Management's Discussion and Analysis

AltaLink, L.P.

March 1, 2013

Table of Contents

Management's Discussion and Analysis	1
Executive Summary	1
Our Business and Strategies	1
Our Capability to Deliver Results	2
How We Measure Our Performance	3
Our Partnership Structure	5
Regulated Tariff Revenue	6
Our Transmission Facilities	9
Overview of Electricity Industry in Alberta	9
Transmission Planning and Development	12
Major Capital Projects	13
Environment, Health and Safety	16
Non-GAAP Financial Measures	18
Financial Position	19
Liquidity and Capital Resources	20
Results of Operations	23
Risk Management	26
Transactions with Related Parties	31
Legal Proceedings	32
Off Balance Sheet Arrangements	32
Critical Accounting Estimates	32
Contingencies	32
Accounting Changes	32
Forward Looking Information	34

Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reflects events known to us as of March 1, 2013. This MD&A is intended to provide you with an understanding of our business, our strategy, our performance, our expectations for the future, and how we manage risk and financial resources. Our Board of Directors approved this MD&A on March 1, 2013, based on the recommendation of our Audit Committee, which reviewed this MD&A in accordance with its terms of reference.

You should read this MD&A in conjunction with our legal advisory on Forward Looking Information, which we have included at the end of this MD&A, as well as our audited financial statements for the years ended December 31, 2012 and 2011 (the Financial Statements) and the notes thereto.

The financial information in this MD&A is presented in Canadian dollars, which is our functional currency.

Unless otherwise noted, references in this MD&A to "we", "us", "our", "AltaLink" or "the Partnership" mean AltaLink, L.P. and references to a "quarter" and "year" refer to the three-month and twelve-month periods ended December 31, 2012, respectively. References to "AESO" mean Alberta Electric System Operator; "AUC" mean Alberta Utilities Commission; "CEA" mean Canadian Electrical Association; "CWIP" mean Construction Work-In-Progress; "GTA" mean General Tariff Application"; "GCOC" mean Generic Cost of Capital.

Additional information relating to our business including our Annual Information Form is available on SEDAR at www.sedar.com.

Executive Summary

2012 Highlights

- We invested $974.7 million (2011 - $618.7 million) in capital projects to reinforce and expand the transmission system;
- We earned comprehensive income of $107.0 million (2011 - $85.3 million) ;
- We issued $575.0 million of long-term senior debt at historically low interest rates to finance our capital construction program;
- The AUC approved several major facility applications, including approval to construct the $1.5 billion Western Alberta Transmission Line;
- We completed a competitive procurement process to acquire Engineering, Procurement and Construction Management (EPCM) services to support project delivery for the next 5 years;
- We received safety awards from the CEA in recognition of our top quartile safety record; and
- We filed our GTA for 2013-2014 with the AUC.

Our Business and Strategies

We own and operate regulated electricity transmission facilities in the Province of Alberta. Through our transmission facilities, we deliver electricity safely, reliably and efficiently to approximately 85% of Alberta's population to meet continuously changing customer needs under all operating conditions. We connect generation plants to major load centres, cities and large industrial plants throughout our 212,000 square kilometre service area, which covers a diverse geographic area, including most major urban centres in central and southern Alberta. Our transmission facilities comprise approximately half of the total kilometres in the Alberta Interconnected Electric System, including interconnections with British Columbia's transmission system that link Alberta with the North American western interconnected system.

Our vision is to be the leading owner and operator of regulated electricity transmission in Alberta. To achieve this vision, we are focused on:

Safe, Reliable and Cost-Effective Operations
We strive for excellence in our operating, maintenance and capital investment practices. We are committed to operating our transmission facilities efficiently and reliably and to protecting the safety of our employees, the public and the environment. We use life-extension and long-term asset replacement programs to replace facilities when they reach the end of their useful lives.

Prudently Expanding our Transmission Network
We are focused on keeping the lights on for Albertans and are committed to reinforcing Alberta's transmission infrastructure to ensure that the province's electricity grid can enable future prosperity. Although we grow and expand our transmission network primarily by constructing new transmission facilities, we are always searching for innovative methods to get more out of the existing grid, such as extending the life of the existing assets, re-using existing facilities and implementing new technologies to minimize the impact on land use and landowners. We will investigate and assess any future opportunities to acquire existing regulated electricity transmission assets in Alberta.

Stakeholder Engagement
We focus our engagement practices on providing our stakeholders with timely, easy to understand information about transmission projects. Our process is designed to gather stakeholder input to help us identify routes on our new projects with the lowest overall impact on land use and landowners.

Our Capability to Deliver Results

We leverage our core competencies and resources to deliver results for our stakeholders.

Financial Strength

We align our financing strategy with the regulated capital structure approved by the AUC and with targets for our key financial metrics. We finance our operations and maintenance capital expenditures from operating cash flows. We intend to fund the growth in capital expenditures from the balance of our operating cash flows, additional borrowings under our capital markets platform, and equity contributions from our limited partner, AltaLink Investments, L.P.. Through their indirect ownership in AltaLink Investments, L.P., SNC-Lavalin Group Inc. provides solid financial sponsorship and the capacity to contribute the additional equity needed to finance the capital investments we expect to make in the future.

Operations

We design and implement operational, maintenance and capital investment practices to fulfill our commitment to the safe, reliable and cost effective operation of our transmission business. To do so, we employ experienced people with the necessary expertise and knowledge. Our maintenance programs are designed to sustain the useful function of existing transmission assets to ensure that those assets operate in an efficient and reliable manner. Our program-based maintenance activities cover the broad functional spectrum of the transmission business, including tools, safety, lines, substations, telecommunications, meters, vehicles, buildings, control centre and information technology. We utilize life extension and long-range asset replacement programs to ensure timely and effective replacement of assets which have reached the end of their useful life.

Capital Project Execution

We execute our capital projects program through the use of an Engineering, Procurement and Construction Management (EPCM) model. This strategic outsourcing arrangement enhances our capability to deliver results to consumers by facilitating design and construction of our capital projects in a timely and cost-effective manner.

In our 2011 - 2012 GTA, we summarized our plans for a competitive procurement process for EPCM services after our 10-year contract with SNC-Lavalin ATP Inc. expired in April 2012. The projects underway and past the Proposal to Provide Service submission stage at the expiry date are expected to be completed by SNC-Lavalin ATP Inc. under the previous contract. On April 30, 2012, we awarded five-year contracts to SNC-Lavalin ATP Inc. and Burns & McDonnell Canada Ltd. to provide EPCM services for future capital projects.

Organizational Leadership and People

Effective January 21, 2013, Scott Thon, our Chief Executive Officer has accepted a secondment to SNC-Lavalin for up to six months. Our Board of Directors has appointed our Chief Operating Officer, Dennis Frehlich, as interim President and Chief Executive Officer. While Scott is working with SNC-Lavalin, he will not be involved in the management of AltaLink, and he has accepted an appointment as a member of our Board of Directors during this period.

Our leadership team's experience and expertise, combined with our employees' knowledge and dedication to "keeping the lights on" through operational excellence are key to our ability to deliver. We have established a proven track record of reliability, safety and cost effectiveness that compares favourably with our peers and we align our short-term and long-term incentive pay with the needs of our customers.

We strive continuously to enhance programs to attract, retain and develop a high quality workforce to enable us to not only sustain our business, but to remain at the forefront of innovation and continuous improvement. We employ over 750 skilled and dedicated people and are continuing to increase our workforce to deliver on the major transmission projects planned in Alberta.

Environmental Leadership

We provide environmental leadership through innovative practices and sound risk management. In designing and constructing new transmission facilities, we consider ways to reduce land use impacts and improve efficiency. We strive to be leaders in environmental best practices, such as our Avian Protection Plan that was the first of its kind in Canada.

How We Measure Our Performance

Delivering Customer Value

We use certain key measures to determine whether we are meeting our goals and the needs of our customers. Our performance compares favourably to other transmission facility owners in Canada for reliability, safety and cost effectiveness.

Reliability

We operate our transmission system so as to minimize disruption of service to our customers. Nevertheless, severe weather and other unplanned events cause service disruptions to which we respond as quickly as possible. During the twelve months ended December 31, 2012, we reduced the duration of service disruptions, as noted in the table below. We also decreased the frequency of service disruptions compared to the preceding twelve-month period.

A strong, efficient transmission system ensures Albertans have access to multiple generation resources from across the province, instead of a limited number of local generation sources. A strong transmission system also ensures that all generators compete, driving down the price of energy and producing the electricity required to keep Alberta's economy growing.

	Year ended December 31		
	2012	2011	2010
Duration of outages (SAIDI)[1]			
AltaLink	**0.61**	0.73	1.25
CEA[3]	**N/A**	1.11	1.53
Frequency of outages (SAIFI)[2]			
AltaLink	**0.78**	1.04	1.52
CEA[3]	**N/A**	1.53	1.67

1. System Availability Interruption Duration Index is the average number of interruption hours per delivery point during a twelve-month period.
2. System Availability Interruption Frequency Index is the average number of interruptions per delivery point during a twelve-month period.
3. Statistics from the CEA are provided on a transmission only basis. The CEA results are not yet available for 2012.

Safety

We received two safety awards from the CEA, recognizing our continued top quartile safety performance – a President's Award of Excellence in Employee Safety for utilities, and a Vice President's Award of Safety Excellence for a transmission and distribution business. The CEA also recognized one of our employees with a Lifesaving Award.

Our safety management initiatives encompass all aspects of our safety systems, and our safety statistics are consistently stronger than our peers. Our safety statistics include all man-hours worked by contractors and sub-contractors. During the twelve months ended December 31, 2012 our workplace Injury Frequency Rate remained at 50% of our peers in Canada. We strive to continuously improve our safety performance through focused training and our ongoing commitment to continuously improving our safety culture and safety management processes.

	Year ended December 31		
	2012	2011	2010
All injury frequency rate (AIFR)			
AltaLink[1]	**1.03**	0.61	0.31
CEA[2]	**N/A**	2.02	2.09

1. Number of lost time accidents and medical aid incidents per 200,000 man hours worked by employees and contractors.
2. Statistics from the Canadian Electrical Association are provided on a transmission-only basis, and are for employees only. The CEA results are not yet available for 2012.

Cost Effectiveness

Our goal is to provide Albertans with cost effective transmission service. Electricity is at the core of our economy and critical to our society. Therefore, we focus on ensuring reliability of supply to our customers, while delivering services cost effectively. Our continuous improvement culture embraces our project execution programs, maintenance process, centralized work planning, and scheduling. We will continue to seek business improvements across our organization while delivering reliable and safe transmission service to our customers.

Financial and Operational Performance

Transmission Tariffs

We recognize revenue based on transmission tariffs approved by the AUC, including adjustments arising from deferral accounts established under those tariffs. In 2011, the AUC issued the GTA and GCOC decisions, which approved our transmission tariff revenue for 2011 and 2012, subject to certain adjustments. We made these adjustments in our compliance filing, dated September 17, 2012. On January 30, 2013, the AUC issued Decision 2013-023 approving our compliance filing, without further adjustments.

We filed our GTA for 2013-2014 on July 30, 2012, and the AUC has scheduled an oral hearing for May 2013. We expect the AUC to issue a decision in the fourth quarter of 2013. In our GTA for 2013-2014 we requested a revenue requirement of $501.0 million and $656.1 million for 2013 and 2014 respectively, driven by our forecast increase in capital expenditures. In Decision 2013-024, dated January 31, 2013, the AUC approved our 2013 interim tariff of $38.0 million per month, effective January 1, 2013.

Growth in Regulated Capital Assets

Growth in our regulated capital assets (both rate base and construction work-in-progress (CWIP)) provides reliability of supply of transmission service to our customers and is one of the key indicators of future revenue streams. As a regulated utility, we earn most of our net income from allowed returns on equity invested in our regulated capital assets. Our regulated capital assets are the foundation for providing fair returns to our equity investors. We calculate our allowed returns on equity by multiplying our mid-year investments in rate base and CWIP by the equity ratio and rate of return approved by the AUC. Our operating cash flow relates primarily to (i) the return on equity on our rate base and, as approved in the GTA Decision, most of our CWIP; (ii) recovery of deemed income taxes; and (iii) recovery of depreciation on our rate base assets.

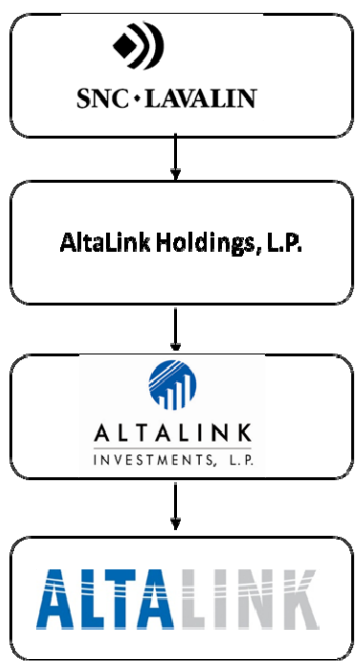
The table below summarizes our mid-year rate base and construction work in progress:

Mid-year rate base and construction work in progress	**2012**	2011	2010
(in millions of dollars)			
Mid-year rate base	**$ 1,781.6**	$ 1,552.2	$ 1,266.9
Mid-year construction work in progress	**794.0**	397.3	306.5

For the year ended December 31, 2012, our capital program included more than $118.0 million of capital replacement and upgrade projects and more than $887.0 million of expansion projects directly assigned to us by the AESO. In our 2013 – 2014 GTA, we have forecast our 2013 and 2014 direct assigned capital expenditures to be $1.5 billion and $1.7 billion respectively. Our actual capital program may vary from our regulatory filings, depending on the timing of regulatory approvals, directions from the Alberta Electric System Operator (AESO), and other factors beyond our control. In particular, certain recent developments that we discuss in the Major Capital Projects section of this MD&A may materially impact our capital expenditure outlook. As at the end of December 2012, the AUC has approved facility applications totalling approximately $3.4 billion, of which $1.0 billion has been spent to date. We have also filed facility applications for $1.2 billion, which are now at various stages in the regulatory process.

Our Partnership Structure

We are a limited partnership, formed under the laws of Alberta on July 3, 2001 pursuant to the Limited Partnership Agreement between AltaLink Management Ltd., as general partner, and AltaLink Investments, L.P., as the sole limited partner. The general partner manages the regulated electricity transmission facilities that we own and operate in the Province of Alberta. Both AltaLink Investments, L.P. and its sole limited partner, AltaLink Holdings, L.P. are managed by AltaLink Investment Management Ltd.



Regulated Tariff Revenue

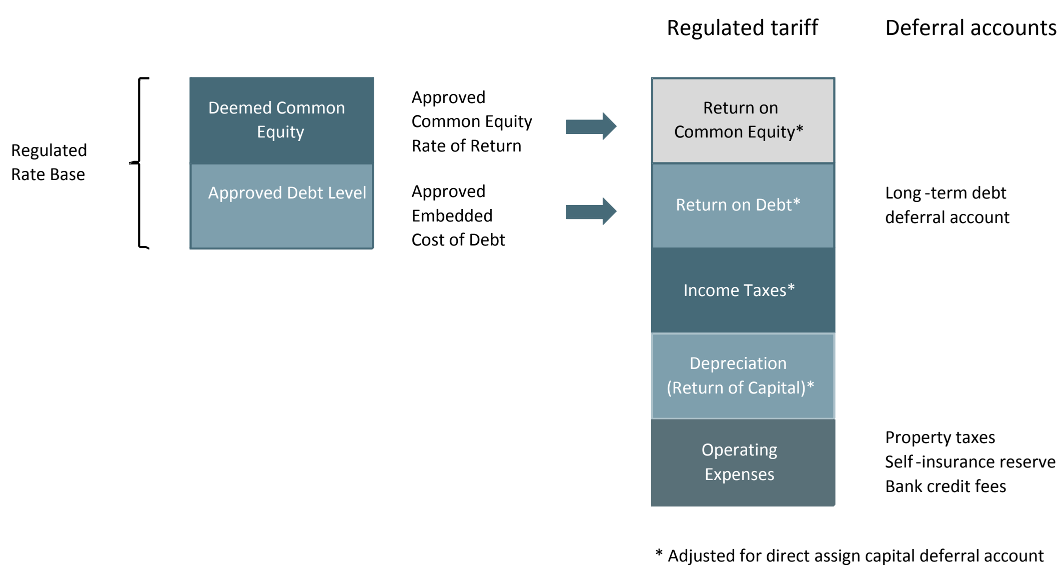
We are an electric utility regulated by the AUC, pursuant to the Electric Utilities Act (Alberta), the Public Utilities Act (Alberta), the Alberta Utilities Commission Act (Alberta) and the Hydro and Electric Energy Act (Alberta). Through various regulatory decisions, these statutes and their respective regulations impact our tariffs, rates, construction, operations and financing.

We receive all of our regulated transmission tariffs, including settlements of deferral and reserve accounts, from the AESO. We and other transmission facility owners are permitted to charge a tariff for the use of our transmission facilities. Such tariffs are regulated by the AUC under the provisions of the Electric Utilities Act in respect of rates and terms and conditions of service. Under the Transmission Regulation, the AUC must consider that it is in the public interest to provide consumers the benefit of unconstrained transmission access to competitive generation and the wholesale electricity market. In regulating transmission tariffs, the AUC must facilitate sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and foster a stable investment climate and a continued stream of capital investment for the transmission system.

Overview of Our Transmission Tariffs

Under the Electric Utilities Act, we must prepare and file applications with the AUC for approval of tariffs to be paid by the AESO for the use of our transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves such tariff applications based on a cost-of-service regulatory model under a forward test year basis. Under this model, the AUC provides us with a reasonable opportunity to (i) earn a fair return on equity; and (ii) recover our forecast costs, including operating expenses, depreciation, borrowing costs and taxes (including deemed income taxes) associated with our regulated transmission business. The AUC must approve tariffs that are just, reasonable, and not unduly preferential, arbitrary or unjustly discriminatory. Our transmission tariffs are not dependent on the price or volume of electricity transmitted through our transmission system. We receive our annual transmission tariffs from the AESO in equal monthly instalments, based on the revenue requirement approved by the AUC for the applicable year. We and the AESO settle amounts owing or due in respect of deferral and reserve accounts after the AUC issues its decision on these matters. Tariff adjustments arising from deferral and reserve accounts relate to services we have provided in past periods and their settlement is not contingent on providing future services.

The following diagram outlines the principal components of our transmission tariff revenue:



Return on Rate Base and Allowance for Funds Used During Construction

We are entitled to earn a fair return on the equity capital we invest in our business. Under its generic approach to regulating the cost of capital, the AUC sets the ratios of debt and common equity it permits each utility to use in calculating the cost of capital related to its rate base and construction work in progress. The deemed capital structures approved by the AUC reflect how each utility is deemed to be financing its regulatory rate base and assets under construction. In determining the deemed capital structure for each utility, the AUC may take into account: (i) an assessment of the business risk of each utility sector and applicant; (ii) deemed capital structures previously approved for each applicant; (iii) comparable determinations by regulators in other jurisdictions; (iv) interest coverage ratio analysis; (v) bond rating analysis; and (vi) any other relevant factors.

We calculate our return on common equity by multiplying the approved common equity ratio by a generic rate of return on common equity approved by the AUC. We calculate our return on debt using rates and procedures approved by the AUC in our general tariff applications. Our actual capital structure and cost of debt may vary from those used by the AUC to calculate our regulated cost of capital.

Generic Cost of Capital

On December 8, 2011, the AUC issued Decision 2011-474 regarding cost of capital matters applicable to all electricity and natural gas utilities under its jurisdiction, including us. In its decision, the AUC set a deemed capital structure, expressed as proportions of debt and equity, for each utility and prescribed a generic rate of return on common equity to be applied against the common equity component of the deemed capital structures of all utilities. Utilities are required to use the deemed capital structures and generic rate of return on common equity when calculating their tariff revenue requirements. Please refer to the Regulatory Financial Risk section in this MD&A for more information with respect to the implications of reduced equity and return on our financial results.

In Decision 2011-474, which was effective January 1, 2011, the AUC decreased the generic rate of return on common equity applicable to all utilities to 8.75% from the previously approved rate of 9.00%. In addition, the AUC increased our common equity ratio from 36% to 37%. The approved common equity ratio and generic rate of return on common equity will remain in effect until changed by the AUC. In 2012, we and other utilities regulated by the AUC applied to the Alberta Court of Appeal for Leave to Appeal, based on, among other things, the AUC's finding that utilities bear the risk of stranded assets. We subsequently applied to the AUC for Review and Variance (R&V) of Decision 2011-474 on the basis that the AUC erred in fact, law or jurisdiction by:

- finding that prudently incurred costs should be removed from revenue requirement and rates;
- determining that risks and costs in relation to stranded assets should be borne by the investors of the utility;
- having made the finding that the utilities bear the risk of stranded assets, the AUC failed to reflect adequate return on that risk in its determinations of capital structure and adequate return on that risk; and
- failing to provide adequate notice and a fair process.

