 9.5 million common trust units at December 31, 2013 (2012 – 9.5 million; 2011 – 9.5 million).

On February 26, 2013, the Fund issued 4,768,000 trust units priced at $25.00 per unit. Gross proceeds of $119.2 million were used to repay indebtedness.

On December 10, 2012, the Fund issued 11,982,000 trust units priced at $23.15 per unit. Gross proceeds of $277.4 million were used to partially fund the 2012 Acquisition.

On October 21, 2011, the Fund issued 14,616,000 trust units priced at $18.75 per unit. Gross proceeds of $274.0 million were used to partially fund the 2011 Acquisition.

Pursuant to the Trust Indenture, an unlimited number of trust units may be issued. Each unit represents an equal undivided beneficial interest in any distributions from the Fund and in the net assets in the event of termination or wind-up of the Fund. All units are voting and have equal rights and privileges. At any given time, the Fund is required to reserve a sufficient number of trust units to satisfy the Exchange Right.

Trust units are redeemable at any time at the option of the holder. At December 31, 2013 and 2012, the redemption price per trust unit is equal to the net asset value per trust unit, calculated with reference to the market price of an ENF common share, adjusted for non-consolidated assets and liabilities of ENF. The maximum amount payable by the Fund in respect of redemptions in any calendar month is limited to $0.1 million. To the extent that a unitholder is not entitled to receive cash upon the redemption of trust units, the redemption price shall be satisfied, subject to all necessary regulatory approvals, by way of a distribution of Fund property, which may include ECT notes or other assets held by the Fund.

During the year ended December 31, 2013, the Fund declared $105.8 million (2012 – $73.6 million; 2011 – $53.5 million) in cash distributions to trust unitholders.

18. DERIVATIVE FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

MARKET PRICE RISK

The Fund’s earnings, cash flows and OCI are subject to movements in interest rates, foreign exchange rates and commodity prices (collectively, market price risk). Formal risk management policies, processes and systems have been designed to mitigate these risks.

The following summarizes the types of market price risks to which the Fund is exposed and the risk management instruments used to mitigate them.

Interest Rate Risk

The Fund’s earnings, cash flows and OCI are exposed to short term interest rate variability due to the regular repricing of its variable rate debt, primarily credit facilities. Floating to fixed interest rate swaps are used to hedge against the effect of future interest rate movements. The Fund has implemented a program to significantly mitigate the volatility of short-term interest rates on interest expense through 2017 at an average swap rate of 1.85%.

The Fund’s earnings, cash flows and OCI are also exposed to variability in longer term interest rates ahead of anticipated fixed rate debt issuances. Forward starting interest rate swaps may be used to hedge against the effect of future interest rate movements. At December 31, 2013, $180 million of future fixed rate term debt issuances had been hedged at a swap rate of 4.29% (2012 – nil).

The Fund uses qualifying derivative instruments to manage interest rate risk.

Foreign Exchange Risk

The Fund’s earnings, cash flows and OCI are subject to foreign exchange rate variability due to certain United States dollar denominated revenues and expenses. The Fund uses qualifying derivative instruments to manage foreign exchange rate risk.

Commodity Price Risk

The Fund’s earnings, cash flows and OCI are exposed to changes in commodity prices due to collection of allowance oil on certain crude oil pipelines, generation of power sold pursuant to floating rate supply agreements and through commitments to purchase and sell natural gas in connection with capacity held on the Alliance System. The Fund may use crude oil, power and natural gas derivative instruments to fix a portion of the variable price exposures that may arise from these activities. The Fund uses a combination of qualifying and non-qualifying derivative instruments to manage commodity price risk.

TOTAL DERIVATIVE INSTRUMENTS

The following table summarizes the balance sheet location, carrying value and fair value of the Fund's derivatives instruments. The Fund did not have any outstanding fair value or net investment hedges as at December 31, 2013 and 2012.