On June 4, 2012, the AUC issued Decision 2012-154, rejecting the R&V application by the Alberta regulated utilities on the basis that its statements regarding stranded asset risk were unnecessary and that issues relating to stranded asset risk should be evaluated in the context of the relevant legislation and case law. The AUC decided to address the matters raised in the R&V in a broader Utility Asset Disposition Proceeding, which would consider and evaluate the issue of utility asset dispositions and stranded assets. The parties to the appeal agreed to adjourn the leave application to October 17, 2013, and the AUC has suspended the 2013 GCOC proceeding pending completion of the Utility Asset Disposition Proceeding.

Deemed capital structure and generic returns approved by the AUC	2012	2011	2010
Deemed capital structure			
Approved common equity ratio	**37.00%**	37.00%	36.00%
Approved debt ratio	**63.00%**	63.00%	64.00%
Generic returns			
Approved return on equity	**8.75%**	8.75%	9.00%

Transmission Tariffs

The table below summarizes the 2012 tariff approved by the AUC in Decision 2013-023, which was issued on January 30, 2013. The table also includes the revenue requirement that we have requested for 2013 and 2014:

	2014	2013	2012
	Forecast	Forecast	Actual
(in millions of dollars)			
Return on equity	$ 167.7	$ 119.4	$ 83.7
Return on debt	144.9	102.8	83.0
Operating costs	132.5	117.4	104.4
Miscellaneous revenue	(7.0)	(7.0)	(7.6)
Depreciation and amortization	160.1	126.6	104.3
Income taxes	57.9	41.7	20.3
Revenue requirement	$ 656.1	$ 501.0	$ 388.1

**Totals may not add due to rounding*

In Decision 2013-024, dated January 31, 2013, the AUC approved an interim refundable revenue requirement of $455.8 million for 2013.

The forecast revenue requirement is based on continuation of the credit metric relief approved for 2011 and 2012, as well as further relief by allowing us to use the future income tax method for calculating deemed provincial income taxes and a temporary 2% increase in our common equity ratio from 37% to 39%. There is no assurance that the AUC will approve any or all of the requested credit metric relief measures. Please refer to the Regulatory Financial risk section in this MD&A for more information.

Operating expenses

We are entitled to recover prudent forecasted operating expenses, net of any miscellaneous revenue, related to our regulated transmission business.

Taxes Other Than Income Taxes

We are entitled to recover real property taxes and other taxes (other than income taxes) attributable to our regulated transmission business.

Depreciation and Reserve for Salvage Costs

Based on independent third party studies, we forecast the estimated useful lives of our transmission facilities. We are entitled to recover the net book value of assets included in our regulated rate base, together with the forecast salvage costs, on a straight-line basis over their useful lives using the equal life group method.

Income Taxes

As a limited partnership, we do not pay federal or provincial income taxes directly. Income taxes related to our operations are paid by the corporations owned by SNC-Lavalin that hold partnership interests in AHLP. Our transmission tariffs include recovery of income taxes that the AUC deems we would have paid in connection with our regulated operations if we were a tax paying entity. The AUC approves our collection of these amounts as the corporate partners of AHLP are obliged to pay these amounts to the tax authorities.

In Decision 2011-453, the AUC has directed us to continue to use the future income tax method for calculating deemed federal income taxes and the flow-through method for provincial income taxes for 2011 and 2012 revenue requirements. In our 2013-2014 GTA, we requested approval to continue to use the future income tax method for federal income taxes and to begin to use the future income tax method for provincial income taxes for 2013 and 2014 revenue requirements. In the future, the AUC may direct us to stop using the future income tax method for federal income taxes and provide options for the disposition of the future income tax balance.

Our Transmission Facilities

The Alberta Integrated Electric System (AIES) is a network or grid of transmission facilities operating at high voltages ranging from 69kV to 500kV. The grid delivers electricity from generating units across the province through more than 21,000 kilometres of transmission lines and over 400 substations. The AIES is interconnected to British Columbia`s transmission system through a 500kV circuit that we own and operate and to Saskatchewan's transmission system via a 150 MW direct current converter station.

Our transmission facilities are an integral part of the AIES. We own, approximately 12,000 kilometres of transmission lines and 280 substations which we manage and operate through our control centre and extensive telecommunications network. Our transmission lines are comprised of wood or metal support structures, conductors, foundations, insulators, connecting hardware and grounding systems. Our substations are comprised of high-voltage power transformers, power circuit breakers, switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems, buildings and security systems. Our substations integrate the transmission lines into a network and transform the voltage of electricity to meet the requirements of generators and customers. We generally accept electricity into our system at our generator interconnection substations and deliver power to distribution facility owners and wholesale customers at our customer supply substations. Where the transmission system connects to a distribution network, transmission substations step down the voltage to distribution level voltages.

Our real-time control centre and telecommunication system enable us to continuously monitor, control and manage our transmission facilities and coordinate with the AESO and other transmission facility owners. Our telecommunication system includes microwave radio, fibre optic cable, power line carrier and mobile radio systems. To further support the maintenance and operation of our transmission facilities, we own and operate office and service buildings, transport and work equipment, and information technology assets.

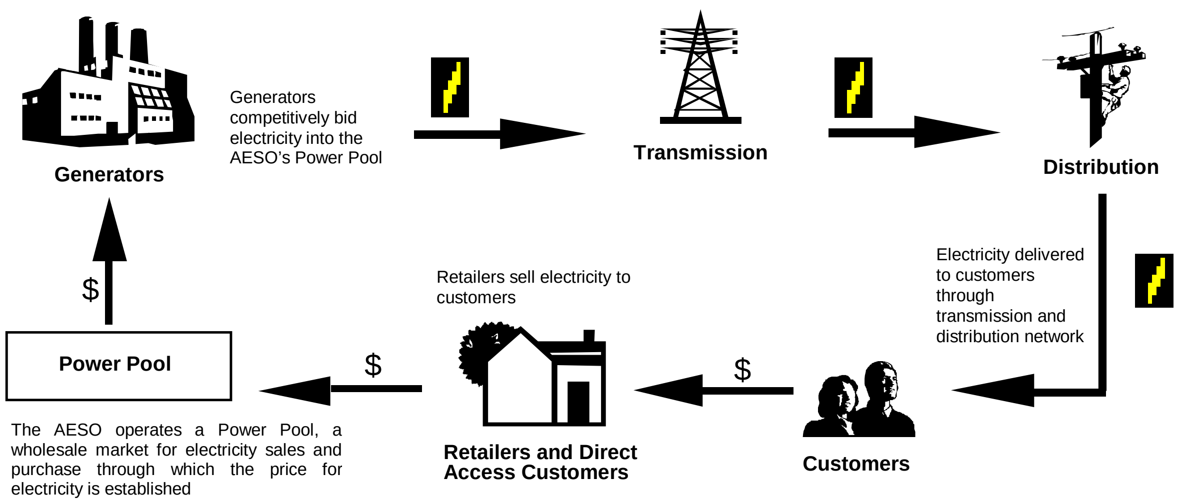
Most of our transmission facilities are situated on lands owned by private landowners, railway companies, industrial customers, and federal and provincial governments, for which we have obtained appropriate land use rights through utility right-of-way agreements, crossing agreements, leases, permits, licences and other agreements. We also own land and office and storage space used in connection with our operations. In addition, we lease office and storage space on customary terms and at market rates.

Overview of Electricity Industry in Alberta

The electricity industry in Alberta consists of four principal segments:

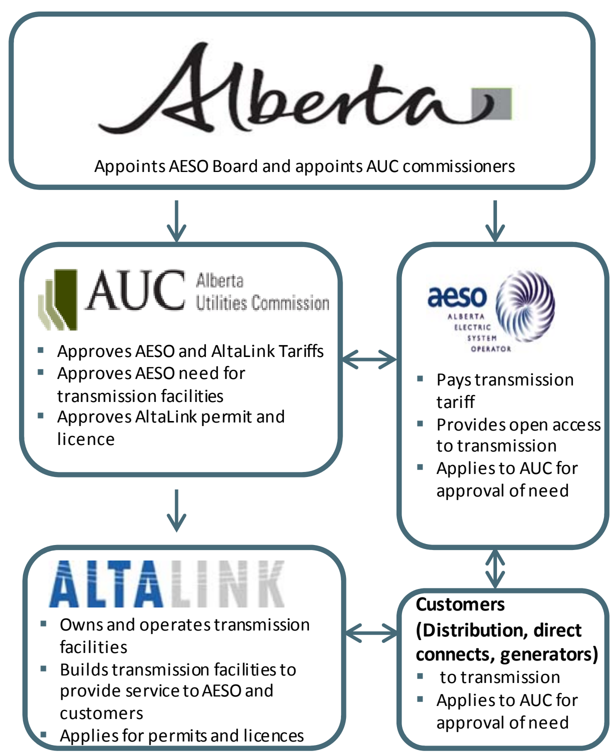
- Generation is the production of electric power. Generators sell wholesale power into the power pool operated by the AESO or through direct contractual arrangements. Most of the power produced in Alberta is generated using coal or natural gas as the fuel source with hydro and wind power adding the majority of the remaining supply.
- Transmission is the conveyance of electricity at high voltages. Alberta's transmission system or grid is operated by transmission facility owners, which are regulated by the AUC, and is composed of high voltage power lines and related facilities which transmit electricity from generating facilities to distribution networks and directly connected end-users.
- Distribution is the conveyance of electricity at lower voltages. Distribution facility owners are regulated by the AUC and are responsible for arranging for, or providing, regulated rate and regulated default supply services to convey electricity from transmission systems and distribution-connected generators to end-use customers. Distribution facility owners are responsible for (i) providing non-discriminatory distribution access and arranging for transmission access for end-use electricity customers, and (ii) constructing and upgrading electricity distribution systems to deliver electricity safely, reliably and efficiently.
- Retailing is the offering for sale or selling of electricity to end-use customers. In Alberta, retailers can procure energy through the Power Pool, through direct contractual arrangements with energy suppliers or ownership of generation facilities and arrange for its distribution to end-use customers. Retailers often bundle the sale of electricity with other services and products. Retailers include "self-retailers" who perform the retailing function on their own behalf. Self-retailers interact with other participants in the Alberta electricity industry, such as distribution utilities, in the same manner as other retailers.

- In Alberta's electricity marketplace, market participants interact in a number of ways. The following diagram represents an overview of this interaction:



We and other transmission facility owners in Alberta are regulated by the AUC as utilities, primarily under the Electric Utilities Act and the Public Utilities Act (Alberta). Under the Electric Utilities Act, we must operate and maintain our transmission facilities in a manner that is consistent with the safe, reliable and economic operation of the transmission system; assist the AESO in carrying out its duties, responsibilities and functions; and provide the AESO with use of our transmission facilities to carry out its duties, responsibilities and functions.

The following diagram outlines our relationships with the AUC, the AESO and other participants in the electricity industry:



Alberta Utilities Commission

The AUC is an independent quasi-judicial agency established by the Alberta Government to regulate and oversee Alberta's electricity industry. The AUC is responsible for ensuring that electrical utility services are delivered fairly, responsibly and in the public interest. In doing so, its duties include:

- Adjudication and Regulation - The AUC regulates and adjudicates issues related to the operation of electric utilities within Alberta;
- General Tariff and other applications - The AUC processes and approves general tariff applications relating to revenue requirements and rates of return for regulated utilities. In determining tariffs, the AUC ensures utility rates are just and reasonable;
- Facilities Applications - The AUC approves new electricity transmission facilities and permits to build and licences to operate electricity transmission facilities;
- Enforcement - The AUC reviews operations and accounts of electric utilities, and conducts on-site inspections to ensure compliance with industry regulations and standards. Through the Market Surveillance Administrator, the AUC adjudicates enforcement issues and may impose administrative penalties when market participants violate AESO Rules; and
- Information and Knowledge - The AUC collects, stores, analyzes, appraises and disseminates information to fulfil its duties.

Alberta Electric System Operator

The Alberta Electric System Operator is an independent system operator that oversees Alberta's Integrated Electrical System and its wholesale electricity market (the Power Pool). The AESO is responsible for directing the safe, reliable and economic operation of the AIES, including long-term transmission system planning.

The system operators at AESO's control centre monitor and operate the AIES to keep the power grid physically stable and balanced by: (i) dispatching electric power generation in Alberta; (ii) scheduling electricity flow with interconnected power grids; and (iii) coordinating real-time operations with transmission facility owners. The physical operation of our transmission facilities can only be performed through our control centre. By law, we must comply with directions from the AESO's control centre unless we consider that there is a real and substantial risk of damage to our transmission facilities or risk to the safety of our employees, the public, or the environment. The AESO also contracts with generation and distribution companies and large industrial consumers of electricity to provide system access services to the AIES.

As operator of the Power Pool, the AESO receives electricity supply offers and demand bids, sets the schedule for dispatching generating plants, reports the Power Pool price for each hour, carries out financial settlement for the electricity exchanged through the Power Pool, and schedules generating plants to provide system support services, such as operating reserve. All electricity entering or leaving the AIES, including electricity imported into and exported from Alberta, is exchanged through the Power Pool. The AESO recovers the cost of market operations through a surcharge on all Megawatt hours traded therein.

We and other transmission facility owners receive all of our transmission tariff revenues from the AESO. The AESO, in turn, charges wholesale tariffs, approved by the AUC, in a manner that promotes fair and open access to the AIES and facilitates a competitive market for the purchase and sale of electricity. The AESO aggregates tariffs paid to all transmission facility owners, costs associated with transmission losses, system support services and other operating costs.

The AESO tariff must ensure that the just and reasonable costs of the transmission system are charged to distribution companies; customers who are industrial systems; customers who have an interval meter, receive electricity directly from the transmission system and have arranged for system access service; and exporters. Except as otherwise provided by the Transmission Regulation, line losses caused by the transmission of electricity are location-based and assessed against suppliers. The AESO's wholesale tariffs are based on the following principles:

- Customer Rates – All end-users (or load customers) are charged the same "postage stamp" tariff for transmission service, regardless of where they are located in Alberta.

- Supplier Rates – All suppliers are charged the same "postage stamp" tariff for transmission service in addition to an adjustment for losses which are location specific.
- Import/Export Rates-All importers or exporters are charged the same "postage stamp" tariff for transmission service in addition to an adjustment for losses which are location specific.

Alberta Reliability Standards

The AESO is currently leading a program for the development and implementation of mandatory reliability standards for planning and operating the AIES and its interties to other jurisdictions. Reliability standards are the planning and operating rules that electric utilities follow to ensure the most reliable system possible. The AESO is a signatory to the Reliability Management System Agreement of the Western Electricity Coordinating Council ("WECC"), which promotes electric system reliability in the western United States, British Columbia, Alberta and Baja California. WECC is the largest of ten regional reliability councils under the North American Electric Reliability Corporation ("NERC"), which is responsible for developing and enforcing mandatory reliability standards in the United States.

In Alberta, the AESO recommends reliability standards for approval by the AUC. The AESO monitors compliance with approved reliability standards, which are binding and enforced by the Market Surveillance Administrator (MSA). The MSA may impose penalties on transmission facility owners, including us, for non-compliance with approved reliability standards.

Transmission Planning and Development

The increasing reliability risks of Alberta's aging transmission system, combined with limited capacity within the system to support the province's economic growth, requires the development of new transmission infrastructure. For more than 30 years there has been limited expansion of the main backbone of the transmission grid in Alberta (transmission lines operating at 240 kV and higher). This lack of expansion, together with an increased demand for electricity and the construction of new generation facilities, has resulted in increased loading and congestion on the transmission system. To cope with these increased demands, we expect that the AESO will direct us and other transmission facility owners to upgrade and expand the transmission system, consistent with:

- The Alberta Government energy strategy, which includes commitments to strengthen Alberta's transmission system;
- The Transmission Regulation, which among other things, requires the expansion and enhancement of the AIES to allow for a congestion-free transmission system that enables the transmission of all anticipated in-merit electricity under normal conditions;
- The Electric Statutes Amendment Act, 2009, as amended; and
- The AESO's Long-Term Transmission System Plans.

Under the Transmission Regulation, the AESO must plan and arrange for expansion and enhancement of the transmission system to allow for a congestion-free transmission system that enables the transmission of all anticipated in-merit electricity under normal conditions. The AESO's responsibilities include long-term transmission planning and management, including assessing the current and future needs of market participants, and planning the capability of the transmission system to meet those needs. Except for critical transmission infrastructure, designated under the Electric Statues Amendment Act, 2009, the AESO determines whether an expansion or enhancement of the transmission system is required. If so, the AESO must file a need application with the AUC for approval. A need application is not required for maintenance upgrades, enhancements or other modifications to existing transmission facilities if it improves efficiency or operation of the transmission facility, but does not materially affect capacity.

The AESO directs us to prepare and submit facility applications to the AUC for permits to construct and licences to operate the transmission facilities to meet the identified need. In some cases, the AESO and we may jointly file need applications and facility applications. Except for critical transmission infrastructure, the AESO generally determines whether we are eligible to prepare and submit Facility Applications based on the geographic area in which we operate. In addition, the Lieutenant Governor in Council may make regulations respecting the determination of who may apply for construction or operation of transmission facilities, including determining who may apply based on a competitive process. Under the Transmission Regulation, the AESO has established rules or practices respecting competitive tenders, the preparation of cost estimates, project scope documents and schedule documents for projects.

Under the Electric Statutes Amendment Act, 2009, in relation to Critical Transmission Infrastructure, the determination of "need" was statutorily vested in the legislature for the Province of Alberta. The Western Alberta Transmission Line (WATL) and Heartland projects, among others, were designated as Critical Transmission Infrastructure under the schedule to that legislation. In December of 2012, the provisions relating to the designation of future Critical Transmission Infrastructure were repealed. The framework for existing Critical Transmission Infrastructure remains in full force and effect.

The Electric Statutes Amendment Act, 2009, included provisions to enable competitive bidding for future Critical Transmission Infrastructure. The AESO filed an application with the AUC seeking approval for its proposed competitive process, which the AESO intends to implement for transmission facilities between the Edmonton and Fort McMurray regions. The AUC approved the AESO application, with conditions, including that the approved process is restricted to those projects currently contemplated in the Electric Statutes Amendment Act (2009) and Transmission Regulation. The AESO also retains the ability to cancel the competitive process under certain conditions.

Major Capital Projects

The AESO's 2011 Long Range Transmission System Plan identified the potential for $13.5 billion in existing and proposed transmission development projects over the next 10 years, to ensure a reliable supply of electricity in Alberta. In addition to the transmission projects for which the AESO has filed a need application, the 10-year transmission system plan also identified additional transmission facilities that could be required depending on how power generation and demand scenarios unfold, including a number of regional upgrades. We expect to develop a significant portion of the plan, as either or both of the AESO's need applications and our facility applications have been filed with the AUC. After the AUC approves our facility applications, we are responsible for constructing and operating the related transmission facilities.

The following table is an overview of the main projects currently in progress.

Project/ Description	Need Application	Facility Application	Status
Southern Alberta Transmission Reinforcement Large scale project to construct transmission lines and substations across southern Alberta to interconnect up to 2,700 MW of proposed wind generation projects. **Stage I**	AUC approved in 2009	• Four applications approved, including Cassils Bowmanton Whitla projects. • One application filed in Q4 of 2012.	• Under construction. • Awaiting AUC hearing.
Stage II	AUC approved in 2009	• Two applications filed in Q4 of 2012. • Multiple applications planned in 2013.	• Awaiting AUC hearing. • Working on future facility applications.

Project/ Description	Need Application	Facility Application	Status
Western Alberta Transmission Line Reinforce system backbone between Edmonton and Calgary with a HVDC transmission line and converter substations.	Approved as CTI in 2009	• Approved in December, 2012.	• Under construction.
Heartland Region Transmission Development Double-circuit 500kV transmission line between the Ellerslie Substation and a new substation in the Gibbons-Redwater area and 240kV loop from the new substation to service industrial load.	CTI designation in 2009	• Approved in 2011.	• Under construction.
Edmonton Region Transmission System Upgrade Debottleneck 240kV system for load growth and decommissioning of coal-fired generation.	AUC approved in 2009	• All applications approved.	• Under construction.
Foothills Area Transmission Development Expand and construct substations and transmission lines in south Calgary region to reinforce local transmission and further interconnect wind energy into the AIES.	Filed in July 2012	• Four applications filed in Q4 of 2012.	• Awaiting AUC hearing.
Yellowhead Rebuild and reinforcement of 138kV system in Yellowhead region.	AUC approved in 2011	• All applications approved.	• Completed in 2012.
Hanna Reinforcements and enhancements of the transmission system in southeastern Alberta	AUC approved in 2011	• All applications approved.	• Under construction.