December 31, 2013	Derivative Instruments used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Accounts receivable and other					
Commodity contracts	**0.2**	**-**	**0.2**	**-**	**0.2**
	0.2	**-**	**0.2**	**-**	**0.2**
Deferred amounts and other assets					
Interest rate contracts	**1.9**	**-**	**1.9**	**(0.2)**	**1.7**
Foreign exchange contracts	**0.2**	**-**	**0.2**	**-**	**0.2**
Commodity contracts	**0.3**	**0.1**	**0.4**	**-**	**0.4**
	2.4	**0.1**	**2.5**	**(0.2)**	**2.3**
Accounts payable and other					
Interest rate contracts	**(0.7)**	**-**	**(0.7)**	**-**	**(0.7)**
Commodity contracts	**-**	**(0.1)**	**(0.1)**	**-**	**(0.1)**
	(0.7)	**(0.1)**	**(0.8)**	**-**	**(0.8)**
Other long-term liabilities					
Interest rate contracts	**(0.2)**	**-**	**(0.2)**	**0.2**	**-**
Commodity contracts	**(0.3)**	**(0.3)**	**(0.6)**	**-**	**(0.6)**
	(0.5)	**(0.3)**	**(0.8)**	**0.2**	**(0.6)**
Total net derivative asset/(liability)					
Interest rate contracts	**1.0**	**-**	**1.0**	**-**	**1.0**
Foreign exchange contracts	**0.2**	**-**	**0.2**	**-**	**0.2**
Commodity contracts	**0.2**	**(0.3)**	**(0.1)**	**-**	**(0.1)**
	1.4	**(0.3)**	**1.1**	**-**	**1.1**

December 31, 2012	Derivative Instruments used as Cash Flow Hedges	Non-Qualifying Derivative Instruments	Total Derivative Instruments	Amounts Available for Offset	Total Net Derivative Instruments
(millions of Canadian dollars)					
Deferred amounts and other assets					
Interest rate contracts	0.6	-	0.6	(0.4)	0.2
Commodity contracts	0.8	0.2	1.0	-	1.0
	1.4	0.2	1.6	(0.4)	1.2
Accounts payable and other					
Interest rate contracts	(1.7)	-	(1.7)	-	(1.7)
Foreign exchange contracts	(0.1)	-	(0.1)	-	(0.1)
Commodity contracts	(0.2)	(0.1)	(0.3)	-	(0.3)
	(2.0)	(0.1)	(2.1)	-	(2.1)
Other long-term liabilities					
Interest rate contracts	(0.5)	-	(0.5)	0.4	(0.1)
Foreign exchange contracts	(0.5)	-	(0.5)	-	(0.5)
Commodity contracts	-	(0.4)	(0.4)	-	(0.4)
	(1.0)	(0.4)	(1.4)	0.4	(1.0)
Total net derivative asset/(liability)					
Interest rate contracts	(1.6)	-	(1.6)	-	(1.6)
Foreign exchange contracts	(0.6)	-	(0.6)	-	(0.6)
Commodity contracts	0.6	(0.3)	0.3	-	0.3
	(1.6)	(0.3)	(1.9)	-	(1.9)

The following table summarizes the maturity and notional principal or quantity outstanding related to the Fund’s derivative instruments.

December 31, 2013	2014	2015	2016	2017	2018	Thereafter
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	**202.0**	**200.0**	**190.0**	**90.0**	**7.0**	**-**
Interest rate contracts - long-term borrowings *(millions of Canadian dollars)*	**-**	**-**	**-**	**180.0**	**-**	**-**
U.S. dollar forwards *(millions of United States dollars)*	**2.0**	**2.1**	**2.1**	**2.2**	**2.2**	**4.2**
Commodity contracts - power *(megawatts per hour)*	**4.8**	**4.8**	**4.8**	**4.8**	**2.8**	**2.8**

December 31, 2012	2013	2014	2015	2016	2017	Thereafter
Interest rate contracts - short-term borrowings *(millions of Canadian dollars)*	209.0	202.0	200.0	182.0	-	-
U.S. dollar forwards *(millions of United States dollars)*	2.0	2.1	2.1	2.1	2.2	6.2
Commodity contracts – power *(megawatts per hour)*	4.8	4.8	4.8	4.8	4.8	3.0

Effect of Derivative Instruments on the Statements of Earnings and Comprehensive Income
The following table presents the effect of cash flow hedges on the Fund's consolidated earnings and comprehensive income.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Amount of unrealized gain/(loss) recognized in OCI			
Interest rate contracts	**0.4**	(2.2)	(7.8)
Foreign exchange contracts	**0.8**	(0.1)	0.1
Commodity contracts	**(0.8)**	8.8	(9.4)
Total unrealized gain/(loss) recognized in OCI	**0.4**	6.5	(17.1)
Amount of gain/(loss) reclassified from AOCI to earnings *(effective portion)*			
Interest rate contracts[1]	**5.1**	3.5	2.0
Foreign exchange contracts[2]	**-**	0.1	0.2
Commodity contracts[3]	**0.5**	(0.5)	0.2
Total gain/(loss) reclassified from AOCI to earnings *(effective portion)*	**5.6**	3.1	2.4

1 Gain/(loss) reported within Interest expense in the Consolidated Statements of Earnings.
2 Gain/(loss) reported within Other income/(expense) in the Consolidated Statements of Earnings.
3 Gain/(loss) reported within Revenue and Other income/(expense) in the Consolidated Statements of Earnings.

The estimated net amount of existing losses reported in accumulated other comprehensive income that is expected to be reclassified to net income within the next 12 months is $0.7 million. Actual amounts reclassified to earnings depend on the interest rates, foreign exchange rates and commodity prices in effect when derivative contracts that are currently outstanding are settled.

Non-Qualifying Derivatives
The following table presents the unrealized gains and losses associated with changes in the fair value of the Fund's non-qualifying derivatives.

Year ended December 31,	**2013**	2012	2011
(millions of Canadian dollars)			
Commodity contracts[1]	**0.1**	(0.1)	-
Total unrealized derivative fair value gain/(loss)	**0.1**	(0.1)	-

1 Gain/(loss) reported within Revenue in the Consolidated Statements of Earnings.

LIQUIDITY RISK
Liquidity risk is the risk that the Fund will not be able to meet its financial obligations, including commitments *(Note 23)*, as they become due. In order to manage this risk, the Fund forecasts the cash requirements over the near and long term to determine whether sufficient funds will be available when required. The Fund's primary sources of liquidity and capital resources are funds generated from operations, draws under committed credit facilities and the issuance of medium term notes. The Fund maintains a current shelf prospectus with Canadian securities regulators, which enables, subject to market conditions, ready access to Canadian public capital markets. Cash flow from operations, in combination with available committed credit facilities and, if required, capital markets funding, is expected to be sufficient to meet the forecast liquidity and capital resource requirements of the Fund.

CREDIT RISK
Entering into derivative financial instruments may result in exposure to credit risk. Credit risk arises from the possibility that a counterparty will default on its contractual obligations. The Fund enters into risk management transactions only with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by utilization of credit exposure limits, contractual requirements and frequent assessment of counterparty credit worthiness.

At December 31, 2013 and 2012, the Fund had group credit concentrations and maximum credit exposure in the following counterparty segments:

December 31,	**2013**	2012
(millions of Canadian dollars)		
Canadian financial institutions	**1.7**	0.5
Enbridge affiliate	**0.2**	0.8
	1.9	1.3

Credit risk also arises from trade and other receivables and is mitigated through credit exposure limits and by requiring less creditworthy shippers to provide credit enhancement which may include letters of credit, posting of collateral, netting provisions or other contractual requirements. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

The Fund's financial assets and liabilities measured at fair value on a recurring basis include derivative instruments. The fair value of derivative instruments reflects the Fund's best estimates of market value based on generally accepted valuation techniques or models and supported by observable market prices and rates. When such values are not available, the Fund uses discounted cash flow analysis from applicable yield curves based on observable market inputs to estimate fair value.