Southern Alberta Transmission Reinforcement (SATR)

The need for transmission reinforcement in southern Alberta is driven predominantly by the forecast development of wind generation facilities. The AESO has forecast between 2,000 MW and 3,900 MW of wind generation operating in Alberta within the next 10 years, of which between 1,700 MW and 3,200 MW will be situated in southern Alberta. The AESO forecasts include wind generation facilities currently operating in southern Alberta.

In 2009, the AUC approved the AESO's need application for a comprehensive reinforcement of the transmission system in southern Alberta, to be constructed in several stages. Stage I will enable the interconnection of proposed wind generation facilities capable of producing at least 1,200 MW. Subsequent development of Stages II and III would further reinforce the system, consistent with the AESO's growth forecast for wind generation facilities in the region. The AESO has directed us to prepare facility applications for Stages I and II. In the future, the AESO may also direct us to prepare facility applications for Stage III.

We expect the total cost for Stages I and II of the SATR project to be approximately $2.5 billion. As at December 31, 2012, our total capital expenditures related to this project were $590 million.

Stage I

During 2012, we continued construction on the Cassils to Bowmanton and Bowmanton to Whitla facilities, which include 230 kilometres of 240kV transmission lines and two substations, scheduled for completion in 2014 at a cost of approximately $0.8 billion. In 2012, we filed a facility application for the South Foothills Transmission Project, for which we expect the AUC to issue a decision in 2013. We have estimated the total costs of Stage I to be $1.1 billion.

Stage II

During 2012, we filed facility applications for the Medicine Hat and Fidler projects. We plan to file facility applications in 2013 for the remaining elements of Stage II, including the Picture Butte to Etzicom Coulee, Etzikom Coulee to Whitla, and Goose Lake to Etzikom Coulee projects.

Western Alberta Transmission Line

On December 6, 2012, the AUC approved our facility application to construct 350 km of high voltage direct current transmission line and two 1,000 MW converter stations in the Lake Wabamun area west of Edmonton and in the Langdon area east of Calgary. The AESO has extended the in-service date for this project to April 2015 due to extensive procedural delays leading up to the AUC's approval of the project. We have also made significant commitments for the purchase of construction materials and started construction of this project in early 2013. We have estimated the total costs of these facilities to be $1.4 billion. As at December 31, 2012, our total capital expenditures related to this project were $133.7 million.

Heartland Region Transmission Development

As directed by the AESO, we and EPCOR jointly applied for approval of a 500kV line project along the preferred east transportation utility corridor route, as that route crosses the service territories of both utilities. We also filed separate facility applications for certain facilities entirely within our service territory, including the Ellerslie substation expansion, the proposed Heartland substation, and a new 240kV transmission line to interconnect proposed industrial load within the Heartland region. The AUC approved all of these facility applications in November 2011. During 2012, we continued construction activities on the Heartland project and plan to complete these facilities in 2013. The Heartland project includes approximately 65km of 500kV and 22 km of 240kV lines. Our share of the estimated costs of the Heartland facilities is $404 million. As at December 31, 2012, our share of the costs related to this project totalled $156.3 million.

Edmonton Region 240kV Transmission System Upgrades

In February 2009, the AUC approved the AESO's Need Application to reinforce the transmission system in the Edmonton Area to debottleneck transmission capability, to change power system flows due to the retirement of Wabamun Unit #4, and to meet the increasing electrical demand in Edmonton and northeastern Alberta. We have completed or started construction on all elements of the project. We have estimated the total costs of these facilities to be $118 million. As at December 31, 2012, our total capital expenditures related to this project were $84.4 million.

Foothills Area Transmission Development

The Foothills Area Transmission Development project is an integral part of the system required to move wind energy to the load centres of the Foothills and greater Calgary area. The scope of these proposed developments includes various transmission line upgrades, replacements and modifications to existing substations as well as construction of a new Foothills substation. We have estimated the total costs of these facilities to be $413 million. As at December 31, 2012, our total capital expenditures related to this project were $24.0 million.

Yellowhead

During 2012, we completed construction of upgrades to transmission facilities in the Yellowhead region. We estimated the total costs of these facilities to be $140 million. As at December 31, 2012, our total capital expenditures related to this project were $131.0 million.

Hanna

The AUC has approved all three facility applications for this project. All elements of this development are under construction. We estimate the cost of this project to be $298.0 million, with in-service dates in 2013. As at December 31, 2012, we have incurred capital expenditures of $125.0 million.

Other Regional Developments

The AESO has identified the need to upgrade transmission facilities within several geographic regions of Alberta to meet forecast customer load requirements as well as to interconnect future generation projects. This includes projects in the Red Deer, Central-East, Christina Lake and Athabasca regions. We are in the process of estimating the related costs.

Environment, Health and Safety

Environmental Management System

We are committed to meeting all environmental regulatory requirements and to implementing good environmental management practices. The Environmental, Health and Safety Committee of our Board of Directors meets quarterly to review our environmental management system, including our response to environmental, health and safety issues, compliance with applicable legislation, regulatory requirements and industry standards.

We continue to strengthen our environmental management system and are proactive in environmental issues related to our transmission business:

- In 2012, we recycled approximately 265 wooden poles which may otherwise have been sent to a landfill, if we had not signed an agreement with a third party to purchase our used wooden poles for re-use;
- We continued having comprehensive environmental assessments completed by experienced environmental firms to support major project developments;
- We have engaged with the provincial regulatory agencies to develop a streamlined Water Act approval process which will create regulatory approval efficiencies and have a positive impact on project timelines;
- We spent approximately $13.7 million (2011 - $15.8 million) to manage environmental aspects of our business, including environmental assessments for new transmission facilities; and,
- We continued to demonstrate innovation in environmental protection technology by working with Cantega Technologies Inc. and installing their GREENJACKET® protective covers, which has dramatically reduced bird and other wildlife outages at our substations by 95%. We have completed the retrofit of approximately 70 substations to date, and on an annual basis we are retrofitting approximately 10 substations.

All aspects of our Transmission Business are subject to one or more levels of environmental regulation. We believe that we are in material compliance with applicable environmental regulations and approvals. Although primarily regulated at the provincial level, jurisdiction over the environment is also shared by federal agencies and local managing authorities. Federal legislation is the primary regulating authority in situations involving federal lands (e.g. National Parks, First Nations' lands), navigable waters, trans-boundary environmental impacts (e.g. ozone depleting substances), or issues of national concern (e.g. hazardous substances such as polychlorinated biphenyls (PCBs)). The Environmental Protection & Enhancement Act (Alberta) and other provincial legislation apply to all aspects of the construction, operation and maintenance of our transmission facilities.

Under our environmental management system, we identify, manage and mitigate key environmental risks and maintain regulatory compliance through our established operational standards and procedures. We support and enhance the effectiveness of our system through appropriate reporting, record keeping, training and audit processes. Our system is modelled after ISO 14001, the international standard for environmental management systems and includes five broad programs.

Although we cannot predict future changes, if any, to environmental requirements, we expect that costs for ongoing environmental controls and environmental work associated with building new transmission facilities will increase as a result of the significant volume of new projects proposed for our service territory. Because of the manner in which the AUC regulates our tariffs, we expect to recover substantially all of these costs through future revenue requirements.

Chemical & Spill Management

We believe that we are in compliance with current regulations regarding the use of PCBs. The primary risk associated with the use of chemicals at our transmission facilities is the potential for spills or releases of transformer insulating oil. Spills and releases may need to be remediated or monitored, as appropriate, and could trigger regulatory investigations. Fines can result if we do not comply with environmental regulations and standards.

The PCB molecule is extremely stable, which makes it a non-reactive insulating compound but also allows PCBs to persist in the natural environment for a very long time. Trace amounts and low volumes of PCBs are present within some transformers and other auxiliary electrical equipment within substations. When we salvage equipment containing PCBs, all PCB-contaminated oil is removed and sent to hazardous waste facilities. We do not operate any PCB storage facilities.

Our Chemical & Spill program has a number of components designed to manage these risks, including the following:

- We have developed spill response guidelines and trained field personnel;
- We have installed secondary oil containment features at all new transformer locations;
- We track and manage incidents through an incident reporting database;
- We have implemented an SF6 gas inventory process, including the ability to store and reuse gas during maintenance activities; and
- We monitor and analyze transformer oil and PCBs.

Land Management
Our land management program focuses on environmental risks associated with land, including ongoing operations. In addition to managing future contamination risk through our chemical and spill management program, we conduct site inspections to identify and remediate historical contamination risk. We are not aware of any locations where contamination of any significance has migrated off our property. At some locations, surface and shallow depth soil contamination can be found. This type of contamination is consistent with the operation of an active substation, and is generally stable and non-mobile. We will continue to assess, prioritize and remediate contamination risks as required.

Before we purchase any land, we have an independent third party environmental consultant conduct an environmental site assessment to identify any underlying environmental liability. Before selling any land, we ensure that the property meets acceptable standards, assess contamination risks, and provide full disclosure of any known contamination. If a transmission facility is no longer required, we reclaim all land to legislated standards and obtain reclamation certificates from regulatory authorities.

Rights-of-Way Management
Trees coming into contact with transmission lines create both a safety risk and a fire hazard. We use an integrated approach to manage vegetation on rights-of-way, including annual patrols to monitor vegetation growth and assess maintenance requirements. Our vegetation management plan considers site-specific conditions, such as tree density, height, terrain, and adjacent land uses. Where required, we hire licensed contractors to manage vegetation through tree trimming, brush mowing, manual pruning with chain saws, and the use of herbicides. We comply with the Alberta Electrical Communications Utility Code, as well as provincial and federal regulations regarding permits, licensing and herbicide application.

We use herbicides to control vegetation on rights-of-way and within substations. Some herbicides persist in the soil and may have long-term effects on vegetation. We do annual inspections to monitor whether herbicide in any material quantity has migrated from our property or rights-of-way.

Treated Wood Management
Consistent with standard electric utility practice, we purchase wooden power poles treated with wood preserving chemicals such as pentachlorophenol. By increasing resistance to rotting and insect attacks, we significantly extend the service life of wooden power poles to minimize electrical service interruption, reduce pole replacement costs, and optimize the use of wood resources. The wood preservative chemical concentration decreases over time due to biological, chemical and photo degradation. Wood preserving chemicals are a concern if released into the environment through inappropriate pole placement, or the use of substandard poles. Generally, if wood preservatives were to leach from a pole, the chemicals would not migrate farther than approximately 25 centimetres from the pole.

We have implemented standards and operational procedures for our life-cycle approach to managing wooden power poles throughout our transmission facilities and particularly when placing poles in sensitive environmental areas. Trained pole inspectors inspect each pole prior to purchase and during routine line patrols. After poles have been in service for 20 years, we conduct targeted programs to assess structural integrity and apply retreatment chemicals to extend their service lives. We have an agreement with a third party to purchase our poles for re-use. Where possible, we recycle salvaged power poles for reuse as power poles or for other uses. Otherwise, we dispose of salvaged poles at appropriately licensed landfills.

Waste Management
We encourage the reduction, reuse and recycling of wastes through a number of recycling programs, including used transformer insulating oil, salvaged wood poles, paper, aluminium and copper wire, general scrap metal, and battery recycling. General waste and construction waste are delivered to municipal landfill sites through waste service companies.

Electric and Magnetic Fields
All electrical devices, including transmission facilities, emit electric and magnetic fields. We recognize that some people are concerned about potential public health risks associated with exposure to electric and magnetic fields from transmission facilities. We treat those concerns very seriously and continuously monitor scientific research on this subject. After conducting studies and reviews on this issue over the past 30 years, many agencies have not concluded that exposure to electric and magnetic fields from transmission lines causes long-term adverse effects on human, plant or animal health.

We will provide accurate and up-to-date information, including measurements, to the public upon request. During 2012, the volume of requests for information increased as a result of the extensive landowner consultations supporting our capital projects. To meet the needs of our stakeholders, we have increased the resources available to support these activities.

Health and Safety

Culture
The health and safety of our employees and contractors is a core value. We have established a leadership team to provide guidance and oversight with respect to safety. Our ongoing safety management initiatives focus our entire organization on safety accountabilities, responsibilities and culture. We have implemented an annual safety and environment summit to bring together leaders from AltaLink and our contractor community to facilitate learnings across our industry.

Safety Codes
We are committed to public safety and are accredited by the Alberta Safety Codes Council. To maintain our accreditation, we must adhere to a quality management plan that requires us to ensure that all our substation and transmission lines meet or exceed Alberta Electric Utility Code requirements. Alberta Municipal Affairs monitors all accredited companies, municipalities, regional services commissions and corporations for compliance to their quality management plans and safety codes. We are committed to building and maintaining facilities that meet or exceed safety codes.

Non-GAAP Financial Measures

We use certain financial metrics that are not defined under accounting principles generally accepted in Canada, i.e. IFRS. Such "non-GAAP financial measures provide our management and our investors with additional insight into our financial performance and financial condition, expanding on the information that we provide in our financial statements. In particular, our investors, lenders and credit rating agencies use certain non-GAAP financial measures to calculate debt covenants and financial ratios.

We believe that earnings before interest and taxes (EBIT) and earnings before interest, taxes, depreciation and amortization (EBITDA) are useful supplemental measures to analyse our operating performance and to provide an indication of the results generated by our principal business activities prior to the consideration of certain expenses. We use EBITDA to measure our operating performance, before considering our financing strategy or recognizing costs for the consumption and replacement of our capital assets. We also use EBITDA as a proxy for cash provided by operating activities, before considering the effects of non-cash working capital.

Funds from operations (FFO) represents funds generated from operating activities before changes in non-cash working capital. FFO should not be considered to be an alternative to, or more meaningful than, "cash provided by operating activities". We believe that FFO is a useful supplemental measure to analyze our ability to generate cash flow to fund capital investment and working capital requirements.

These non-GAAP financial measures do not have any standardized meaning and therefore are unlikely to be comparable to similar measures presented by other companies.

Financial Position

In the following table, we discuss significant changes (over $50.0 million) in our statement of financial position during the year ended December 31, 2012. Our annual audited Financial Statements include more detailed information regarding the changes in our property, plant and equipment.

	Increase/(Decrease) ($ Millions)	Explanation
Trade and other receivables (Note 5)	70.7	We accrued for amounts due from the AESO for the timing of cash receipts and adjustments to true up the interim transmission tariff. We received the AESO payment for November on January 3, 2013, when due. Settlements of $50.2 million related to the interim transmission tariff were collected on March 1, 2013.
Intangible assets (Note 6)	69.0	We added $77.8 million to construction work-in-progress, offset by $8.8 million in amortization.
Property, plant and equipment (Note 7)	832.3	We added $927.6 million to capital assets and construction work-in-progress, partially offset by $90.4 million in depreciation and $4.9 million of net asset retirements.
Long-term debt maturing in less than one year (Note 11 (b))	240.0	We reclassified $325 million of long-term debt that will mature in June 2013. On January 3, 2012, we repaid $85 million of subordinated notes.
Long-term debt (Note 11(b))	247.7	We issued $575.0 million in new debt, partially offset by the reclassification of $325.0 million of long-term debt and an increase in deferred financing fees.
Deferred revenue (Note 12)	106.6	We transferred $125.5 million of third party deposits and $11.9 million of salvage cost revenue into deferred revenue. We also recognized $14.6 million of revenue to fund salvage costs, and amortized $11.9 million of third party contributions.
Partner's equity (Note 19)	341.3	We received $270.8 million in equity injections from AILP and generated comprehensive income of $107.0 million. We distributed $36.5 million to our partners.

Liquidity and Capital Resources

Liquidity

We generally issue commercial paper to finance our day-to-day cash requirements. The commercial paper program, together with our two lines of credit and anticipated long-term debt issuance, provides us with sufficient liquidity to finance our planned operations and capital projects.

During 2012, we increased our bank credit facilities to an aggregate of $1.5 billion from $0.9 billion. The $1,425.0 million commercial paper backstop facility provides support to our commercial paper program. As at December 31, 2012, $0.0 million of commercial paper was outstanding under our commercial paper program. All bank credit facilities may be used for general corporate purposes. As at December 31, 2012, we had $1,497.6 million of liquidity remaining under those facilities. Our liquidity requirements are considerate adequate to accommodate higher capital expenditures and working capital requirements over the next few years.

Our Short Form Base Shelf Prospectus expired in August 2012. On November 9, 2012, we renewed our Short Form Base Shelf Prospectus to $2.5 billion (from $1.3 billion).

We have increased our capital expenditure program significantly, a trend we expect will continue for several years as we move forward with major capital projects assigned to us by the AESO. We plan to finance the projected capital investments, working capital requirements and any maturities of long-term debt through a prudent combination of cash flow from operating activities, new long-term debt, and equity contributions from AILP.

We plan to use our capital markets platform to refinance long-term debt instruments as they mature.

We use short-term interest-bearing instruments with major Canadian banks to invest temporary cash balances and amounts we receive from customers in advance of construction and operating and maintenance charges. We remit to the AESO all investment income related to deposits received from customers for construction projects and retain investment income we earn on deposits received from customers for future operating and maintenance costs.

Liquidity Ratios [1]

		Year ended	
	December 31, 2012	December 31, 2011	December 31, 2010
Interest coverage			
EBIT coverage [2, 3]	**2.48X**	2.39X	2.28X
EBITDA coverage [2, 4]	**3.87X**	3.93X	3.98X
FFO coverage [2, 5]	**2.71X**	2.55X	2.68X
Debt/total capitalization [6]	**57.20%**	56.90%	56.19%

1. Refer to "Non-GAAP Financial Measures" for further information concerning the non-GAAP financial measures used in this table.
2. For the purposes of calculating the coverage ratios, interest expense is gross of the offset for capitalized borrowing costs and excludes amortization of deferred financing fees on debt.
3. EBIT coverage - Income before interest expense and income tax expense (EBIT) divided by interest expense.
4. EBITDA coverage - Income before interest expense, income tax expense, depreciation and amortization (EBITDA) divided by interest expense.
5. FFO coverage - Funds from operations (FFO) divided by interest expense.
6. Debt/total capitalization - Debt includes short-term and long-term debt, excluding deferred financing fees plus outstanding letters of credit divided by total capitalization (debt plus partners' equity). The AltaLink Master Trust Indenture contains a debt/total capitalization covenant with a limit of 75%.

Working Capital

At December 31, 2012, our working capital deficiency was $449.7 million, primarily due to the maturity date of the $325.0 million Series 03-2 debenture, compared with $245.7 million at December 31, 2011. The working capital deficiency includes commercial paper and bank credit. Our commercial paper program is backstopped by our bank revolving credit facility.

In the future, we expect that we will continue to have a working capital deficiency due to our system expansion plans. The electricity transmission industry is a long-cycle capital-intensive business that requires sufficient cash to fund capital expansion projects and planned maintenance. We fund our transmission business from cash provided by operating activities, and to the extent necessary, through equity injections from AILP and borrowings under our commercial paper program or drawing on our committed bank credit facilities.

Cash Flows

	Quarter ended		Year ended	
	December 31, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
(in millions of dollars)				
Cash and cash equivalents, beginning of period	**$ —**	$ 0.5	**$ 15.4**	$ 12.8
Cash flow provided by (used in):				
Operating activities	**31.5**	18.4	**136.8**	142.0
Investing activities	**(325.0)**	(186.0)	**(846.4)**	(545.1)
Financing activities	**302.7**	182.5	**703.4**	405.7
Cash and cash equivalents, end of period	**$ 9.2**	$ 15.4	**$ 9.2**	$ 15.4

Operating Activities

Compared to the same periods in 2011, our cash flow from operating activities increased by $13.1 million and decreased by $5.2 million for the quarter and year ended December 31, 2012, respectively. For the year ended December 31, 2012 the change is due to an increase in trade receivables from the AESO, resulting from the timing of cash receipts and accruals related to the interim transmission tariff, in accordance with standard regulatory practice until the final approval of the transmission tariff. Monthly payments from the AESO have always been received when due, twenty working days following the end of the previous month. The payment for November 2012 was received on January 3, 2013, twenty working days following the month end, and as such was outstanding at the end of the year. Settlements of $50.2 million related to the interim transmission tariff for 2011 and 2012 were recovered on March 1, 2013.

For the quarter ended December 31, 2012, the change is a result of higher cash receipts from other third parties in 2012. The increase is mainly due to amounts recovered from EPCOR for their share of the Heartland project costs.

Cash interest paid has increased from prior periods due to the ongoing issuance of long-term debt and commercial paper to finance our capital program. Changes in other items, including regulatory balances, relate primarily to the accrual for and settlement of deferral accounts and other regulatory balances with the AESO.