At December 31, 2013, the Fund's long-term debt had a fair value of $1,694.8 million (2012 – $1,927.9 million). This fair value measurement has been classified as a level 2 fair value measurement.

The Fund categorizes those financial assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement.

Level 1

Level 1 includes financial instruments measured at fair value based on unadjusted quoted prices for identical assets and liabilities in active markets that are accessible at the measurement date. An active market for a financial instrument is considered to be a market where transactions occur with sufficient frequency and volume to provide pricing information on an ongoing basis. The Fund did not have any financial instruments categorized as Level 1 as at December 31, 2013 or 2012.

Level 2

Level 2 includes financial instrument valuations determined using directly or indirectly observable inputs other than quoted prices included within Level 1. Financial instruments in this category are valued using models or other industry standard valuation techniques derived from observable market data. Such valuation techniques include inputs such as quoted forward prices, time value, volatility factors and broker quotes that can be observed or corroborated in the market for the entire duration of the financial instrument. Financial instruments valued using Level 2 inputs include non-exchange traded derivatives such as over-the-counter interest rate swaps for which observable inputs can be obtained.

Level 3

Level 3 includes financial instrument valuations based on inputs which are less observable, unavailable or where the observable data does not support a significant portion of the financial instruments' fair value. Generally, Level 3 financial instruments are longer dated transactions, occur in less active markets, occur at locations where pricing information is not available or have no binding broker quote to support Level 2 classification. The Fund has developed methodologies, benchmarked against industry standards, to determine fair value for these financial instruments based on extrapolation of observable future prices and rates. Financial instruments valued using Level 3 inputs include long-dated commodity derivative contracts.

The Fund uses the most observable inputs available to estimate the fair value of its financial instruments. When possible, the Fund estimates the fair value of its financial instruments based on quoted market prices. If quoted market prices are not available, the Fund uses estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, the Fund uses standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps. Depending on the type of financial instrument and nature of the underlying risk, the Fund uses observable market prices (interest, foreign exchange and commodity) and volatility as primary inputs to these valuation techniques. Finally, the Fund considers its own credit default swap spread as well as the credit default swap spreads associated with its counterparties in its estimation of fair value.

The Fund has categorized its derivative instruments, measured at fair value as follows:

December 31, 2013	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Current derivative assets	**-**	**-**	**0.2**	**0.2**
Long-term derivative assets	**-**	**2.1**	**0.4**	**2.5**
Financial liabilities				
Current derivative liabilities	**-**	**(0.7)**	**(0.1)**	**(0.8)**
Long-term derivative liabilities	**-**	**(0.1)**	**(0.7)**	**(0.8)**
Total net asset/(liability)	**-**	**1.3**	**(0.2)**	**1.1**

December 31, 2012	Level 1	Level 2	Level 3	Total
(millions of Canadian dollars)				
Financial assets				
Long-term derivative assets	-	0.6	1.0	1.6
Financial liabilities				
Current derivative liabilities	-	(1.8)	(0.3)	(2.1)
Long-term derivative liabilities	-	(1.0)	(0.4)	(1.4)
Total net asset/(liability)	-	(2.2)	0.3	(1.9)

The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments were as follows:

	Fair value at December 31, 2013 *(millions of Canadian dollars)*	**Unobservable Input**	**Minimum Price**	**Maximum Price**	**Weighted Average Price**	
Commodity Contracts – Financial[1]						
Power	(0.2)	Forward Power Price	43.50	61.39	53.60	$/MWH

1 Financial forward commodity contracts are valued using a market approach valuation technique.

If adjusted, the significant unobservable inputs disclosed in the table above would have a direct impact on the fair value of the Fund’s Level 3 derivative instruments. The significant unobservable inputs used in the fair value measurement of Level 3 derivative instruments consist of forward commodity prices. Changes in forward commodity prices would result in significantly different fair values for long positions, with offsetting impacts to short positions.

Changes in net fair value of financial instruments classified as Level 3 in the fair value hierarchy were as follows:

Year ended December 31,	**2013**	2012
(millions of Canadian dollars)		
Level 3 net financial asset/(liability) at beginning of year	**0.3**	(7.8)
Total gains, unrealized		
Included in OCI	**-**	8.1
Settlements	**(0.5)**	-
Level 3 net financial asset/(liability) at end of year	**(0.2)**	0.3

The Fund's policy is to recognize transfers as of the last day of the reporting period. There were no transfers between levels as at December 31, 2013 and 2012.

19. OTHER INCOME/(EXPENSE)

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Interest income from affiliate loans *(Note 22)*	**0.4**	0.4	54.2
Other	**(0.8)**	0.3	0.4
	(0.4)	0.7	54.6

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.

20. CHANGES IN OPERATING ASSETS AND LIABILITIES

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Accounts receivable and other, net	**(10.0)**	9.7	3.0
Accounts payable and other	**12.8**	-	1.7
Due to affiliates	**2.8**	(2.7)	11.9
Deferred amounts and other assets	**(18.7)**	(22.3)	(12.0)
Other long-term liabilities	**(0.7)**	(8.1)	3.0
	(13.8)	(23.4)	7.6

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7.

21. INCOME TAXES

INCOME TAX RATE RECONCILIATION

Year ended December 31,	**2013**	2012[1]	2011[1]
(millions of Canadian dollars)			
Earnings before income taxes and extraordinary loss	**120.2**	140.3	194.4
Federal statutory corporate income tax rate	**15.0%**	15.0%	16.5%
Income taxes at federal statutory rate	**18.0**	21.0	32.1
Increase/(decrease) resulting from:			
Provincial taxes	**11.9**	21.0	19.2
Taxable component of trust distributions	**(6.2)**	4.7	(6.1)
Deferred income taxes related to regulated operations	**5.3**	4.3	6.2
Temporary differences not recognized in non-taxable entities	**(0.7)**	(0.6)	(0.5)
Other	**0.1**	0.2	(1.2)
Income tax expense	**28.4**	50.6	49.7
Effective income tax rate	**23.6%**	36.1%	25.6%

1 Retrospectively adjusted to furnish comparative information related to the 2011 and 2012 Acquisitions. See Notes 2 and 7

Comparative figures within the income tax reconciliation for 2012 and 2011 have been revised to conform to the presentation followed for the current year. In 2013, a preferable presentation format was adopted which calculates expected taxes using a federal statutory rate as opposed to a combined federal and provincial rate. This format is preferable as it is more commonly used by companies following U.S. GAAP.

COMPONENTS OF DEFERRED INCOME TAXES

Deferred income tax assets and liabilities are recognized for the future tax consequences of differences between carrying amounts of assets and liabilities and their respective tax bases. Major components of deferred income tax assets and liabilities were:

December 31,	**2013**	2012[1]
(millions of Canadian dollars)		
Deferred income tax liabilities		
Property, plant and equipment and intangible assets	**53.1**	42.3
Investments	**347.2**	347.6
Deferred revenue	**8.9**	9.1
Other	**0.2**	0.4
Total deferred income tax liabilities	**409.4**	399.4
Deferred income tax assets		
Loss carryforwards	**17.3**	19.7
Asset retirement obligations	**4.4**	4.1
Other	**1.8**	1.4
Total deferred income tax assets	**23.5**	25.2
Net deferred income tax liabilities	**385.9**	374.2
Presented as follows:		
Current deferred income tax assets	**(4.0)**	(16.7)
Non-current deferred income tax assets	**(0.7)**	(0.7)
Current deferred income tax liabilities	**0.3**	0.2
Non-current deferred income tax liabilities	**390.3**	391.4
Net deferred income tax liabilities	**385.9**	374.2