Changes in non-cash working capital for the quarter was $41.7 million higher than the comparative quarter and, on a year-to-date basis, $44.3 million lower than the comparative period. The change year-to-date was primarily due to the increase in receivables, which we discussed in more detail in the financial position section, combined with net recoveries from our joint venture partner related to the Heartland project. The change in the quarter is primarily due to a large decrease in payables compared to 2011, offset by an increase in receivables. In 2011, there was a large reclassification of payables to current from non-current in the quarter.

Investing Activities

Compared to the same periods in 2011, our cash flow used in investing activities increased by $139.0 million and $301.3 million for the quarter and year ended December 31, 2012, respectively, primarily due to higher investment in new transmission facilities. We incurred most of our 2012 capital expenditures in connection with major capital projects that we discuss in more detail in the Major Capital Projects section.

Financing Activities

For the quarter ended December 31, 2012, cash flow provided by financing activities increased by $120.2 million compared to the same period in 2011 in order to finance investing activities. AILP contributed equity of $121.0 million and received distributions of $10.0 million from us. During the same quarter in 2011 we repaid $152.5 million under our bank credit facilities, received $70.0 million of equity, and distributed $7.8 million to AILP.

For the year ended December 31, 2012, cash flow provided by financing activities increased by $297.7 million compared to the same period in 2011 in order to finance investing activities. We issued $575.0 million of long-term debt and used the proceeds to repay $85.0 million of subordinated debt and $17.2 million of our commercial paper. AILP contributed $270.8 million of equity and received $36.5 million of distributions from us. During the same period in 2011, we issued $275.0 million of long-term debt, AILP contributed $145.0 million of new equity and we distributed $31.0 million to AILP.

In our Financial Statements we use the direct method to present our cash flow statement. As certain users of our financial statements find the information in the indirect method useful, we have included the indirect method of presenting cash flows from operating activities below. There are no material differences in presentation of cash flow from investing and financing activities.

	Three months ended		Year ended	
	December 31, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
(in millions of dollars)				
Cash flows from operating activities				
Net income	**$ 32.2**	$ 30.7	**$ 108.2**	$ 85.8
Adjustments for:				
Depreciation and amortization	**31.3**	31.3	**99.2**	93.1
Third party contribution revenue	**(4.0)**	(2.4)	**(11.9)**	(9.2)
Loss/(gain) on disposal of assets	**2.0**	5.3	**2.1**	5.9
Finance costs	**20.7**	23.9	**73.0**	62.3
Change in other items	**(9.7)**	1.4	**(2.3)**	(21.9)
Interest paid	**(30.7)**	(19.8)	**(72.7)**	(59.5)
Funds from operations	**41.8**	70.4	**195.6**	156.5
Change in non-cash working capital items	**(10.3)**	(52.0)	**(58.8)**	(14.5)
Net cash provided by operating activities	**$ 31.5**	$ 18.4	**$ 136.8**	$ 142.0

Earnings Coverage

	Year ended		
	December 31, 2012	December 31, 2011	December 31, 2010
Earnings-to-interest coverage on total debt [1,2]	**2.11 X**[3]	2.08X	1.99X

1. Earnings-to-interest coverage on total debt is a non-GAAP financial measure. As a result of distributing securities by way of a medium-term note program using the debt shelf procedures, we must include updated earnings coverage ratios in conjunction with our financial statements. Refer to "Non-GAAP Financial Measures" for further information concerning the non-GAAP financial measures used in this MD&A.
2. Earnings-to-interest coverage on total debt equals income before interest expense (including amortization of deferred financing fees) on all indebtedness and income taxes divided by annual interest requirements on long-term debt (including capitalized interest). We calculate this ratio by giving pro-forma effect to any long-term debt issued during the period and the use of the proceeds from such long-term debt issues.
3. Our interest requirement on short and long-term debt for the twelve months ended December 31, 2012 was $85.5 million (December 31, 2011 - $70.7 million; December 31, 2010 - $59.2 million), including the pro-forma effect of interest payable on the Series 2011-1 notes issued in November 2011, the Series 2012-1 notes issued in June 2012 and the Series 2012-2 notes issued in November, 2012. Our earnings before interest and income tax for the twelve months ended December 31, 2012, for the purposes of calculating this ratio, were approximately $180.7 million (December 31, 2011 - $146.8 million; December 31, 2010 - $118.1 million).

Credit Ratings

	December 31, 2012	Year ended December 31, 2011	December 31, 2010
DBRS – Commercial paper[1]	**R-1 (low)**	R-1 (low)	R-1 (low)
DBRS – Senior secured bonds and medium-term notes[1]	**A**	A	A
Standard & Poor's-Senior secured bonds and medium-term notes[2]	**A-**	A-	A-

1. On August 17, 2012, DBRS confirmed the above ratings, both with Stable trends.
2. On June 15, 2012, Standard & Poor's confirmed the above rating with a Stable trend.

Commitments

	Total	Payments due by periods: Less than 1 year	1-3 years	4-5 years	After 5 years
(in millions of dollars)					
Short and long-term debt	**$ 1,800.0**	**$ 325.0**	**$ —**	**$ —**	**$ 1,475.0**
Operating leases	**45.5**	**4.3**	**8.3**	**8.3**	**24.6**
Total contractual obligations	**$ 1,845.5**	**$ 329.3**	**$ 8.3**	**$ 8.3**	**$ 1,499.6**

Our contractual commitments for the purchase of property, plant and equipment as at December 31, 2012 are $1,434.0 million. Almost all of these commitments are with SNC-Lavalin ATP Inc., a wholly-owned subsidiary of SNC.

We are committed to operating leases that have lease terms which expire between 2013 and 2026. Of the total expected minimum lease payments, 94% relates to our head office leases. See Note 21 – *Commitments*, in our Financial Statements.

Results of Operations

Revenue

	December 31, 2012	Year ended December 31, 2011	December 31, 2010
(in millions of dollars)			
Operations	**$ 379.9**	$ 343.2	$ 297.0
Other	**26.7**	22.3	28.4

	December 31, 2012	Quarter ended December 31, 2011	December 31, 2010
(in millions of dollars)			
Operations	**$ 110.8**	$ 116.5	$ 87.5
Other	**9.0**	6.0	8.7

Revenue from operations

Revenue from operations includes all revenue earned from providing electricity transmission services. The principal components of our transmission tariff include recovery of forecast operating costs, deemed income taxes, depreciation and amortization expenses, return on rate base and allowance for funds used during construction (AFUDC).

Compared to the same period in 2011, our revenue from operations increased by $36.7 million for the year ended December 31, 2012, primarily due to additional investments in capital assets. Also, in Decision 2011-453 the AUC permitted us to recover (within the current year's transmission tariff) AFUDC related to capital projects directly assigned to us by the AESO. Previously, we capitalized AFUDC as part of the cost of the related capital assets. Our revenues from operations increased by $46.2 million for the year ended December 31, 2011, compared to 2010, primarily due to similar reasons.

Our revenue for the quarter ended December 31, 2012 decreased by $5.7 million compared to the same period in 2011 as the revenue adjustments arising from Decision 2011-453 were included in the results for the fourth quarter of 2011. There were no similar adjustments in 2012.

Other Revenue

Other revenue includes revenue received from third parties, including contributions toward the construction of assets.

Compared to same periods in 2011, cost recovery revenue from third parties increased by $3.0 million and $4.4 million for the quarter and year ended December 31, 2012, respectively. Revenue associated with costs recovered from third parties is received on a cost recovery basis and therefore there is no net income impact. These variances are primarily due to the volume of transmission construction services provided to third parties during these periods, which fluctuates in response to the need for such services and is not predictable. Compared to the same periods in 2010, cost recovery revenue from third parties decreased by $2.7 million for the quarter ended December 31, 2011 and decreased by $6.1 million for the year ended December 31, 2011.

Comprehensive Income

	December 31, 2012	December 31, 2011	December 31, 2010
(in millions of dollars)			
Year ended	**$ 107.0**	$ 85.3	$ 66.3
Quarter ended	**31.3**	30.3	15.5

Our net and comprehensive income for the quarter and year ended December 31, 2012 increased by $1.0 million and $21.7 million, respectively, compared to the same periods in 2011, primarily due to increased investment in electricity transmission infrastructure, and the impact of recent regulatory decisions. Our net and comprehensive income for the quarter and year ended December 31, 2011 increased by $14.8 million and $19.0 million, respectively, compared to the same periods in 2010, primarily due to similar reasons.

Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA)

	December 31, 2012	December 31, 2011	December 31, 2010
(in millions of dollars)			
Year ended	**$ 279.9**	$ 241.5	$ 206.8
Quarter ended	**83.1**	78.7	56.2

Our EBITDA for the quarter and year ended December 31, 2012 increased compared to the same periods in 2011. The reasons for these increases are similar to those noted above for the changes in our comprehensive income for the same periods. Please refer to "Non-GAAP Financial Measures" for more information about how we calculate EBITDA. Our EBITDA for the quarter and year ended December 31, 2011 increased compared to the same periods in 2010. The reasons for these increases are similar to those noted above for the changes in our net income for the same periods.

Operating Expenses

	December 31, 2012	December 31, 2011	December 31, 2010
(in millions of dollars)			
Year ended	**$ 78.9**	$ 73.8	$ 74.4
Quarter ended	**19.3**	19.8	18.6

Our operating expenses include salaries and wages, contracted manpower and, general and administration costs. Our operating expenses for the quarter ended December 31, 2012 decreased by $0.5 million compared to the same period in 2011 due to adjustments recorded in the last quarter of 2011 following receipt of the 2011-12 GTA decision. Our operating expenses for the year ended December 31, 2012 increased by $5.1 million compared to the same period in 2011, due to growth in our transmission system, as well as an increase in cost recovery projects. Our operating expenses for the quarter and year ended December 31, 2011 were comparable to the same periods in 2010. Expenses incurred for cost recovery projects are recovered through revenue and therefore have no net income impact, as discussed under "Other revenue" above.

Property Taxes and Other

	December 31, 2012	December 31, 2011	December 31, 2010
(in millions of dollars)			
Year ended	**$ 45.1**	$ 44.6	$ 44.1
Quarter ended	**14.3**	11.5	14.1

Property taxes, salvage and other expenses are recovered dollar for dollar through regulated deferral and reserve account mechanisms. To the extent that actual costs vary from amounts approved in our tariff, the difference is refunded to or collected from the AESO.

Our property taxes, salvage and other expenses increased for the quarter and year ended December 31, 2012 compared to the same periods in 2011. The increase is primarily due to the timing of salvage costs incurred. Our property taxes, salvage and other expenses increased for the year ended December 31, 2011 compared to 2010. Annual tower payments and property and linear taxes paid and salvage costs incurred increased in 2011 compared to 2010, while 2010 included self insurance reserve and salvage costs related to transmission line repair costs as a result of damage caused by snow storms in southern Alberta. In the fourth quarter of 2010, we included the costs related to the snow storms. As a result, our property taxes, salvage and other expenses were higher in the fourth quarter of 2010 compared to the fourth quarter of 2011.

Depreciation and Amortization

	December 31, 2012	December 31, 2011	December 31, 2010
(in millions of dollars)			
Year ended	**$ 99.2**	$ 93.1	$ 86.9
Quarter ended	**31.3**	31.3	26.1

We calculate depreciation and amortization on a straight-line basis using various rates which are approved by the AUC. Depreciation for the year ended December 31, 2012 increased by $6.1 million compared to the same period in 2011 primarily as a result of an increase in capital projects that have been completed and added to our regulatory rate base partially offset by recording a reduction in depreciation rates approved in Decision 2012-221. Depreciation for the three months ended December 31, 2012 had no change compared to the same period in 2011 due to a decrease in depreciation rates. Depreciation and amortization for the quarter and year ended December 31, 2011 increased compared to the same periods in 2010, primarily due to an increase in capital projects that have been completed and added to our regulatory rate base in 2011.

Finance Costs

	December 31, 2012	December 31, 2011	December 31, 2010
(in millions of dollars)			
Year ended	**$ 73.0**	$ 62.4	$ 46.8
Quarter ended	**20.7**	24.0	14.9

Finance costs include interest costs and amortization of deferred financing fees less capitalized borrowing costs. Our interest expense for the quarter and year ended December 31, 2012 decreased by $3.3 million and increased by $10.6 million, respectively, compared to the same periods in 2011. The lower quarterly finance costs in 2012 relate to the implementation of CWIP in rate base relief in the fourth quarter of 2011, following receipt of Decision 2011-453. In addition, the repayment of the subordinated debenture early in 2012 reduced total interest expense for the year and quarter ended December 31, 2012 relative to the 2011 periods. These reductions were partially offset by the impact of additional debt issued in 2011 and 2012. Our interest expense for the year ended December 31, 2011 increased by $15.6 million compared to the same period in 2010 due to additional debt incurred to finance our capital expenditure program.

Selected Financial Information Derived from our Financial Statements

	December 31, 2012	December 31, 2011	December 31, 2010
(in millions of dollars)			
Net income per unit ($/unit)	**0.322**	0.258	0.202
Funds generated from operations ($ millions)	**195.6**	156.5	139.1
Distributions per unit ($/unit)	**0.110**	0.093	0.084
Total assets ($ millions)	**4,083.7**	3,156.5	2,486.2
Short and long term debt ($ millions) [1]	**1,800.0**	1,331.1	1,037.7

1. The balance is shown before deducting the deferred financing fees, which have been offset against this amount in the Financial Statements, in accordance with generally accepted accounting principles.

Summary of Quarterly Financial Information

Quarter ended	Revenue ($ millions)	Net income ($ millions)	Units outstanding (millions)	Net income per unit ($/unit)
December 31, 2012	119.8	32.2	331.9	0.097
September 30, 2012	97.6	27.3	331.9	0.082
June 30, 2012	96.7	25.9	331.9	0.078
March 31, 2012	92.5	22.9	331.9	0.069
December 31, 2011	122.5	30.7	331.9	0.092
September 30, 2011	82.1	20.6	331.9	0.062
June 30, 2011	84.7	17.1	331.9	0.052
March 31, 2011	76.3	17.4	331.9	0.052
December 31, 2010	96.2	15.5	331.9	0.047
September 30, 2010	81.4	13.4	331.9	0.041
June 30, 2010	79.7	20.3	331.9	0.061
March 31, 2010	68.2	17.1	331.9	0.051

Risk Management

Our transmission business is subject to risks and uncertainties, including those described below. Our goal is to manage these risks to reasonably protect us from unacceptable outcomes including undesirable financial results. You should carefully consider these risk factors and uncertainties in addition to the other information contained in this MD&A, the corresponding financial statements, our annual information form, press releases, material change reports and our other continuous disclosure documents.

Risk Controls and Other Mitigating Measures

We have instituted controls and other mitigating measures to manage the risks we face. Under our risk management program, we conduct risk evaluations to identify and assess our most significant risks and the strategies through which we manage them.

Insurance and Statutory Liability Protection

Our current insurance policies provide coverage for a variety of losses and expenses that could impact our business. This insurance coverage includes general liability, physical loss of or damage to property and boiler and machinery (including substations), directors' and officers' liability, fiduciary liability, employment practices liability, non-owned aircraft liability, and vehicle liability. We believe the extent of this coverage is prudent in the context of our transmission business and utility industry practice, and we anticipate that this coverage will be maintained.

Consistent with past AUC decisions, we do not carry insurance for loss or damage to transmission lines, towers, poles, or physical damage to certain owned vehicles. It is not always possible or economically feasible to insure against all risks on our assets or for other exposure to liabilities, and we may decide not to carry insurance against certain risks as a result of high premiums or for other reasons. In accordance with prudent industry practice and AUC directives, we self insure against certain risks for which commercial insurance is not maintained. In the event of an uninsured loss greater than $100,000, we would apply to the AUC to recover the loss through increased funding to our self-insurance reserve or through an increased tariff.

The Liability Protection Regulation limits our liability in the course of carrying out our duties, responsibilities and functions under the Electric Utilities Act to direct loss or damage arising from our negligence, wilful misconduct or breach of contract. Direct loss or damage is defined in the regulation to exclude loss of profits, loss of revenue, loss of production, loss of earnings, loss of contract or other indirect, special or consequential loss or damage.

Risk Factors and Uncertainties

Despite our initiatives in managing risks, there can be no assurance that one or more of them will not adversely affect our business. Our results of operations, financial position and performance and, accordingly, the value of our outstanding securities, could be adversely affected if we are unable to adequately control or mitigate the effects of such risks on our business.

The following are the more significant items that have an impact on our financial position and results of operations:

Regulated Operations

As a regulated transmission facility owner in Alberta we are subject to the risks normally faced by companies that are regulated. These risks include the approval by the AUC of tariffs, or revenue requirements, that permit a reasonable opportunity to recover on a timely basis the estimated costs of providing service, including a fair return on rate base. In addition, these risks include the disallowance by the AUC of costs incurred.

Our ability to recover the actual costs of providing service and to earn the approved rates of return depends on achieving our forecasts established in the rate-setting process. Actual costs could exceed the approved forecast costs if, for example, we incur operational, maintenance and administration costs above those included in our approved revenue requirement, higher expenses due to maintenance capital expenditures being at levels above those provided for in the tariff decisions, or additional financing charges because of increased debt balances or higher interest rates. The inability to obtain acceptable tariff decisions or to otherwise recover any significant difference between forecast and actual expenses could adversely affect our financial condition and results of our operations.

Project Execution

We manage multiple capital projects to support our operations and the growth of our transmission system. Our ability to execute capital projects depends upon numerous factors that are normally faced by companies executing large construction projects. These factors include, but are not limited to, changes in project scope, the availability and timeliness of regulatory approvals and other required permits, skilled labour availability and productivity, staff resourcing, availability and cost of material and services, design and construction errors, the ability of contractors to deliver on project commitments and the availability and cost of financing.

Some of these typical project risks may be more pronounced for our transmission facility projects. They include the risks associated with the regulatory approval process, which can involve significant landowner opposition and be delayed due to challenges in areas such as route selection, landowner consultation, compliance (including receiving the required environmental or other permits, approvals and certificates from federal, provincial or municipal agencies), and litigation. Transmission facility projects also face increased risk from the anticipated reduction in availability and increase in costs of material and services as the transmission industry across North America and around the world continues to experience high levels of development activity. We also face increased execution risk on projects that rely on or are designed to use technologies that we do not currently use, such as high-voltage direct current, and the implementation of existing technologies in new ways.

These project risks can translate into performance issues and project delays, which under traditional regulatory accounting would delay the receipt of expected cash flows related to a project. Delays in receiving cash flows for large projects could have a material adverse impact on our credit metrics, which are considered by debt rating agencies in assigning a particular rating to our debt securities. This risk was mitigated for 2011 and 2012 because the AUC has approved the use of the CWIP in rate base method in determining our 2011-12 transmission tariffs. While we have applied for continued CWIP in rate base in our 2013-14 GTA, there is no assurance that the AUC will approve our request.

Project risks can also translate into actual project costs being in excess of project cost estimates. We are dependent upon AUC decisions for recovery of the actual project costs of constructing our facilities. We maintain a capital deferral account that is intended to capture the difference between our forecast costs and the actual costs of capital projects for directly assigned projects. The AUC reviews all project costs recorded in our capital deferral account to determine whether the actual costs of projects were prudently incurred. There can be no assurances that all of the actual costs of capital projects will be recovered through an increased revenue requirement approved by the AUC or that a previously approved revenue requirement will not be reduced through the review process. Cost estimates are impacted by market conditions and evolve as the project scope is refined through landowner consultation, route selection, detailed engineering, procurement and construction. By the time the AUC approves a facility application, the estimated project cost may materially exceed the preliminary cost estimates included in the AESO's approved need application. Further, the actual costs of constructing new transmission facilities might exceed the project cost estimates set out in the approved facility application. We cannot predict with certainty how AUC decisions may adversely impact us and there can be no assurance that we can entirely recover the actual costs of directly assigned capital projects through the revenue requirement approved by the AUC. Substantial unrecovered costs could have a material adverse effect on our financial condition and results of our operations.

Regulatory Financial

If the AESO directly assigns the construction of large multi-year transmission facility projects to us, as we currently anticipate, then we would experience increased debt service obligations as a result of significantly increased debt capital levels necessary to fund their construction, but without corresponding additions to our rate-base assets during the construction period for such capital projects. Under traditional regulatory accounting, cash earnings relating to these projects are not realized until the assets are energized into service and added to our rate-base.

Both of our rating agencies, DBRS and Standard & Poors, have identified the scale of our potential capital expenditure program and impact of the traditional regulatory capital accounting methods as risks to maintaining credit metrics in the "A" category over the next several years. In its August 17, 2012 report, DBRS stated that it expects the AUC to continue to allow the Partnership to maintain adequate coverage, cash flow and leverage ratios. Standard & Poors, in their report dated June 15, 2012 also expects our credit metrics to remain at acceptable levels with a negative rating action possible if the company doesn't meet these targets.

While recent AUC decisions are supportive of maintaining our credit profile, there can be no assurances that future decisions of the AUC will continue to provide the necessary support when it is required. If we do not receive the regulatory support necessary to mitigate this regulatory financial risk, then we anticipate that, among other things, the ratings of our debt securities may be downgraded, our access to the necessary capital to finance large transmission projects may be adversely impacted and the cost of capital available to us may be increased.

Reliability

The reliability of our transmission facilities is critical to the customers who depend upon them. Our transmission assets require maintenance, improvement and replacement in order to help ensure their reliable performance. We continually develop capital expenditure programs and assess current and future operating and maintenance requirements for our facilities.

Our ability to reliably deliver power in a cost effective manner is subject to the timeliness of new transmission as planned by the AESO, and the risk of service interruptions from factors that include equipment failure, accidents, severe weather conditions, and other acts of nature, vandalism, sabotage or terrorism. Congestion and constraints on the network remain and continue to grow in certain regions, as new transmission required by the AESO's long term plans to meet generation and load growth in Alberta, has been delayed in various industry approval processes. Power system congestion requires us to operate our aging infrastructure at higher capacities and reduces our opportunities to take facilities out of service for maintenance. As a result, our ability to deliver an acceptable level of reliability to our customers may be adversely impacted.

We base our maintenance programs on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters which are not certain. The inability to obtain AUC recognition (in connection with determining our revenue requirements) of expenditures which we believe are necessary to maintain, improve, or replace our transmission assets, the failure to carry out these maintenance programs on a timely basis, or the occurrence of significant unforeseen equipment failures or damage could have a material adverse effect on us. The costs of repairing or replacing damaged assets, or responding to customer claims, could substantially exceed insurance coverage, if any, and such amounts may not be approved by the AUC for recovery, in whole or in part, through increased tariff revenues. While we may be liable for direct damages to third parties as a result of our negligence, willful misconduct or breach of contract, we expect that the Liability Protection Regulation would shield us from most claims for indirect damages, such as loss of profits or revenue, as a result of service interruptions to our facilities. The effectiveness, however, of this liability protection is subject to the court's interpretation of the regulation, which has not yet occurred.

The AESO has implemented reliability standards and announced its plans to implement additional standards. These reliability standards are enforced by the Market Surveillance Administrator (MSA) who may impose penalties for non-compliance. We expect to recover the costs of implementing and complying with these reliability standards through our tariffs. Penalties imposed by the MSA for non-compliance, may be substantial and we may not be able to recover these costs through our tariff. Such penalties may have a material adverse effect on our financial condition and results of our operations.

Restructuring of Electricity Industry

Deregulation and restructuring of parts of Alberta's electricity industry began in 1996 and is continuing. We are subject to risks associated with changing political conditions and changes in provincial regulations and permitting requirements. It is not possible to accurately predict changes in political conditions, laws or regulations that could impact our operations. The continuing restructuring of the Alberta electricity industry, including the regulatory environment, could have a material adverse effect on our financial condition and results of our operations.

Capital Resources

Our financial position could be adversely affected if we fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. Funds generated from our operations after payment of our expenses (including interest payments on debt) will not be sufficient to fund the repayment of all existing debt when due and anticipated capital expenditures. There may be limitations on the levels of equity capital available to us from AltaLink Investments, L.P. or AltaLink Holdings, L.P. We are substantially wholly owned by AILP and do not use our equity securities as a primary source of capital. Our ability to arrange sufficient and cost-effective debt financing could be affected by numerous factors, including the regulatory environment in Alberta, the results of operations and financial position, conditions in the capital and bank credit markets, our credit ratings, and general economic conditions. Although there has been some easing of global financial conditions, market events continue to show volatility and there is still an environment of relatively tight credit, which reduces available liquidity and overall activity. The inability to access sufficient capital for our operations could have a material adverse effect on our financial condition and results of our operations.

Labour Relations

Approximately 60% of our employees are members of one of two labour unions, the United Utility Workers Association (UUWA) or the International Brotherhood of Electrical Workers (IBEW), which have entered into collective bargaining agreements with our general partner. The provisions of these collective agreements affect the flexibility and efficiency of our business. Our relationships with these labour unions are considered to be satisfactory; however, there can be no assurance that current relations will not change in negotiations or mediation, or that the collective bargaining agreements will not be renewed on acceptable terms. We are in the process of negotiating a renewed collective bargaining agreement with the UUWA, which expired on December 31, 2012. If these events occur, we could face the risks of service interruptions arising from labour disputes or increased labour costs. The inability to recover any significant difference between forecast and actual labour costs could adversely affect our financial condition and results of our operations.

Availability of People

To continuously operate our facilities and grow our business, we must attract and develop sufficient labour and management resources. Like many organizations, we face a demographic shift as large numbers of employees are expected to commence retirement over the next several years. Also, the competition for labour and management resources within the transmission industry is highly competitive as the industry across North America and around the world continues to experience high levels of development activity.

Environment, Health and Safety

We are subject to regulation relating to the protection of the environment, and health and safety, under a variety of federal, provincial and municipal laws and regulations (collectively, "EH&S regulation"). Among other things, spills and leaks can occur in the operation of electric transmission facilities, including accumulations of fluids containing hydrocarbons, PCBs and other contaminants in soil and gravel at substation sites. Electricity transmission itself has inherent potential risks to safety.

Complying with EH&S regulation may require significant expenditures, including costs for cleanup and damages due to contaminated properties, and costs for implementing appropriate training and work safety programs. Failure to comply with EH&S regulation may result in fines and penalties and regulatory authorities may also seek or order the recovery of natural resource damages, injunctive relief or the imposition of stop work orders. We are also exposed to civil and criminal liability for EH&S matters.

Although we do not expect that the costs of complying with EH&S regulation or dealing specifically with environmental liabilities, as they are known today, will have a material adverse effect on our financial condition or results of operations, we have no assurance that the costs of complying with future EH&S regulation will not have a material effect.

Electricity transmission facilities may also cause wildfires as a result of equipment failure, trees falling on a transmission line, or lightning strikes on transmission lines or equipment. We may be liable for firefighting costs, resource damages, and third party claims in connection with such fires. These costs could substantially exceed insurance coverage, if any, and such amounts may not be approved by the AUC for recovery, in whole or in part, through increased tariff revenues. Substantial unrecovered costs could have a material adverse effect on our financial condition and results of our operations.

Electric and Magnetic Fields

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to EMF from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that EMF presents a health hazard, we may face litigation and be required to take mitigation measures. The costs of any litigation, damages awarded and mitigation measures could have a material adverse effect on our financial condition and results of our operations.

Annual Impairment Tests

Any write down in the value of goodwill or other intangible assets as a result of an annual impairment test would result in a non-cash charge that reduces our reported earnings. A write down of any material amount could have an adverse effect on our compliance with any debt to total capitalization tests under our credit facilities or trust indentures. If our credit metrics were adversely impacted, then we anticipate that, among other things, the credit ratings of our debt securities may be downgraded, our access to the necessary capital to finance large transmission projects may be adversely impacted and the cost of capital available to us may be increased.

Competition

In Alberta, our industry has generally operated on the premise that transmission facility owners provide most of the facilities and services required within their respective geographic service territories. However, changes to legislation have been made where the assigning of critical transmission projects may be made through competitive tender regardless of historical service area. In addition, the Lieutenant Governor in Council may make regulations respecting the determination of who may apply for construction or operation of transmission facilities, including determining who may apply based on a competitive process or some other method or process. The AESO applied to the AUC for approval of its proposed framework for competitive bidding. The AUC approved the AESO's application, with conditions. There can be no assurance that any competition related to the provision of transmission services will not have a material adverse effect on our financial condition and results of our operations.

Credit Ratings

Our credit ratings are not recommendations to purchase, hold or sell our debt securities in that such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any credit rating will remain in effect for any given period of time or that our credit ratings will not be revised or withdrawn entirely in the future by the respective credit rating agencies if in their judgment circumstances so warrant. Our credit ratings may not reflect the potential impact of all risks related to our business or our debt securities. In addition, real or anticipated changes in our credit ratings will generally affect the market value of our debt securities. If the credit ratings of our debt securities were downgraded, then we would expect that our access to the necessary capital to finance large transmission projects may be adversely impacted and the cost of capital available to us may be increased.

Transactions with Related Parties

In the normal course of business, we enter into various transactions with AML, AILP, AIML, AHLP and AltaLink Ontario, L.P. We record these transactions at exchange values based on normal commercial rates. AML employs the people who provide administrative and operational services to our business. We have indemnified AML for all associated expenses and liabilities.

We have incurred construction related services costs of $275.1 million and $784.7 million with SNC-Lavalin ATP Inc. during the quarter and year ended December 31, 2012, respectively, compared to $206.0 million and $419.6 million for the comparative periods in 2011. On December 31, 2012, our accounts payable and accrued liabilities included $167.4 million owing to SNC-Lavalin ATP Inc., compared to $143.9 million at December 31, 2011.

On January 3, 2012 we repaid $85.0 million of Series 3 Subordinated Bridge Bonds held by AILP.

Please see note 15 – *Related party transactions* in the Financial Statements for more details.

Legal Proceedings

We have not commenced and are not currently contemplating any material legal proceedings. We are not aware of any material legal proceedings that have been commenced or are being contemplated against us.

On March 28, 2012, the Alberta Court of Appeal granted leave to appeal Decision 2011-436, in which the AUC approved the construction and operation of the Heartland Transmission line and substation. The appellants have limited their appeal to statutory interpretation. The appeal was heard and denied.

In 2012, an application for judicial review was filed with Alberta Court of Queen's Bench relating to the issuance of a permit in the Transportation Utility Corridor by the Minister of Infrastructure. A hearing on this matter took place on January 15-16, 2013. A decision has not yet been rendered.

On January 4, 2013 an application for leave to appeal the AUC Decision on the WATL Project was filed in the Alberta Court of Appeal. The matter has been set for hearing on May 15, 2013.

Off Balance Sheet Arrangements

Disclosure is required of all off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources. We currently have no such off-balance sheet arrangements. Please see note 21–*Commitments* in the Financial Statements for details of capital and lease commitments.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and assumptions that affect amounts reported in the financial statements and accompanying notes. The more significant estimates that have an impact on our financial condition and the results of our operations are disclosed in note 2(d) – *Use of estimates and judgement*, in the Financial Statements.

Contingencies

From time to time we are subject to legal proceedings, assessments and claims in the ordinary course of business. On June 5, 2009, we were served with an action alleging that we and the Plaintiff had concluded a binding agreement for the sale to the Plaintiff of certain lands. At this time, these matters are not reasonably expected to result in a material adverse effect on our financial position or financial performance.

Accounting Changes

Please see note 3(r) in the Financial Statements for more details regarding our assessment of the impact of the following new or revised standards.

Amendments effective for the year ended December 31, 2012

From January 1, 2012 the following new or revised standards became effective and were adopted by us:

- Amendments to IFRS 7 – *Disclosures - Transfers of financial assets*
- Amendments to IAS 1 – *Presentation of financial statements*
- Amendments to IAS 12 – *Income taxes*

The above amendments had no significant impact on our financial statements.

Future Accounting Changes That May Impact Our Financial Statements

New standards effective for the year ending December 31, 2013

From January 1, 2013 the following new standards will become effective:

- IFRS 10 – *Consolidated financial statements*
- IFRS 11 – *Joint arrangements*,
- IFRS 12 – *Disclosure of interests in other entities*
- IFRS 13 – *Fair value measurement*

We do not expect that adopting these standards will have a significant impact on our financial statements.

Amendments effective for the year ending December 31, 2013

From January 1, 2013 the following amendments to standards are effective:

- Amendments to IAS 1 – *Presentation of financial statements*
- Amendments to IAS 19 – *Employee Benefits*
- Amendments to IFRS 7 – *Disclosures – Offsetting financial assets and liabilities*
- Annual Improvements Project for 2009-2011

We do not expect that adopting these standards will have a significant impact on our financial statements.

Effective after 2013

The following new or revised standards will become effective after 2013:

- IFRS 9 - *Financial instruments: Classification and measurement*. We are evaluating the potential impact on our financial statements. Currently, we do not expect that adopting this standard will have a significant impact on our financial statements.
- Amendments to IAS 32 - *Financial instruments: Presentation*. We do not expect that adopting these amendments will have a significant impact on our financial statements.

Update on the IASB work plan and rate-regulated project

The IASB decided on December 17, 2012 to develop an interim standard to provide temporary guidance on rate-regulated activities for first time adopters of IFRS. The IASB further discussed its proposals for an interim standard on January 29, 2013. At this meeting, the IASB discussed grandfathering of existing recognition and measurement policies for those entities that currently recognize regulatory deferral accounts in their financial statements. The scope of the interim standard will be widened compared to the Exposure Draft that was issued in 2009 to capture more regulatory regimes. The interim standard is expected to be finalized by the end of 2013.

Forward Looking Information

Prospective investors should be aware that this MD&A contains certain statements or disclosures that may constitute forward-looking information under applicable securities laws. All statements and disclosures, other than those of historical fact, which address activities, events, outcomes, results or developments that we anticipate or expect may or will occur in the future (in whole or in part) should be considered forward-looking information. In some cases, forward-looking information can be identified by terms such as ”anticipate”, ”believe”, “contemplate”, “continue”, “could”, “enable”, “expect”, “forecast”, “future”, “intend”, “may”, “plan”, “potential”, “will” or other comparable terminology. Forward-looking information presented in such statements or disclosures may, without limitation, relate to: applications to the AUC for approval of, among other things, our revenue requirements (including deferral and reserve accounts, capital structure and return-on-equity, financing plans, treatment of costs for applicable test periods including income taxes, operating expenses, depreciation, capital costs for direct assigned projects and maintenance programs, financing costs related to long-term debt and short-term borrowing and projected growth in our rate base and assets under construction); transmission system expansion forecasts; the anticipated direct assignment of transmission development projects to us from the AESO pursuant to approved need applications or, in the case of critical transmission infrastructure, our eligibility to submit facility applications pursuant to designations by the Government of Alberta or competitive bidding processes; the timing and development of transmission projects and the anticipated capital costs of such projects; business strategy, plans and objectives of management for future operations; forecast business results; the achievement of certain operational and performance measures and the resulting effect on compensation of executive officers; and our anticipated financial performance or condition.

Various factors or assumptions are typically applied in drawing conclusions or making the forecasts or projections set out in forward-looking information. These factors and assumptions include, but are not limited to:

- no changes in the legislative and operating framework for Alberta's electricity market that are adverse to us;
- decisions from the AUC concerning outstanding tariff and other applications that are consistent with past regulatory practices and decisions and are obtained in a timely manner;
- approved rates-of-return and deemed capital structures for our transmission business that are sufficient to foster a stable investment climate;
- a stable competitive environment;
- obtaining sufficient capital on acceptable terms to finance our transmission system expansion; and,
- no significant event occurring outside the ordinary course of business such as a natural disaster or other calamity.
- These assumptions and factors are based on information currently available to us including information obtained by us from third-party industry analysts. In some occurrences, material assumptions and factors are presented or discussed elsewhere in this document in connection with the statements or disclosure containing the forward-looking information. We caution prospective investors that the foregoing list of material factors and assumptions is not exhaustive.

The forward-looking information in statements or disclosures in this MD&A is based (in whole or in part) upon factors which may cause our actual results, performance or achievements to differ materially from those contemplated (whether expressly or by implication) in the forward-looking information. These factors are based on information currently available to us including information obtained by us from third-party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the risks associated with being subject to extensive regulation including risks associated with AUC action or inaction;
- the risk that the AUC does not provide specific relief to sustain our credit metrics over a growth period characterized by large, multi-year transmission facility projects;
- the risk that transmission projects are not directly assigned to us by the AESO or that we are not designated for filing a facility application;
- the risk that we are not able to arrange sufficient, cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risk that system expansion plans are delayed;
- the risks that the actual costs of completing a transmission project significantly exceed estimated costs;
- the risks to our facilities posed by severe weather, other natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the potential for service disruptions and increased costs if we fail to maintain and improve our aging asset base; and
- the risks associated with forecasting our revenue requirements and the possibility that we could incur operational, maintenance or administrative costs above those included in our approved revenue requirement.

We caution prospective investors that the above list of risk factors is not exhaustive. Other factors, which could cause our actual results, performance or achievements to differ materially from those contemplated (whether expressly or by implication) in the forward-looking statements or other forward-looking information, are disclosed in our publicly filed disclosure documents, including those disclosed under "Risk Factors and Uncertainties" in this MD&A and in our Annual Information Form. Risk factors that could lead to such differences include, without limitation:

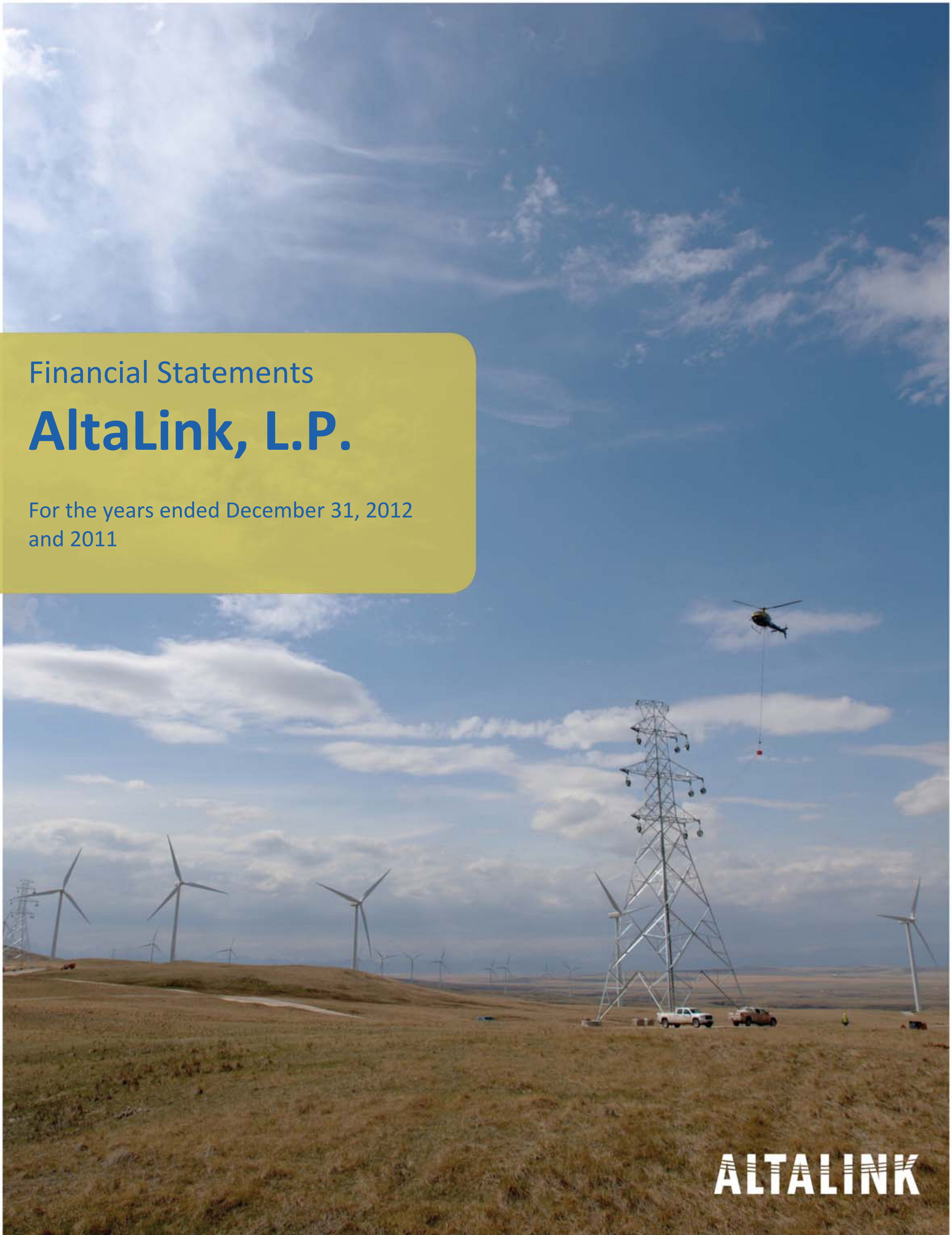
- legislative and regulatory developments that could affect costs or revenues;
- the speed and degree of competition entering the market;
- global capital markets conditions and activity;
- timing and extent of changes in prevailing interest rates;
- currency exchange rates;
- inflation levels and general economic conditions in geographic areas where we operate;
- results of financing efforts;
- changes in counterparty risks; and
- the impact of accounting standards issued by standard setters.

All forward-looking information is given as of March 1, 2013. We are not obligated to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable laws. Because of these risks, uncertainties and assumptions, readers should not place undue reliance on these forward-looking statements. Any forward-looking information contained in this document is expressly qualified by this statement.