1 Retrospectively adjusted to furnish comparative information related to the 2012 Acquisition. See Notes 2 and 7.

The Fund and its subsidiaries are subject to taxation in Canada. The Fund is open to examination by certain tax authorities for the 2009 to 2012 tax years. The material jurisdictions in which the Fund is subject to potential examinations are only within Canada (Federal, Alberta and Ontario).

The Fund has no unrecognized tax benefits related to uncertain tax positions as at December 31, 2013 and no accrued interest or penalties thereon.

Current income taxes for the year ended December 31, 2013 was an expense of $1.1 million (2012 – $4.4 million recovery; 2011 – $2.7 million expense). During the year ended December 31, 2013, the Fund recognized the benefit of unused loss carryforwards of $65.6 million (2012 – $74.1 million; 2011 – $109.8 million) which start to expire in 2027 and beyond.

22. RELATED PARTY TRANSACTIONS

Unless otherwise noted, all related party transactions have been measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The acquisitions of the Renewable Entities and the Crude Oil Storage and Renewable Energy Entities were accounted for as transactions among entities under common control. See Note 7 for additional disclosure regarding the acquisitions.

Affiliate Loans
In 2013, ENF advanced $17.5 million (2012 – $6.8 million) to a subsidiary corporation of the Fund pursuant to a subordinated demand loan. At December 31, 2013, $24.3 million (2012 – $6.8 million) was outstanding. Interest on the demand loan was charged at 4.25% per annum. Interest expense on the loan was $0.6 million (2012 – $0.1 million) for the year ended December 31, 2013 and $0.1 million (2012 – $16,278) was included in accounts payable and other as at December 31, 2013.

In December 2012, the Fund received a $582.0 million loan from Enbridge, a related party by virtue of its ECT preferred units and trust unit investment in the Fund, to partially finance the acquisition of Enbridge's interests in the Crude Oil Storage and Renewable Energy Entities. The loan had a 10-year maturity and accrued interest at the rate of 5.0% per annum with interest payable semi-annually in May and November of each year. The loan was repayable at any time in whole or in part, and was unsecured and subordinate to all external debt issued by the Fund. In December 2012, the Fund repaid the loan in full. Interest expense on this loan of $0.5 million was incurred by the Fund for the year ended December 31, 2012, and had been paid in full as at December 31, 2012.

In October 2011, the Fund received a $655.0 million loan from Enbridge to partially finance the acquisition of Enbridge's interests in the Renewable Entities. The loan had a 10-year maturity and accrued interest at the rate of 6.0% per annum with interest payable semi-annually in May and November of each year. The loan was repayable at any time in whole or in part, and was unsecured and subordinate to all external debt issued by the Fund. In December 2011, the Fund repaid $155.0 million of this loan to Enbridge and repaid the remaining balance of $500.0 million in full in February 2012. Interest expense on this loan of $4.4 million (2011 – $7.5 million) was incurred by the Fund for the year ended December 31, 2012, and had been paid in full as at December 31, 2012.

A long-term note receivable from equity investee consists of a promissory note outstanding from Alliance Pipeline Ltd. The balance outstanding at December 31, 2013 and 2012 was $3.7 million. The note is interest bearing and matures in full on December 6, 2015. Interest income earned on this note during each of the years ended December 31, 2013, 2012 and 2011 was $0.4 million.

The Crude Oil Storage and Renewable Energy Entities had borrowed $140.0 million from Enbridge at December 31, 2009. During the year ended December 31, 2012, the loans were repaid in full. Interest accrued on the demand loans at rates varying from 6.8% to 8.1% per annum. Interest expense on these loans of $6.4 million (2011 – $10.7 million) was incurred by the Crude Oil and Renewable Energy Entities for the year ended December 31, 2012.