Financial Statements

AltaLink, L.P.

For the years ended December 31, 2012 and 2011



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Independent Auditor's Report

To the Partners of AltaLink, L.P.

We have audited the accompanying financial statements of AltaLink, L.P., which comprise the statements of financial position as at December 31, 2012 and 2011, and the statements of comprehensive income, changes in partners' equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the 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 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 financial statements.

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of AltaLink, L.P. as at December 31, 2012 and 2011, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Accountants
March 1, 2013
Calgary, Canada

Statement of Financial Position

	Notes	As at December 31, 2012	December 31, 2011
(in thousands of dollars)			
ASSETS			
Current			
Cash and cash equivalents		**$ 9,241**	$ 15,408
Trade and other receivables	5	**145,612**	74,928
		154,853	90,336
Non-current			
Goodwill		**202,066**	202,066
Intangible assets	6	**173,942**	104,949
Property, plant and equipment	7	**3,469,990**	2,637,735
Third party deposits	8	**51,991**	95,285
Other non-current assets	9	**30,891**	26,174
		$ 4,083,733	$ 3,156,545
LIABILITIES AND PARTNERS' EQUITY			
Current			
Trade and other payables	10	**$ 263,380**	$ 222,006
Commercial paper and bank credit facilities	11(a)	**1,778**	18,981
Long-term debt maturing in less than one year	11(b)	**325,000**	85,000
Current portion of deferred revenue	12	**14,430**	10,036
		604,588	336,023
Non-current			
Long-term debt	11(b)	**1,466,979**	1,219,244
Deferred revenue	12	**587,695**	481,094
Third party deposits liability	8	**51,991**	95,285
Other non-current liabilities	13	**22,578**	16,252
		2,733,831	2,147,898
Commitments and contingencies	21, 22		
Partners' equity		**1,349,902**	1,008,647
		$ 4,083,733	$ 3,156,545

See accompanying notes to the financial statements.

Approved on behalf of the Board of Directors

"David Tuer"

David Tuer
Director

"Patricia Nelson"

Patricia Nelson
Director

ALTALINK

Statement of Comprehensive Income

	Notes	Year ended December 31, 2012	December 31, 2011
(in thousands of dollars)			
Revenue			
Operations	16	**$ 379,893**	$ 343,206
Other	17	**26,735**	22,348
		406,628	365,554
Expenses			
Operating	18(a)	**(78,948)**	(73,819)
Property taxes, salvage and other	18(b)	**(45,103)**	(44,574)
Depreciation and amortization		**(99,205)**	(93,099)
		(223,256)	(211,492)
		183,372	154,062
Finance costs	11(e)	**(72,994)**	(62,355)
Loss on disposal of assets		**(2,140)**	(5,938)
Net income		**108,238**	85,769
Other comprehensive income			
Actuarial loss	14(e)	**(1,283)**	(462)
Total comprehensive income		**$ 106,955**	$ 85,307

See accompanying notes to the financial statements.

Statement of Changes in Partners' Equity

	Units	Allocation to Limited Partner	Allocation to General Partner	Total Retained Earnings	Partners' Capital	Total
(in thousands)						
As at January 1, 2011	331,904	$ 170,852	$ 52	$ 170,904	$ 638,436	$ 809,340
Total comprehensive income	—	85,299	8	85,307	—	85,307
Equity investment received	—	—	—	—	145,000	145,000
Distributions paid	—	(30,997)	(3)	(31,000)	—	(31,000)
Balance at December 31, 2011	331,904	225,154	57	225,211	783,436	1,008,647
Total comprehensive income	—	106,944	11	106,955	—	106,955
Equity investment received	—	—	—	—	270,800	270,800
Distributions paid	—	(36,496)	(4)	(36,500)	—	(36,500)
Balance at December 31, 2012	**331,904**	**$ 295,602**	**$ 64**	**$ 295,666**	**$ 1,054,236**	**$ 1,349,902**

See accompanying notes to the financial statements.

Statement of Cash Flows

	Note	Year ended December 31, 2012	December 31, 2011
(in thousands of dollars)			
Cash flows from operating activities			
Receipts from AESO		**$ 312,201**	$ 331,081
Receipts from other third parties		**88,091**	16,702
Payments to suppliers and contractors		**(156,535)**	(112,079)
Payments to employees		**(33,564)**	(29,967)
Interest payments		**(72,683)**	(59,537)
Payments to AESO		**(665)**	(4,217)
Net cash provided by operating activities		**136,845**	141,983
Cash flows from investing activities			
Capital expenditures		**(974,737)**	(618,693)
Use of third party contributions		**125,532**	72,912
Proceeds from disposal of assets		**2,805**	726
Net cash used in investing activities		**(846,400)**	(545,055)
Cash flows from financing activities			
Senior debt issued		**575,000**	275,000
Subordinated debt repaid		**(85,000)**	—
Use of commercial paper and bank credit facilities		**(17,203)**	18,981
Distributions paid		**(36,500)**	(31,000)
Equity investment received		**270,800**	145,000
Change in other financing activities	20	**(3,709)**	(2,284)
Net cash provided by financing activities		**703,388**	405,697
Net change in cash and cash equivalents		**(6,167)**	2,625
Cash and cash equivalents, beginning of year		**15,408**	12,783
Cash and cash equivalents, end of year		**$ 9,241**	$ 15,408

See accompanying notes to the financial statements.

1. General information

AltaLink, L.P. (the Partnership or AltaLink) was formed under the laws of the Province of Alberta in Canada on July 3, 2001, to own and operate regulated transmission assets in Alberta. The Partnership's registered office is located at 2611 - 3rd Avenue SE, Calgary, Alberta, T2A 7W7. The Partnership has one limited partner, AltaLink Investments, L.P. (AILP), and is managed by AltaLink Management Ltd. (the General Partner). Although the General Partner holds legal title to the assets, the Partnership is the beneficial owner and assumes all risks and rewards of the assets.

On September 20, 2011, SNC-Lavalin Transmission Ltd. became the sole owner of the Partnership by acquiring Macquarie Transmission Alberta Ltd. , which previously held a 23.08% minority interest.

SNC-Lavalin Group Inc. (SNC) is the ultimate parent of the Partnership.

The Partnership is regulated by the Alberta Utilities Commission (AUC), pursuant to the Electric Utilities Act (Alberta) (EUA), the Public Utilities Act (Alberta), the AUC Act (Alberta), and the Hydro and Electric Energy Act (Alberta). These statutes and their respective regulations cover matters such as tariffs, construction, operations, financing and accounting. The Alberta Electric System Operator (AESO) administers the transmission of all electrical energy through the Alberta Interconnected Electric System in the Province of Alberta.

During the years ended December 31, 2012 and 2011, the Partnership operated solely in one reportable geographical and business segment.

2. Basis of preparation

(a) Statement of compliance

These annual financial statements have been prepared on a going-concern basis in accordance with International Financial reporting Standards (IFRS).

The Partnership has applied the IFRS standards and IFRS Interpretation Committee (IFRIC) interpretations that are currently applicable.

The principal accounting policies adopted to prepare these financial statements are set out below. The financial statements reflect the financial position and financial performance of the Partnership and do not include all of the assets, liabilities, revenues and expenses of the partners.

These financial statements were approved for issue by the Board of Directors on March 1, 2013.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis except for the accrued defined benefit pension liability, provisions, accrued employment benefits liabilities and certain financial assets and liabilities related to regulated activities, which are measured initially at fair value. Financial assets and liabilities related to regulated activities are subsequently measured at amortized cost.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Partnership's functional currency.

(d) Use of estimates and judgement

The preparation of the financial statements requires management to make estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

2. Basis of preparation (cont'd)

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Judgements made by management that have significant effects on the financial statements and estimates with a significant risk of material adjustment in the next year are disclosed, where applicable, in the relevant notes to the financial statements.

Accounting policies are selected and applied in a manner which ensures the resulting financial information satisfies the concepts of relevance and reliability, thereby ensuring the substance of the underlying transactions or other events is reported.

As a regulated utility, the Partnership records certain amounts at estimated values until these amounts are finalized. The Partnership bases its estimates and judgements on historical experience, including experience with regulatory processes, current conditions and various other assumptions that are believed to be reasonable under the circumstances. These factors form the basis for making judgements about the carrying values of assets and liabilities. They are also the basis for identifying and assessing the Partnership's accounting treatment with respect to commitments and contingencies. Examples of significant estimates include:

- Expected regulatory decisions on matters that may impact revenue;
- The recovery and settlement of financial assets and liabilities related to regulated activities;
- Key economic assumptions used in cash flow projections;
- The estimated useful lives of assets;
- The recoverability of tangible and intangible assets, including estimates of future costs to retire physical assets or the recoverability of costs associated with direct assigned projects that have been delayed in the regulatory process;
- The recoverability of intangible assets with indefinite lives, such as goodwill; and
- The accruals for capital projects and payroll.

The Partnership applies changes in estimates prospectively as they result from new information. To the extent that a change in accounting estimate gives rise to changes in assets or liabilities, or relates to an item of equity, the Partnership adjusts the carrying amount of the related asset or liability in the period of the change.

The Partnership discloses the nature and amount of a change in an accounting estimate that has an effect in the current period. It also discloses the nature and amount of a change in an accounting estimate that is expected to have an effect in future periods, except when it is impracticable to estimate that effect, in which case the Partnership discloses the fact.

3. Summary of significant accounting policies

(a) Regulation of transmission tariff

The Partnership operates under cost-of-service regulation in accordance with the EUA. The AUC must provide the Partnership with a reasonable opportunity to recover its prudently incurred and forecasted costs, including operating expenses, depreciation, cost-of-debt, capital and taxes associated with investment, and a fair return on investment. Fair return is determined on the basis of return on rate base and allowance for funds used during construction (AFUDC) for non-direct-assigned projects included in construction work-in-progress (CWIP). As disclosed in Note 16, with effect from January 1, 2011 the AUC has authorized accelerated recovery of AFUDC for direct-assigned projects, which is referred to as "CWIP in rate base". The Partnership applies for a transmission tariff based on forecasted costs-of-service. Once approved, the transmission tariff is not adjusted if actual costs-of-service differ from forecast, except certain prescribed costs for which deferral and reserve accounts are established within the transmission tariff. The transmission tariff is received from the AESO in equal monthly installments. All tariff adjustments arising from deferral or reserve accounts relate to services provided to the AESO during the test years, and settlement of these accounts with the AESO is not contingent on providing future services.

If, in management's judgement, a reasonable estimate can be made of the impact future regulatory decisions may have on the current period's financial statements, such an estimate will be recorded in the current period. When the AUC issues a decision affecting the financial statements of a prior period, the effects of the decision are recorded in the period in which the decision is issued.

3. Summary of significant accounting policies (cont'd)

(b) Revenue recognition

Revenues from regulated activities represent the inflow of economic benefits earned during the period arising in the ordinary course of the Partnership's operating activities. Such revenues are recognized on the accrual basis in accordance with tariffs approved by the AUC, and estimates of services provided but not yet billed to the AESO. The Partnership does not recognize revenue for any portion of tariffs received but not earned. Unearned tariffs are classified as financial liabilities related to regulated activities or deferred revenue in the financial statements.

Other revenue represents revenue received from third parties and includes, but is not limited to, services provided on a cost recovery basis to other utilities. Other revenue is recognized on the accrual basis as the costs are incurred. Rental income from third parties is recognized on a straight-line basis over the lease term.

(c) Financial assets and liabilities related to regulated activities

The regulatory and legal rights and obligations under which the Partnership operates assign the Partnership the right to bill and collect financial assets related to regulated activities in the future from the AESO. The AESO is the Partnership's single counterparty for regulated activities and amounts billed to it by the Partnership are based on specific amounts and timing approved by the AUC. There is no future performance required by the Partnership to recover these amounts. Long-term amounts due from the AESO earn a regulatory return and are discounted at a market rate of interest.

The regulatory and legal rights and obligations under which the Partnership operates also require the Partnership to refund to the AESO certain amounts that have been received in tariff revenue that are greater than its actual expenses. Such financial liabilities related to regulated activities due to the AESO within 12 months are not discounted. Amounts due to the AESO beyond the next 12 months are discounted at a market rate of interest.

(d) Interest in Heartland Region Transmission Development project

The Heartland Region Transmission Development project is a joint operation to construct transmission assets in the Heartland Region. AltaLink has a 50% interest in the joint operation. The Partnership's financial statements include its share of the assets, liabilities, income and expenses of the project, which are classified according to their nature.

(e) Property, plant and equipment

Property, plant and equipment (PP&E) are carried at deemed cost less accumulated depreciation. The initial cost of an asset consists of its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, and for qualifying assets, borrowing costs that are eligible to be recovered over the estimated useful life of the asset. The Partnership capitalizes major replacements and upgrades if these costs extend the life of the asset and the Partnership expects to use these items during more than one period. Maintenance and repair costs are recognized as expenses in the period in which they are incurred.

Depreciation is calculated over the estimated useful lives of assets on a straight-line basis based on depreciation studies prepared by an independent expert. The expected useful lives of the assets are reviewed annually, and if necessary, changes in useful lives are accounted for prospectively.

When an asset is retired or disposed of in the normal course of business, the gain or loss is recognized immediately in the Statement of Comprehensive Income.

Generally, losses or gains are recoverable from/repayable to the AESO through future transmission tariffs. AltaLink recognizes the related amounts in revenue and records the amount as financial assets or liabilities related to regulated activities. Construction work in progress, capital inventory and land are capitalized but not depreciated. These assets are valued at the lower of cost or net realizable value.

Reviews of PP&E to establish whether there has been any impairment are carried out when a change in circumstance is identified that indicates an asset might be impaired.

3. Summary of significant accounting policies (cont'd)

(f) Goodwill

Goodwill represents the excess of the purchase price over the fair value of the net identifiable assets of operations acquired. Goodwill is carried at initial cost less any write-down for impairment. Goodwill is assessed for impairment annually, and more frequently if there is any indication of impairment.

The Partnership's business represents one single cash generating unit. Goodwill is first assessed for impairment and fully written down before any other assets are assessed for impairment.

If goodwill has been fully written down, the Partnership would test other assets for impairment by assessing the value in use in the business as a whole. The estimated future cash flows for the business would be discounted to their present value using a pre-tax discount rate that reflects the risks specific to the business and relevant market assessments of the time value of money. If the carrying amounts of the assets exceeded the recoverable amount of the business, the assets comprising the business as a whole would be considered to be impaired. If impaired, the assets would be written down proportionately to ensure their carrying amounts reflect the recoverable amount and the impairment loss would be recognized immediately in the Statement of Comprehensive Income.

If an impairment loss subsequently reverses, the carrying amounts of assets other than goodwill would be increased to reflect the lesser of the recoverable amount and the carrying amount that would have been determined, had no impairment loss been recognized in prior periods. A reversal of an impairment loss would be recognized immediately in the Statement of Comprehensive Income.

Management performed an annual goodwill impairment test by examining the business and regulatory environment, current market conditions, the ownership structure, financing activities, credit ratings, and interest rates. It performed a discounted cash flow and net fair value analysis, which compared favourably to the carrying amount of goodwill. Management concluded that there have been no significant changes in circumstances during the year, and that the carrying value of the goodwill has not been impaired.

(g) Intangible assets

The Partnership's intangible assets are non-monetary assets without physical substance that can be individually identified and consist of the following:

i. Land rights

The Partnership pays fees to third parties to access, survey, build and maintain transmission facilities on third party land. Land rights are reported at cost less accumulated amortization and any impairments. Land rights are amortized on a straight-line basis at rates based on the estimated useful lives of tangible assets located on these lands. Changes to amortization rates are accounted for on a prospective basis.

ii. Computer software

Computer software includes application software and enterprise resource planning software. Computer software is reported at cost less accumulated amortization. Amortization is calculated on a straight-line basis at rates based on the estimated useful lives of assets. Changes to amortization rates are accounted for on a prospective basis.

(h) Third party deposits

i. Contributions in advance of construction

For certain projects, the AESO requires third parties wishing to interconnect to the Partnership's transmission facilities to contribute their share of capital project costs in advance of construction. The Partnership uses these cash contributions to fund capital expenditures as construction progresses. Third party contributions are recorded as deferred revenue when capital funds are expended and recognized into other revenue over the useful lives of the associated assets.

3. Summary of significant accounting policies (cont'd)

ii. Operating and maintenance charges in advance of construction

Certain third parties are required to provide advance funding for future operating and maintenance costs of assets constructed with third party-contributed funds. After these assets are put into service, these contributions are recorded as deferred revenue and recognized into other revenue as operating costs are incurred over the useful lives of the associated assets.

(i) Cash and cash equivalents

Cash equivalents include investments that are readily convertible into a known amount of cash and have an original maturity of three months or less.

(j) Provisions

Provisions are recognized when the Partnership has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of economic benefits will be required to fulfill the obligation and a reliable estimate can be made of the amount of the obligation. The amount recognized as a provision is the best estimate of the consideration required to settle the present obligation at the Statement of Financial Position date, taking into account the risks and uncertainties surrounding the obligation. If the effect is material, provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognized as a finance cost.

(k) Employee benefit obligations

The General Partner employs staff and provides administrative and operational services to the Partnership on a cost-reimbursement basis. The Partnership bears all of the related expenses and also bears the risk and reward of any pension plans or other staff-related programs which the General Partner establishes. The Partnership has indemnified the General Partner for all costs and liabilities associated with its employment of staff, including any pension liabilities. As such, the employee future benefit plans of the General Partner are reported as if they were provided by the Partnership even though the legal sponsor of the plans and employer of the staff is the General Partner. Current service costs are expensed in the period in which they are incurred.

i. Defined contribution plan

AltaLink's defined contribution plan is a post-employment plan under which the Partnership and employees pay fixed contributions into the plan and the Partnership has no legal or constructive obligation to pay further amounts. Obligations for contributions to the plan are recognized as an expense in the Statement of Comprehensive Income in the periods during which services are rendered by employees.

ii. Defined benefit plans

The cost of the Partnership's defined benefit pension and post-retirement benefits plans is actuarially determined, by plan, using the projected benefit method pro-rated on service and management's assumptions to estimate the expected long-term rate of return on plan assets, discount rates, salary escalation and expected growth rate of health care costs. The liability discount rate is determined based on a portfolio of high-quality corporate bonds with cash flows that match the expected benefit payments under the plan. Market values are used to value benefit plan assets.

Actuarial gains and losses arising from experience adjustments and changes in actuarial assumptions are charged to other comprehensive income in the Statement of Comprehensive Income in the period in which they arise.

Past service costs are recognized immediately in income, unless the changes to the plan are conditional on the employees remaining in service for a specified period of time (the vesting period). In this case, the past service costs are amortized on a straight-line basis over the vesting period.

The defined benefit obligation asset or liability is the difference between the present value of the defined benefit obligation, and the fair value of plan assets out of which the obligation is settled.

3. Summary of significant accounting policies (cont'd)

iii. Short-term employee benefits

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

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

iv. Long-term employee benefits

Long-term employee benefit obligations are measured on a discounted basis and expensed in the Statement of Comprehensive income as the related service is provided.

(l) Short-term and long-term debt

Short-term and long-term debt are measured initially at fair value and subsequently at amortized cost. Costs incurred to arrange long-term debt financing are offset against the debt amount and amortized using the effective interest rate method. The amortization of these charges is included in finance costs.

(m) Income taxes

As a limited partnership, AltaLink does not pay income taxes. Instead, the tax consequences of its operations are borne by its partners on a pro rata basis in proportion to their interest in the Partnership. Accordingly, no income tax expense is recognized in the financial statements. Any reference to income tax in these statements relates to the recovery in transmission tariff revenue of tax expense borne by the partners.

(n) Foreign currency translation

Monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the Statement of Financial Position date. Non-monetary assets and liabilities are translated at exchange rates prevailing at the transaction date. Revenues and expenses are translated at the exchange rate prevailing on the date of the transaction except for depreciation and amortization, which are translated at the exchange rate prevailing when the related assets were acquired. Gains and losses on translation are reflected in income when incurred.

(o) Deferred lease inducements

Deferred lease inducements represent leasehold improvements paid for by the lessors. Deferred lease inducements are amortized on a straight-line basis over the initial terms of the leases, and the amortization is recorded as a reduction of lease expense. The unamortized balance in deferred lease inducements is included in other liabilities.

(p) Leases

All of the Partnership's leases are classified as operating leases. Payments made under operating leases are recognized in the Statement of Comprehensive Income on a straight-line basis over the term of the lease.

(q) Capitalized borrowing costs

Borrowing costs are capitalized if they are incurred in connection with the acquisition or production of a "qualifying asset" for which a considerable period of time is required to prepare the asset for its intended use.

The Partnership borrows funds to provide financing for its capital construction program. Borrowing costs eligible for capitalization are applied to capital expenditures unless the borrowing costs are eligible to be recovered though transmission tariffs in the year in which the costs are incurred. The capitalization rate is based on actual costs of debt used to finance the acquisition or construction of qualifying assets.

3. Summary of significant accounting policies (cont'd)

(r) Adoption of new and revised accounting standards

Amendments to standards effective for the year ended December 31, 2012

IFRS 7 - *Disclosures - Transfers of financial assets,* IAS 1 – *Presentation of financial statements*, and IAS 12 - *Income taxes* have been amended and are effective for the year ended December 31, 2012. These amendments did not have an impact on the Partnership's financial statements or its disclosures.

New standards effective for the year ending December 31, 2013

IFRS 10 - *Consolidated financial statements*, IFRS 11 - *Joint arrangements*, IFRS 12 - *Disclosure of interests in other entities* and IFRS 13 - *Fair value measurement* were issued in May 2011. They replace parts of IAS 27 – *Consolidated and separate financial statements* and IAS 28 - *Investments in associates and joint ventures* and relate to the accounting and disclosure for interests in other entities. IFRS 13 provides guidance on how to measure assets and liabilities at fair value as well as the disclosure required to explain management's assumptions to the reader. It is not expected that adopting these standards will significantly impact the Partnership's financial statements.

Amendments to standards effective for the year ending December 31, 2013

Amendments to IAS 1 – *Presentation of financial statements* were issued by the International Accounting Standards Board (IASB) in September 2011. The amendments relate to the disclosure of other comprehensive income as well as the tax impacts of other comprehensive income. This is not expected to have a significant impact on the Partnership's financial statements.

Amendments to IAS 19 - *Employee benefits* were issued by the IASB in June 2011. The amendments are expected to increase disclosure and presentation in the Partnership's financial statements. Implementing these amendments is not expected to have a significant impact on the Partnership's financial statements.

Amendments to IFRS 7 - *Disclosures - Offsetting financial assets and liabilities* were published jointly by the IASB and Financial Accounting Standards Board in December 2011. The amendments are intended to improve the ability of users of financial statements to compare financial statements prepared in accordance with US GAAP and IFRS. Adopting such amendments is not expected to have a significant effect on the Partnership's financial statements.

In May 2012, the IASB issued a collection of amendments to five standards under its Annual Improvements Project. Amended standards includes IFRS 1 – *First time adoption of International Financial Reporting Standards,* IAS 1 – *Presentation of financial statements,* IAS 16 - *Property, plant and equipment,* IAS 32 – *Financial instruments – Presentation,* and IAS 34 – *Interim financial reporting.* These amendments are not expected to have a significant impact on the Partnership's financial statements.

Effective after 2013

IFRS 9 - *Financial instruments: Classification and measurement* was issued on November 12, 2009 and will replace IAS 39 - *Financial instruments: Recognition and measurement*. IFRS 9 is effective for periods beginning on or after January 1, 2015. The Partnership is evaluating the impact of the amendments on its financial statements as issued, although currently they are not expected to have a significant impact.

Amendments to IAS 32 - *Financial instruments - Presentation* to clarify the application of the offsetting requirements were published in December 2011 to address inconsistencies in current practice. The amendments are effective for periods beginning on or after January 1, 2014, with earlier application permitted. The Partnership does not plan to adopt this amendment early and implementation is not expected to have a significant impact on the financial statements.

4. Risk management and financial instruments

(a) Fair value of financial instruments

Financial Instrument	Designated Category	Measurement Basis	Associated Risks	Fair Value at December 31, 2012
Cash and cash equivalents	Fair value through profit or loss (Held for trading)	Fair value	• Market • Credit • Liquidity	Measured at fair value. Cash and cash equivalents earn interest at floating rates based on daily bank deposit rates.
Trade and other receivables *[note 5]*	Loans and receivables	Initially at fair value and subsequently at amortized cost	• Credit • Liquidity	Carrying value approximates fair value due to short-term nature.
Other non-current assets *[note 9]*	Loans and receivables	Initially at fair value and subsequently at amortized cost	• Credit • Liquidity	Amortized cost or carrying value approximates fair value due to nature of asset.
Trade and other payables *[note 10]*	Other liabilities	Initially at fair value and subsequently at amortized cost	• Liquidity	Carrying value approximates fair value due to short-term nature.
Other non-current liabilities *[note 13]*	Other liabilities	Initially at fair value and subsequently at amortized cost	• Liquidity	Amortized cost or carrying value approximates fair value due to nature of liability.
Debt *[note 11]*	Other liabilities	Initially at fair value and subsequently at amortized cost	• Market • Liquidity	$1,967.1 million. Fair values are determined using quoted market prices (which are classified as level 1 inputs) for the same or similar issues.
Third party deposits *[note 8]*	Fair value through profit or loss (Held for trading)	Fair value	• Market • Credit • Liquidity	Measured at fair value. The cash received is held in short-term investments.
Third party deposits liability *[note 8]*	Other liabilities	Initially at fair value and subsequently at amortized cost	• Liquidity	Carrying value approximates fair value due to the nature of the liability.

The Partnership currently does not use hedges or other derivative financial instruments in its operations.

(b) Credit risk

Credit risk is the risk that a contracting entity will not complete its obligations under a financial instrument and cause the Partnership to incur a financial loss. There is exposure to credit risk on all financial assets included in the Statement of Financial Position. To help manage this risk:

- The Partnership has a policy for establishing credit limits;
- Collateral may be required where appropriate; and
- Exposure to individual entities is managed through a system of credit limits.

The Partnership has a concentration of credit risk as approximately 83% of its trade receivable balance is due from the AESO (December 31, 2011 – 75%). The credit risk is mitigated by the fact that the AESO has been established under the EUA, while the remaining receivables are mostly due from investment grade utilities. In addition, other receivables include a $10.1 million recovery of joint project costs (December 31, 2011 - $21.1 million) due from an investment grade utility pursuant to the terms of the agreement for construction of the Heartland project. The remainder of the accounts receivable is comprised mainly of amounts due from other utilities for tower and land leases and other services.

The Partnership's maximum exposure to credit risk, without taking into account collateral held, equals the current carrying values of cash and cash equivalents, trade and other receivables, financial assets due from the AESO and third party deposits as disclosed in these financial statements.

4. Risk management and financial instruments (cont'd)

(c) Market risk

Market risk is the risk that the fair value of future cash flows of financial instruments will fluctuate because of changes in market prices. Components of market risk to which the Partnership is exposed are discussed below:

i. Interest rate risk

The Partnership does not have significant exposure to interest rate risk. To manage interest rate risk, the Partnership controls the proportion of floating rate debt relative to fixed rate debt. In addition, the Partnership maintains access to diverse sources of funding under its established capital markets platform.

It is the Partnership's practice to finance substantially all of its debt requirements with long-term debt securities for which interest rates are fixed during the entire term of each security, generally ranging from five to thirty years from the date of issue. To manage short-term liquidity requirements, the Partnership has established bank credit facilities under which interest rates may vary daily unless the Partnership elects to issue bankers' acceptances or commercial paper under which interest rates are fixed during the entire term, typically ranging from one week to ninety days from the date of issue. It is the Partnership's practice to issue bankers' acceptances and commercial paper for substantially all of its short-term funding requirements. The Partnership may be exposed to interest rate risk upon the rollover of debt at maturity or the issuance of new debt.

ii. Foreign exchange risk

The Partnership does not have a significant exposure to foreign exchange risk.

(d) Liquidity Risk

Liquidity risk includes the risk that, as a result of the Partnership's operational liquidity requirements:

- It may not have sufficient funds to settle a transaction on the due date;
- It may be forced to sell financial assets below their fair market value; and,
- It may be unable to settle or recover a financial asset at all.

To manage this risk, the Partnership has readily accessible standby credit facilities and other funding arrangements in place; generally uses financial instruments that are tradable in highly liquid markets; and, has a liquidity portfolio structure wherein surplus funds are invested in highly liquid financial instruments. See note 11 – *Debt* for a maturity analysis.

(e) Capital risk management

In managing its capital structure, the Partnership includes partners' capital, retained earnings and short-term and long-term debt in the definition of capital.

The Partnership manages its capital structure in order to reduce the cost of capital for customers and other stakeholders and to safeguard its ability to continue as a going concern. In order to maintain or adjust the capital structure, the Partnership may adjust the amount of distributions paid to partners, return capital to partners or request additional contributions from partners. The Partnership reduces refinancing risk by diversifying the maturity dates of its debt obligations.

Summary of capital structure

	As at			
	December 31, 2012		December 31, 2011	
	(millions)	**%**	(millions)	%
Commercial paper and bank credit facilities	**$ 1.8**	**0.1**	$ 19.0	0.8
Long-term debt, maturing in less than one year	**325.0**	**10.3**	85.0	3.6
Long-term debt, excluding deferred financing fees	**1,476.7**	**46.8**	1,227.1	52.5
Partners' capital	**1,054.2**	**33.4**	783.4	33.5
Retained earnings	**295.7**	**9.4**	225.2	9.6
	$ 3,153.4	**100.0**	$ 2,339.7	100.0

4. Risk management and financial instruments (cont'd)

As at December 31, 2012, the Partnership was subject to externally imposed capitalization requirements under the Master Trust Indenture and the bank credit facilities. These agreements limit the amount of debt that can be incurred relative to total capitalization. The Partnership was in compliance with these requirements as at December 31, 2012.

5. Trade and other receivables

	As at	
(in thousands of dollars)	**December 31, 2012**	December 31, 2011
Trade receivables	**$ 110,140**	$ 33,213
GST receivable	**5,571**	7,990
Recovery of joint project costs	**10,137**	21,121
Prepaid expenses and deposits	**7,928**	5,793
Current portion of financial assets related to regulated activities	**11,836**	6,811
	$ 145,612	$ 74,928

Trade receivables as at December 31, 2012 include $104.3 million due from the AESO resulting from the timing of cash receipts and accruals related to the interim transmission tariff in accordance with standard regulatory practice until the final approval of the transmission tariff. Tariff payments from the AESO are generally due during the following calendar month. The tariff payment for November 2012 was received when due on January 3, 2013. The November payment and the accrual for December ($56.8 million) are included within the trade receivable balance above. On January 30, 2013, the AUC issued Decision 2013-023, authorizing the Partnership to recover the accruals related to 2011 and 2012 interim transmission tariffs ($50.2 million) and the cash was received on March 1, 2013.

Financial assets related to regulated activities include the recovery of certain costs incurred by the Partnership relating to its primary activities that are greater than what has been received to date in tariff revenue. The Partnership has recognized as receivables the expenses to be recovered through the regulatory process. The current portion of such assets reflects the amounts to be recovered within the next twelve months. Included in the December 31, 2012 balance is $6.1 million related to cancelled projects (December 31, 2011 – nil).

Financial assets related to regulated activities also include amounts that have been added to rate base (AFUDC equity, AFUDC debt, and losses on disposals of property, plant and equipment) for regulatory purposes, which will be recovered or repaid in tariff revenue over a period of time, which has been approved by the AUC.

6. Intangible assets

(in thousands of dollars)	Land rights	Computer software	Intangibles in CWIP	Total
Cost				
As at January 1, 2011	$ 51,601	$ 37,674	$ 3,065	$ 92,340
Additions to CWIP	—	—	29,955	29,955
Transfers	3,794	10,428	(14,222)	—
Retirements	(1)	(36)	—	(37)
As at December 31, 2011	55,394	48,066	18,798	122,258
Additions to CWIP	—	—	77,750	77,750
Transfers	5,781	17,518	(23,299)	—
Retirements	—	(608)	—	(608)
As at December 31, 2012	**$ 61,175**	**$ 64,976**	**$ 73,249**	**$ 199,400**
Accumulated amortization				
As at January 1, 2011	$ (1,079)	$ (6,296)	$ —	$ (7,375)
Amortization	(1,054)	(8,916)	—	(9,970)
Retirements	—	36	—	36
As at December 31, 2011	(2,133)	(15,176)	—	(17,309)
Amortization	(1,116)	(7,641)	—	(8,757)
Retirements	—	608	—	608
As at December 31, 2012	**$ (3,249)**	**$ (22,209)**	**$ —**	**$ (25,458)**
Net book value				
As at December 31, 2011	$ 53,261	$ 32,890	$ 18,798	$ 104,949
As at December 31, 2012	**$ 57,926**	**$ 42,767**	**$ 73,249**	**$ 173,942**

Intangible assets in CWIP are not amortized until they are available for use, when they are reclassified to the related asset class.

The Partnership has used the following amortization rates during the year:

	2012	2011
Land rights	**2.13%**	2.00%
Computer software	**11.80%-28.33%**	12.38%-24.32%
Intangibles in CWIP	**Not subject to amortization**	Not subject to amortization

7. Property, plant and equipment

	Lines[1]	Substations[2]	Buildings & equipment[3]	Land & CWIP[4]	Total
(in thousands of dollars)					
Cost					
As at January 1, 2011	$ 735,846	$ 1,026,848	$ 83,790	$ 302,801	$ 2,149,285
Additions to CWIP	—	—	—	658,980	658,980
Transfers	79,117	191,299	20,093	(290,509)	—
Retirements	(2,672)	(6,768)	(551)	(75)	(10,066)
As at December 31, 2011	812,291	1,211,379	103,332	671,197	2,798,199
Additions to CWIP	—	—	—	927,584	927,584
Transfers	182,954	281,771	13,681	(478,406)	—
Retirements	(1,440)	(4,766)	(331)	(9)	(6,546)
As at December 31, 2012	**$ 993,805**	**$ 1,488,384**	**$ 116,682**	**$ 1,120,366**	**$ 3,719,237**
Accumulated Depreciation					
As at January 1, 2011	$ (22,758)	$ (46,452)	$ (7,259)	$ —	$ (76,469)
Depreciation expense	(23,888)	(50,622)	(8,619)	—	(83,129)
Retirements	(892)	(409)	435	—	(866)
As at December 31, 2011	(47,538)	(97,483)	(15,443)	—	(160,464)
Depreciation expense	(23,820)	(56,122)	(10,506)	—	(90,448)
Retirements	342	854	469	—	1,665
As at December 31, 2012	**$ (71,016)**	**$ (152,751)**	**$ (25,480)**	**$ —**	**$ (249,247)**
Net book value					
As at December 31, 2011	$ 764,753	$ 1,113,896	$ 87,889	$ 671,197	$ 2,637,735
As at December 31, 2012	**$ 922,789**	**$ 1,335,633**	**$ 91,202**	**$ 1,120,366**	**$ 3,469,990**

1. Lines – transmission lines and related equipment.
2. Substations – substation and telecontrol equipment.
3. Buildings & equipment – office buildings, vehicles, tools and instruments, office furniture, telephone and related equipment and computer hardware.
4. Land & CWIP – land, capitalized inventory, emergency capital spare parts and CWIP. CWIP is reclassified to the appropriate asset classes when the assets are available for use.

The Partnership capitalized borrowing costs of $0.8 million for the year ended December 31, 2012 ($0.8 million for the year ended December 31, 2011) at a capitalization rate of 4.74% (5.31% for the year ended December 31, 2011). In Decision 2011-453, the AUC approved, for directly assigned projects, the recovery of borrowing costs during the year in which they are incurred, rather than over the lives of the related assets. The borrowing costs related to directly assigned projects have not been capitalized within PP&E, as there are no future economic benefits associated with those borrowing costs.

The Partnership has used the following depreciation rates during the year:

	2012	2011
Lines	**2.48%-4.23%**	2.49%-4.86%
Substations	**2.81%-10.15%**	3.03%-12.09%
Buildings & equipment	**2.65%-21.67%**	2.68%-23.41%
Land and construction work in progress	**Not subject to depreciation**	Not subject to depreciation

8. Third party deposits

	As at December 31, 2012	As at December 31, 2011
(in thousands of dollars)		
Contributions in advance of construction	**$ 44,699**	$ 84,671
Operating and maintenance charges in advance	**7,292**	10,614
	$ 51,991	$ 95,285

Third party deposits are recognized as non-current assets with corresponding non-current liabilities. These deposits have certain restrictions attached and can be used only for their intended purposes (see note 3 (h)).

Third party deposits are held in short-term investments, which are reinvested as needed. These investments earned an effective interest rate of 1.01% at December 31, 2012 (December 31, 2011 – 1.03%). For contributions in advance of construction, all interest received is paid annually to the AESO.

9. Other non-current assets

	As at December 31, 2012	As at December 31, 2011
(in thousands of dollars)		
Non-current portion of financial assets related to regulated activities	**$ 30,891**	$ 26,174

Financial assets related to regulated activities include the recovery of certain costs incurred by the Partnership relating to its primary activities that are greater than what has been received to date in tariff revenue. The Partnership has recognized as receivables the expenses to be recovered through the regulatory process. The non-current portion of such assets reflects the amounts to be recovered beyond the next twelve months.

Financial assets related to regulated activities consist of amounts that have been included in rate base (AFUDC equity, AFUDC debt, and losses on disposals of property, plant and equipment) for regulatory purposes, which will be recovered or repaid in tariff revenue over a period of time, which has been approved by the AUC.

10. Trade and other payables

	As at December 31, 2012	As at December 31, 2011
(in thousands of dollars)		
Trade payables	**$ 229,976**	$ 192,273
Accrued interest on long-term debt	**9,918**	10,280
Other current liabilities	**2,639**	2,306
Current portion of financial liabilities related to regulated activities	**20,847**	17,147
	$ 263,380	$ 222,006

Financial liabilities related to regulated activities include accruals for the repayment of the difference between certain costs that have been incurred by the Partnership relating to its primary activities and what has been received in tariff revenue. The difference will be refunded to the AESO through the regulatory process. The current portion of such liabilities reflects the amounts to be refunded within the next twelve months.

Financial liabilities related to regulated activities consist of amounts for annual tower payments, property taxes, debt and capital costs which have been received in tariff revenue, but for various reasons the capital projects have not progressed as scheduled.

Other current liabilities include accruals for employee benefits and deferred lease inducements.

11. Debt

(a) Commercial paper and bank credit facilities

As at December 31, 2012	**Committed**	**Drawdowns**	**Commercial paper outstanding**	**Letters of credit outstanding**	**Availability**	**Maturity date of facility**
(in thousands of dollars)						
Revolving credit facility	**$ 1,425,000**	**$ —**	**$ —**	**$ —**	**$ 1,425,000**	**December 27, 2014**
Operating line of credit	**75,000**	**1,778**	**—**	**612**	**72,610**	**December 27, 2014**
Total bank credit facilities	**$ 1,500,000**	**$ 1,778**	**$ —**	**$ 612**	**$ 1,497,610**	

As at December 31, 2011	Committed	Drawdowns	Commercial paper outstanding	Letters of credit outstanding	Availability	Maturity date of facility
(in thousands of dollars)						
Revolving credit facility	$ 850,000	$ —	$ 18,981	$ —	$ 831,019	June 30, 2013
Operating line of credit	50,000	—	—	362	49,638	December 14, 2013
Total bank credit facilities	$ 900,000	$ —	$ 18,981	$ 362	$ 880,657	

The revolving credit facility provides support for the borrowing under the unsecured commercial paper program and can also be used for general corporate purposes. Drawdowns under either the revolving credit facility or operating line of credit may be in the form of Canadian prime rate loans or bankers' acceptances. At the renewal date, the Partnership has the option to convert both facilities to one-year term facilities.

(b) Long-term debt

	Effective interest rate	Maturing	As at **December 31, 2012**	December 31, 2011
(in thousands of dollars)				
Series 03-2, 5.430%	5.811%	2013	**$ 325,000**	$ 325,225
Series 2006-1, 5.249%	5.299%	2036	**150,000**	150,000
Series 2008-1, 5.243%	5.354%	2018	**201,674**	201,928
Series 2010-1, 5.381%	5.432%	2040	**125,000**	125,000
Series 2010-2, 4.872%	4.928%	2040	**150,000**	150,000
Series 2011-1, 4.462%	4.503%	2041	**275,000**	275,000
Series 2012-1, 3.990%	4.028%	2042	**300,000**	—
Series 2012-2, 2.978%	3.033%	2022	**275,000**	—
			1,801,674	1,227,153
Series 3, subordinated 8.000%	8.020%	2012	**—**	85,000
			1,801,674	1,312,153
Long-term debt maturing in less than one year			**(325,000)**	(85,000)
			1,476,674	1,227,153
Less: deferred financing fees			**(9,695)**	(7,909)
Long-term debt			**$ 1,466,979**	$ 1,219,244

On June 29, 2012, the Partnership issued $300.0 million of Secured Series 2012-1 Medium-Term Notes under the $1,300.0 million Short Form Base Shelf Prospectus which expired in September 2012. In addition, the Partnership issued $275.0 million of Secured Series 2012-2 Medium-Term Notes on November 27, 2012 under the new $2,500.0 million Short Form Base Shelf Prospectus established on November 9, 2012. The total issuance under the new Short Form Base Shelf Prospectus as at December 31, 2012 was $275.0 million. The new Short Form Base Shelf Prospectus expires in December 2014.