The Crude Oil Storage and Renewable Energy Entities had loaned affiliates of Enbridge $1.6 billion at December 31, 2009. The affiliates repaid $560.0 million during the year ended December 31, 2010 and repaid the remaining balance of $1.0 billion during the year ended December 31, 2011. The loans were due on demand and accrued interest at rates varying from 6.5% to 7.1%. Interest income earned on these loans was $53.8 million for the year ended December 31, 2011.

Green Power

Certain renewable power projects do not have employees and use the services of Enbridge for managing and operating the business. These services totaled $4.2 million for 2013 (2012 – $4.6 million; 2011 – $4.2 million) and included a $1.5 million management fee charged by Enbridge for managing the Ontario Wind Project, Talbot Wind Project and Sarnia Solar Project pursuant to a management agreement. At December 31, 2013, $0.3 million (2012 – $1.6 million) was included in due to affiliates.

The Fund has a contract to sell to Enbridge all available emission reduction credits generated by the Fund's interest in the Chin Chute and Magrath projects. The contract has an initial 20-year term ending October 1, 2026 and provides for a fixed price of $5 per tonne of avoided CO_2 emissions, based on a negotiated rate of converting megawatts generated to tonnes of emissions reduced, plus applicable taxes. The Fund earned $0.2 million (2012 – $0.2 million; 2011 – $0.3 million) for the sale of these emission reduction credits in the year ended December 31, 2013.

One of the Fund's wind power projects, Magrath, has a long-term power price swap, expiring in 2024, with Enbridge Pipelines Inc., a wholly-owned subsidiary of Enbridge. The terms of the agreement are to substantially fix the prices of wind power production. Revenues of $15,695 (2012 – $0.6 million; 2011 – $0.1 million) related to this agreement are reported within the Fund's revenue for the year ended December 31, 2013.

Liquids Transportation and Storage

The Fund does not have any employees and uses the services of Enbridge for managing and operating the businesses comprising the Liquids Transportation and Storage segment. These services, which are charged at cost in accordance with service agreements, were $40.6 million for 2013 (2012 – $35.4 million; 2011 – $29.4 million) of which $5.2 million (2012 – $4.3 million) was included in due to affiliates at December 31, 2013.

The Fund provides certain operational services to Enbridge Pipelines (Bakken) LP, a wholly-owned subsidiary of Enbridge Energy Partners, an affiliate of the Fund, and charged $1.2 million (2012 – nil) for the year ended December 31, 2013.

The Fund has contracts with shippers who are also affiliates of the Fund through common ownership interests of Enbridge. Revenue from affiliates for the year ended December 31, 2013 was $2.3 million (2012 – $3.5 million; 2011 – $7.3 million) of which $0.1 million was included in accounts receivable and other at December 31, 2013 (2012 – $0.3 million).

Alliance Canada

A subsidiary of Enbridge provides management services to Sable NGL Services L.P. (SNGL Services), a joint venture entity in which the Fund holds a 50% interest. SNGL Services paid management fees of $0.2 million under this agreement during the year ended December 31, 2013 (2012 – $0.1 million; 2011 – $0.3 million). SNGL recorded revenues of $3.6 million (2012 – $3.4 million; 2011 – $3.5 million) and expenses of $5.2 million (2012 – $6.2 million; 2011 – $6.7 million) for natural gas sales and purchases with an affiliate of Enbridge, of which the Fund's interest is 50%.

Alliance Canada has contracts with shippers who are also affiliates of the Fund through common ownership interests of Enbridge. The Fund's share of Alliance Canada's revenue from affiliates for the year ended December 31, 2013 was $23.2 million (2012 – $23.0 million; 2011 – $21.4 million). The terms of these contracts are the same as those agreed to with independent third parties.