11. Debt (cont'd)

(c) Capital markets platform

The Partnership has implemented a financing structure referred to by the Partnership as the "Capital Markets Platform" to finance the operation, maintenance and development of its assets. The Capital Markets Platform incorporates various debt instruments and borrowings, including term bank debt, revolving bank lines of credit, publicly-issued and privately-placed term debt securities, bankers' acceptances, commercial paper and medium-term notes.

The Master Trust Indenture dated April 28, 2003 between the Partnership, the General Partner and BNY Trust Company of Canada, as trustee, establishes common covenants for the benefit of all lenders under the Capital Markets Platform. The Capital Markets Platform governs all indebtedness, including the ranking and security (if any) of the various debt instruments. Indebtedness is calculated as total short-term and long-term debt, including outstanding letters of credit, and total capital is calculated as equity plus indebtedness. The Partnership is not permitted to borrow other than under the Capital Markets Platform, except in certain limited circumstances and, in any event, not in excess of an aggregate of $20.0 million. One of the principal covenants is that the Partnership cannot become liable for any indebtedness, unless the aggregate amount of all indebtedness does not exceed 75% of the total capitalization.

Under the Indenture, the Partnership may issue two categories of debt, namely (i) senior debt and (ii) subordinated debt. Bonds may be issued as either "Obligation Bonds" (to directly evidence the indebtedness of the Partnership to the holder of such debt) or as "Pledged Bonds" (to be held by the holder as collateral security for the indebtedness specified in the related instrument of pledge). The specific terms and conditions of each series of bonds under the Capital Markets Platform are set forth in the series supplement authorizing the series. It is expected that publicly-issued and privately-placed bonds will be in the form of Obligation Bonds, whereas all other indebtedness of the Partnership under the Capital Markets Platform will be supported by Pledged Bonds.

Collateral for the Senior debt obligations consists of a first floating charge security interest on the Partnership's present and future assets. The bank credit facilities rank equally with Senior debt and all future senior secured indebtedness that is issued by the Partnership.

Senior debt is redeemable by the Partnership at the greater of (i) the prevailing Government of Canada bond yield plus a pre-determined premium, and (ii) the face amount of the debt to be redeemed plus, in each case, accrued and unpaid interest to the date of redemption. The Partnership does not intend to redeem any of its long-term debt prior to maturity, other than the Series 3 Subordinated Bonds, which have already been redeemed.

(d) Scheduled principal repayments

(in thousands of dollars)	
Maturing	
2013	$ 325,000
2014	—
2015	—
2016	—
2017	—
2018 and thereafter	1,475,000

(e) Finance costs

	Year ended	
	December 31, 2012	December 31, 2011
(in thousands of dollars)		
Interest expense	**$ 72,321**	$ 61,493
Amortization of deferred financing fees	**1,444**	1,621
Capitalized borrowing costs	**(771)**	(759)
	$ 72,994	$ 62,355

12. Deferred revenue

(in thousands of dollars)	Third Party Contributions	Deferred Revenue for Salvage	Total
As at January 1, 2011	$ 256,794	$ 174,960	$ 431,754
Transferred from third party deposits	72,912	—	72,912
Received through transmission tariff [note 16]	—	10,437	10,437
Recognized as revenue [notes 17 and 18]	(9,172)	(14,801)	(23,973)
As at December 31, 2011	320,534	170,596	491,130
Transferred from third party deposits	**125,532**	**—**	**125,532**
Received through transmission tariff [note 16]	**—**	**11,897**	**11,897**
Recognized as revenue [notes 17 and 18]	**(11,867)**	**(14,567)**	**(26,434)**
As at December 31, 2012	**$ 434,199**	**$ 167,926**	**$ 602,125**
Current portion			$ 10,036
Long-term portion			481,094
As at December 31, 2011			$ 491,130
Current portion			**$ 14,430**
Long-term portion			**587,695**
As at December 31, 2012			**$ 602,125**

Deposits received from third parties used to finance certain capital construction costs and other charges received in advance are initially recorded as deferred revenue and then subsequently recognized as revenue over the lives of the related assets. Funds provided by the regulator to pay for salvage costs are released into revenue when the associated costs are incurred.

13. Other non-current liabilities

	As at	
(in thousands of dollars)	**December 31, 2012**	December 31, 2011
Accrued employment benefit liabilities	**$ 6,216**	$ 4,461
Other liabilities	**2,756**	1,955
Non-current portion of financial liabilities related to regulated activities	**13,606**	9,836
	$ 22,578	$ 16,252

Financial liabilities related to regulated activities include accruals for the repayment of the difference between certain costs that have been incurred by the Partnership relating to its primary activities and what has been received in tariff revenue. The difference will be refunded to the AESO through the regulatory process. The non-current portion of such liabilities reflects the amounts to be refunded beyond the next twelve months.

Financial liabilities related to regulated activities consist of amounts for annual tower payments, property taxes, debt and capital costs which have been received in tariff revenue, but for various reasons the capital projects have not progressed as scheduled.

The accrued employment benefits liability is discussed in Note 14 - *Post employee benefits obligations.*

14. Post employee benefits obligations

(a) Description

The General Partner employs staff and provides administrative and operational services to the Partnership on a cost reimbursement basis. As part of the purchase of the transmission assets the Partnership assumed pension obligations in respect of transmission employees who are members of the defined benefit plan. The pension obligation was transferred by the Partnership to the General Partner at the value of the pension surplus and the Partnership is credited with any pension income and charged for any pension expense. Any cash funding of the pension plan by the General Partner is reimbursed by the Partnership. The Partnership has indemnified the General Partner for all costs and liabilities associated with its employment of staff, including any pension liabilities. As such the pension is reported as if it is held by the Partnership even though the legal plan sponsor and employer of the staff is the General Partner.

The defined benefit provisions of the plan provide a final average pay type benefit. The defined benefit component requires the employees to contribute 2% of eligible earnings, which includes base salary plus short-term incentive pay. Those members who at the date of the acquisition were covered by the defined benefit component of the plan are continuing in that component, and all other employees and any new employees are covered under a defined contribution component. The defined contribution component of the plan is an 8% employer, and 2% employee funded contribution plan.

The General Partner has a non-registered supplemental pension plan, which is provided to those employees who exceed the income tax limits on maximum pension contributions in a year. Membership in the supplemental pension plan is automatic once registered pension plan contributions have reached the maximum annual amount. Employer contributions to the plan are 8% (2011 – 8%).

Other post retirement benefits include the health and dental coverage provided to some past employees.

(b) Assumptions

The significant actuarial assumptions used in measuring the Partnership's net benefit plan cost are as follows:

The expected return on assets assumption is set based on the plan's target investment policy mix, and management's expectations for equity and fixed income returns over the long-term.

	Year ended			
	December 31, 2012		December 31, 2011	
	Pension	**Other**	Pension	Other
	%	**%**	%	%
Discount rate for funded status	**4.30**	**4.00**	5.50	4.95
Discount rate for expense determinations	**5.20**	**4.80**	5.50	5.20
Expected long-term rate of return on plan assets	**6.00**	**—**	6.75	—
Rate of compensation increase	**3.50**	**—**	3.50	—
Health care cost escalation	**—**	**4.50**	—	4.50
Dental care cost escalation	**—**	**4.50**	—	4.50

14. Post employee benefits obligations (cont'd)

(c) Costs recognized

	Year ended			
	December 31, 2012		December 31, 2011	
(in thousands of dollars)	**Pension**	**Other**	Pension	Other
Current service cost	**$ 88**	**$ 599**	$ 89	$ 526
Interest cost on benefit obligation	**492**	**205**	491	182
Expected return on plan assets	**(544)**	**—**	(592)	—
Past service cost amortization	**—**	**—**	—	47
Defined benefit expense (income)	**36**	**804**	(12)	755
Regulatory adjustment to offset (expense) income	**(36)**	**—**	12	—
Expense	**—**	**804**	—	755
Defined contribution expense of registered pension plan	**5,522**	**—**	4,888	—
Supplemental pension expense	**187**	**—**	159	—
Net expense recognized in the financial statements	**$ 5,709**	**$ 804**	$ 5,047	$ 755

(d) Status of plans

The latest actuarial valuation for funding purposes was done as at December 31, 2010 and extrapolated to December 31, 2012. The effective date of the next required valuation for funding purposes is December 31, 2013. The Partnership expects to contribute $0.3 million to its defined benefit pension plans and $0.2 million to its other post retirement benefit plans in 2013.

	Year ended			
	December 31, 2012		December 31, 2011	
	Pension	**Other**	Pension	Other
(in thousands of dollars)				
Fair value of plan assets				
Balance, beginning of year	**$ 9,004**	**$ —**	$ 8,818	$ —
Employee contributions	**8**	**—**	10	—
Company contributions	**398**	**101**	406	68
Benefit payments	**(361)**	**(101)**	(321)	(68)
Actual return on plan assets	**760**	**—**	91	—
Balance, end of year	**9,809**	**—**	9,004	—
Accrued benefits obligation				
Balance, beginning of year	**9,253**	**3,689**	9,045	3,028
Current service cost	**88**	**599**	89	526
Employee contributions	**8**	**—**	10	—
Benefit payments	**(361)**	**(90)**	(321)	(68)
Interest Cost	**492**	**205**	491	182
Actuarial loss (gain)	**1,442**	**57**	(61)	21
Balance, end of year	**10,922**	**4,460**	9,253	3,689
Funded status				
Funded status - deficit	**(1,113)**	**(4,460)**	(249)	(3,689)
Unamortized past service costs	**—**	**141**	—	141
Supplemental pension plan liability	**(784)**	**—**	(664)	—
Accrued liability, end of year	**$ (1,897)**	**$ (4,319)**	$ (913)	$ (3,548)

The asset mix of the defined benefit component of the pension plan as of December 31, 2012 consists of 56% equity and 44% bonds (December 31, 2011 - 60% equity and 40% bonds).

14. Post employee benefits obligations (cont'd)

(e) Actuarial gains and losses recognized directly in other comprehensive income

The cumulative amounts of actuarial gains and losses recognized in other comprehensive income and included in retained earnings is $2.6 million (2011 - $1.3 million).

	Year ended					
	December 31, 2012			December 31, 2011		
(in thousands of dollars)	**Pension**	**Other**	**Total**	Pension	Other	Total
Net loss arising during the year - post-retirement benefits obligation	**$ 1,226**	**$ 57**	**$ 1,283**	$ 441	$ 21	$ 462

(f) Sensitivity to changes in assumed health care cost trend rates as at December 31, 2012 are as follows:

(in thousands of dollars)	**One Percentage Point Increase**	**One Percentage Point Decrease**
Effect on total service and interest cost	**$ 126**	**$ (105)**
Effect on post-retirement benefits obligation	**643**	**(547)**

15. Related party transactions

As described in note 1 – *General information*, ALP is indirectly owned by SNC. Up until September 20, 2011, Macquarie Transmission Alberta Ltd. shared ownership with SNC. ALP's direct parent company is AILP.

In 2002, the Partnership executed a ten-year contract for engineering, procurement and construction management services. These services are provided to the Partnership by SNC-Lavalin ATP Inc., a wholly owned subsidiary of SNC. The terms and conditions of this contract have been approved by the AUC and are subject to ongoing regulatory oversight.

In its 2011 - 2012 General Tariff Application, the Partnership summarized its plans for a competitive procurement process for Engineering, Procurement and Construction Management (EPCM) services after its 10-year contract with SNC-Lavalin ATP Inc. expired in April 2012. The projects underway and past the Proposal to Provide Service submission stage at the expiry date are expected to be completed by SNC-Lavalin ATP Inc. under the previous contract. On April 30, 2012, the Partnership entered into five-year contracts with two companies, including SNC-Lavalin ATP Inc., to provide EPCM services for future capital projects.

In the normal course of business, the Partnership transacts with its partners and other related parties. The following transactions were measured at the exchange amount:

	Year ended	
(in thousands of dollars)	**December 31, 2012**	December 31, 2011
Interest		
AltaLink Investments, L.P.	**$ 37**	$ 6,800
Employee compensation and benefits		
AltaLink Management Ltd.	**98,550**	85,320
Construction related services		
SNC – Lavalin ATP Inc.	**784,669**	419,609
Cost Recovery for non-regulated activities		
AltaLink Investments, L.P.	**1,128**	275

15. Related party transactions (cont'd)

Amounts included in trade and other payables (receivables) are:

	As at	
(in thousands of dollars)	**December 31, 2012**	December 31, 2011
AltaLink Management Ltd.	**$ 17,120**	$ 14,529
SNC-Lavalin ATP Inc.	**167,434**	143,875
AltaLink Investments, L.P.	**(637)**	1,101

Unless otherwise stated, none of the transactions incorporate special terms and conditions and no guarantees were given or received. Outstanding balances are due on a 30-day term and are usually settled in cash.

On January 3, 2012 the Partnership repaid $85.0 million of Series 3 Subordinated Bridge Bonds held by AILP.

For the years ended December 31, 2012 and 2011, there were no other material related party transactions.

Remuneration of senior management

	Year ended	
(in thousands of dollars)	**December 31, 2012**	December 31, 2011
Salary and other short-term benefits	**$ 3,392**	$ 3,544
Post-employment benefits	**255**	271
Other long-term benefits	**1,627**	1,228
Total for all senior management	**$ 5,274**	$ 5,043

Senior Management includes the President and Chief Executive Officer, Executive Vice President and Chief Financial Officer, Executive Vice President and Chief Operating Officer, Senior Vice President Business Development, Senior Vice President Law, Regulatory and General Counsel, Senior Vice President External Engagement, Senior Vice President Human Resources, Senior Vice President Projects, and Senior Vice President Customer Service.

Salary and other short-term benefits represent actual salary received during the year, annual short-term incentive plan payments based on the achievement of specific predetermined performance goals, and perquisites. Post-employment benefits include the defined contribution pension plan and supplemental pension plan employer contributions. Other long-term benefits include amounts related to retention and long-term incentive plans.

Remuneration of Board of Directors of the General Partner

	Year ended	
(in thousands of dollars)	**December 31, 2012**	December 31, 2011
Total fees earned by Directors	**$ 431**	$ 409

The Board of Directors includes the Chairman of the Board, and eight directors. The members of the Board, who are not representatives of the owners, are paid an annual fee plus a fee for meetings attended and additional retainers for serving on board committees.

Transactions with post-employment benefit plans

The defined benefit plan and defined contribution plan are related parties to the Partnership. The Partnership's transactions with the pension plans include contributions and solvency deficiency payments made to the defined benefit plan. The Partnership has not entered into other transactions with the pension plans, nor does it have any outstanding balances at December 31, 2012.

16. Revenue from operations

On November 18, 2011, the AUC issued Decision 2011-453 with respect to the 2011-2012 GTA. On December 8, 2011 the AUC issued Decision 2011-474 regarding the 2011-2012 Generic Cost of Capital proceeding, which awarded a return on equity of 8.75% and a deemed equity ratio of 37%. On January 30, 2013, the AUC issued Decision 2013-023, finalizing the transmission tariffs for 2011 and 2012. The Partnership's 2011 and 2012 revenue from operations includes its best estimate regarding the implementation of these decisions.

The table below summarizes the timing differences between the approved interim transmission tariff and revenue from operations earned during the year.

	Year ended	
	December 31, 2012	December 31, 2011
(in thousands of dollars)		
Return on rate base	**$ 112,000**	$ 112,000
Recovery of forecast expenses	**206,800**	206,800
Deemed income taxes	**17,400**	17,400
Approved interim transmission tariff	**336,200**	336,200
Receivable/(repayable) directly assigned capital projects related revenue	**42,134**	(2,089)
Repayable property taxes and other	**(5,168)**	(2,071)
Salvage costs transferred to deferred revenue [note 12]	**(11,897)**	(10,437)
AFUDC net of capitalized borrowing costs	**911**	640
Reclassification of loss on disposal of PP&E to financial assets related to regulated activities, less amounts already received through tariff and transfer from deferred revenue for salvage costs incurred	**17,713**	20,963
Revenue from operations	**$ 379,893**	$ 343,206

In Decision 2011-082, issued on March 4, 2011, the AUC approved an interim refundable tariff for 2011 and 2012, pending the issuance of a final decision with respect to the 2011-2013 General Tariff Application. As the AUC did not issue its final decision regarding the Partnership's 2011-2012 transmission tariffs until January 30, 2013, the 2011 and 2012 approved transmission tariffs presented in the table above reflect the interim refundable tariff.

Under the CWIP in rate base method, AFUDC is being recovered through current tariffs rather than over the lives of the related assets. The CWIP in rate base method applies to AFUDC related to projects directly assigned by the AESO. AFUDC related to capital replacement and upgrade projects continues to be capitalised. The AESO is the Partnership's only customer related to regulated activities. The Partnership receives all of its revenue from operations from the AESO, including settlements of all financial assets and liabilities related to regulatory activities.

For the year ended December 31, 2012, approximately 93% of the Partnership's revenue is attributable to the AESO (December 31, 2011– 94%).

17. Other revenue

The Partnership occasionally provides transmission construction services to third parties (primarily other utilities) on a cost recovery basis; therefore there is no net income impact. Related costs are included in operating expenses.

(in thousands of dollars)	Year ended **December 31, 2012**	December 31, 2011
Third party contributions revenue [note 12]	**$ 11,867**	$ 9,172
Costs recovered from third parties	**5,302**	5,473
Services provided to third parties	**4,954**	4,895
Tower, land and other lease revenue	**1,153**	1,253
Related party and other revenue	**3,459**	1,555
	$ 26,735	$ 22,348

18. Expenses

(a) Operating expenses

(in thousands of dollars)	Year ended **December 31, 2012**	December 31, 2011
Employee salaries and benefits	**$ 34,500**	$ 29,700
Contracted labour	**23,200**	24,800
Other operating expenses	**21,248**	19,319
	$ 78,948	$ 73,819

(b) Property taxes, salvage and other expenses

(in thousands of dollars)	Year ended **December 31, 2012**	December 31, 2011
Property and business tax	**$ 22,904**	$ 21,455
Salvage expenses	**14,567**	14,801
Annual structure payments	**6,426**	6,000
Credit facility and hearing expenses	**1,206**	2,318
	$ 45,103	$ 44,574

Property taxes, salvage and other expenses do not have an impact on net income because they are fully recovered in tariff revenue (note 16 - *Revenue from operations*).

19. Partners' equity

The Partnership is authorized to issue an unlimited number of units. The units are voting and participate equally in profits, losses and capital distributions of the Partnership. The Partnership is also authorized to issue preferred partnership units which have the same rights, privileges, restrictions and conditions attached to all other units except that in the event of the liquidation, dissolution or winding-up of the Partnership, holders of each preferred unit are entitled to participate preferentially in any distribution. The Partnership has not issued any preferred units.

The General Partner does not hold any units in the Partnership. It manages the operations of the Partnership, and has a 0.01% interest in the profits, losses and capital distributions of the Partnership.

During the year ended December 31, 2012, the Partners invested additional equity of $270.8 million (December 31, 2011 - $145.0 million). No partnership units were issued during the year ended December 31, 2012 (December 31, 2011 – nil).

20. Other cash flow information

	Year ended	
	December 31, 2012	December 31, 2011
(in thousands of dollars)		
Net change in other financing activities		
Deferred financing fees	**$ (3,709)**	$ (2,284)
Third party deposits	**43,294**	(46,320)
Third party deposits liability	**(43,294)**	46,320
	$ (3,709)	$ (2,284)

21. Commitments

The contractual commitments of the Partnership for the purchase of property, plant and equipment as at December 31, 2012 are $1,434.0 million (December 31, 2011 - $1,062.1 million). Almost all of these commitments are with SNC-Lavalin ATP Inc., a wholly owned subsidiary of SNC (December 31, 2011 – 99%).

The Partnership is committed to operating leases that have lease terms which expire between 2013 and 2026. Of the total expected minimum lease payments, 94% relates to the Partnership's head office leases.

Expected minimum lease payments in future years are as follows:

	As at December 31, 2012
(in thousands of dollars)	
Operating lease obligations payable on non-cancellable leases are as follows:	
No later than 1 year	**$ 4,318**
Later than 1 year and no later than 5 years	**16,555**
Later than 5 years	**24,624**
	$ 45,497

22. Contingencies

From time to time, the Partnership is subject to legal proceedings, assessments and claims in the ordinary course of business. The Partnership was served with an action on June 5, 2009 alleging that the Plaintiff and the Partnership had concluded a binding agreement for the sale to the Plaintiff of certain lands. At this time, in the opinion of management, none of these matters is reasonably expected to result in a material adverse effect on the Partnership's financial position or financial performance.