Administrative and operation services are provided by Alliance Canada to Alliance Pipeline US, an entity related to the Fund through common ownership interests. The Fund's share of amounts charged to Alliance Pipeline US during the year ended December 31, 2013 was $21.2 million (2012 – $20.5 million; 2011 – $18.4 million).

Administrative and facility support services are provided by Alliance Canada to Aux Sable Canada LP and Aux Sable Liquid Products LP (the Aux Sable Entities), which are entities related to the Fund through common ownership. The Fund's share of amounts charged to the Aux Sable Entities during the year ended December 31, 2013 was $0.2 million (2012 – $0.1 million; 2011 – $0.3 million).

Corporate
In 2013, the Fund paid $4.1 million (2012 **–** $9.2 million; 2011 **–** $9.2 million) for share issue costs incurred in connection with the offering of 3,820,000 common shares (2012 **–** 9,597,000 subscription receipts; 2011 – 11,707,000 subscription receipts) by ENF. Proceeds from the offerings were used by ENF to purchase additional trust units of the Fund.

Under the management and administrative agreements with EMSI, an incentive fee is payable annually to EMSI based on cash distributions above a base distribution level. During the year ended December 31, 2013, incentive fees were $19.6 million (2012 – $12.4 million; 2011 – $10.4 million), of which, $19.6 million (2012 – $12.4 million) was included in due to affiliates at December 31, 2013. In addition, a base fee of $0.1 million (2012 – $0.1 million; 2011 – $0.1 million) is payable annually for providing administrative and management services and was included in due to affiliates at December 31, 2013.

ECT preferred unit distributions payable to Enbridge of $9.8 million at December 31, 2013 were recorded as distributions payable (2012 – $9.0 million). Trust unit distributions payable to ENF of $7.6 million (2012 – $6.9 million) and to Enbridge of $1.3 million (2012 – $1.3 million) at December 31, 2013 were recorded as distributions payable.

ECT has an agreement with ENF under which it reimbursed ENF $1.0 million (2012 – $1.4 million; 2011 – $0.6 million) for certain general and administrative costs during the year ended December 31, 2013 of which $0.1 million (2012 – $0.4 million) was included in due to affiliates at December 31, 2013.

23. COMMITMENTS AND CONTINGENCIES

At December 31, 2013, the Fund had commitments as detailed below:

	Total	Less than 1 year	2 years	3 years	4 years	5 years	Thereafter
(millions of Canadian dollars)							
Operating leases	2.0	1.0	0.7	0.3	-	-	-
Maintenance agreements	57.6	12.5	14.3	11.8	10.1	4.5	4.4
Land lease commitments	36.6	1.9	2.4	2.4	2.4	2.5	25.0
Purchase commitments	3.0	3.0	-	-	-	-	-
Total	99.2	18.4	17.4	14.5	12.5	7.0	29.4

24. EXTRAORDINARY LOSS

On April 1, 2013, the Fund announced it concluded the Settlement with a group of shippers relating to new tolls on the Westspur System. The NEB ordered the new tolls final on February 6, 2014. Pursuant to the Settlement, the tolls on the Westspur System are fixed and increased annually with reference to a pre-identified inflation index, subject to throughput remaining within a volume band close to volumes recently transported on the Westspur System. The Settlement resulted in the discontinuance of rate regulated accounting for the Westspur System and the Fund recorded an after-tax write-off of $12.0 million in the first quarter of 2013 related to a deferred regulatory asset which will not be collected under the terms of the Settlement.

Prior to reaching the Settlement, revenue on the Westspur System was recognized in a manner consistent with the underlying agreements consistent with rate regulated accounting guidance. The Fund discontinued the application of rate regulated accounting to the operations of the Westspur System on a prospective basis on April 1, 2013. Pursuant to the Settlement, the Westspur System will retain exposure to potential variability in certain future costs and throughput volumes, subject to various protection mechanisms. As such, the Westspur System no longer meets all of the criteria required for the continued application of rate-regulated accounting treatment.