



Management's Discussion and Analysis

AltaLink, L.P.

February 23, 2012




ALTALINK

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Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reflects events known to us as of February 23, 2012. 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 February 23, 2012, 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, 2011 and 2010 (the Financial Statements) and the notes thereto.

Until December 31, 2010, we prepared our financial statements in accordance with Canadian generally accepted accounting principles (C-GAAP), which differ in some areas from IFRS. This is the first year in which we have prepared annual financial statements under International Financial Reporting Standards (IFRS). We have applied IFRS 1 ("First time Adoption of International Reporting Standards") to prepare the opening statement of financial position as at January 1, 2010, (the Transition Date).

To effect the transition to IFRS in the Financial Statements, we have adjusted certain amounts reported in previous financial statements prepared under C-GAAP, as disclosed in the Financial Statements under Note 24 – "Explanation of transition from Canadian GAAP to IFRS".

Amounts are presented in Canadian dollars unless otherwise stated.

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, 2011, respectively.

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

Executive Summary

2011 Highlights

- We invested $683.9 million (2010 - $477.2 million) on capital projects to reinforce and expand the transmission system;
- We achieved before tax comprehensive income of $85.3 million (2010 - $66.3 million);
- We issued $275.0 million of long term senior debt at 4.462% to finance our capital construction program;
- We started construction on new facilities approved by the Alberta Utilities Commission (AUC) during the year, including the $0.8 billion Cassils Bowmanton Whitla (CBW) projects;
- The AUC issued decisions regarding its Generic Cost of Capital proceeding and our 2011-12 General Tariff Application;
- SNC-Lavalin became our sole owner in September 2011; and
- The AUC approved the facility applications for the Heartland Region Transmission Development Project in November, 2011.

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 (AIES), including interconnections between the AIES and 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. (AILP). Through its indirect ownership in AILP, SNC-Lavalin 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.

Operational Excellence

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, metering, 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

In 2002, we entered into an exclusive 10-year contract with a wholly-owned subsidiary of SNC-Lavalin to provide engineering, procurement and construction (EPCM) services for our capital projects. SNC-Lavalin has significant global experience in the electricity industry including the planning, design and construction of approximately 110,000 kilometres of transmission and distribution lines and approximately 1,600 substations. This strategic outsourcing arrangement enhances our capability to deliver results to consumers by facilitating design and execution of our capital projects in a timely and cost-effective manner.

In our 2011-12 General Tariff Application (GTA), we summarized our plans for a competitive procurement process for EPCM services after the current contract expires in April 2012. These plans include a framework under which SNC-Lavalin will continue, where appropriate, to execute projects we have assigned to them before April 30, 2012. We are in the final stages of an independently monitored competitive procurement process under which we intend to contract for EPCM services.

Organizational Leadership and People

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 650 skilled and dedicated people and are continuing to increase our workforce to deliver on the major transmission projects planned in Alberta.

Approximately 60% of our employees are members of a labour union, belonging to either the United Utility Workers Association (UUWA) or the International Brotherhood of Electrical Workers (IBEW). We are in the process of negotiating a renewed collective bargaining agreement with the IBEW. The UUWA collective bargaining agreement was renewed during 2010 and is valid until December 31, 2012. Since our inception, neither union has engaged in a work stoppage in connection with our business. We consider our working relationship with both unions to be satisfactory, and there are no material outstanding grievances with either union.

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**.**

Stakeholder Engagement

We actively engage our stakeholders by providing them with timely, easy to understand information about our operations and proposed transmission projects and gather their input through a variety of methods to reduce the overall impact on land use and landowners.

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. We have a strong track record in reliability, and continually strive to further reduce the duration of system outages for the benefit of our customers.

	Year ended December 31,		
	2011	2010	2009
Frequency of outages (SAIFI) [1]			
AltaLink	1.04	1.52	0.96
CEA [3]	N/A[3]	1.67	1.72
Duration of outages (SAIDI) [2]			
AltaLink	0.73	1.25	0.64
CEA [3]	N/A[3]	1.53	0.94

1. System Availability Interruption Frequency Index is the average number of interruptions per delivery point during a twelve-month period.
2. System Availability Interruption Duration Index is the average number of interruption hours per delivery point during a twelve-month period.
3. Statistics from the Canadian Electrical Association are provided on a transmission only basis. The CEA results are not yet available for 2011.

We have not adjusted our 2010 results for major storm events that caused significant damage in April 2010. If we had excluded those major storm events from our 2010 results, our SAIFI results would improve from 1.52 to 1.26 and our SAIDI results would improve from 1.25 to 0.66.

Safety

Our safety management initiatives encompass all aspects of our safety systems. We are committed to continuously improving our safety culture and safety management processes. During 2011, our workplace injury frequency rate (AIFR) increased from 0.31 to 0.61 per 200,000 man hours, compared to our record performance in 2010 when we reduced our AIFR from 1.42 in the previous year. Our safety statistics include all man hours worked by contractors and sub-contractors. During 2011, an incident involving one of our sub-contractors resulted in a fatal injury to an employee of one of our sub-contractors.

	Year ended December 31,		
All Injury Frequency Rate [1]	**2011**	2010	2009
AltaLink	0.61	0.31	1.42
CEA [2]	N/A[2]	2.09	2.19

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 2011.

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 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 our revenue based on transmission tariffs approved by the AUC, including adjustments arising from deferral accounts established under regulatory decisions related to those tariffs. During 2011 the AUC issued Decision 2011-453 on our General Tariff Application (GTA Decision) for 2011-2012 and Decision 2011-474 on the Generic Cost of Capital (GCOC Decision), respectively, to be used for 2011. In these decisions, the AUC approved significant measures to mitigate the impact of major capital projects on our credit ratings. Please refer to the GTA and Transmission Tariffs for 2011 and 2012 section of this MD&A for more information.

Growth in Regulated Capital Assets

Growth in our regulated capital assets (both rate base and construction work in progress) 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 construction work in progress 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 construction work in progress; (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	**2011**	2010	2009
(in millions of dollars)			
Mid-year rate base	$ 1,552.2	$ 1,266.9	$ 1,044.3
Mid-year construction work in progress	397.3	306.5	224.3

For the year ended December 31, 2011 our capital program included more than $120 million of capital replacement and upgrade projects and more than $550 million of expansion projects directly assigned to us by the AESO. In our February 21, 2012 compliance filing with the AUC, we forecast our 2012 capital expenditures to be over $900 million. Our actual capital program may vary from our compliance filing, 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.

We finance our capital expenditures through a combination of debt and equity consistent with our deemed capital structure.

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. (AML), as general partner, and AILP, as the sole limited partner. As general partner, AML manages the regulated electricity transmission facilities that we own and operate in the Province of Alberta. Both AILP and its sole limited partner, AltaLink Holdings, L.P. (AHLP), are managed by AltaLink Investments Management Ltd. (AIML).

On September 20, 2011, SNC-Lavalin Inc. became our sole owner when one of its subsidiaries acquired the 23.08% interest in AHLP that was previously held by Macquarie Transmission Alberta Ltd.

Regulated Tariff Revenue

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.

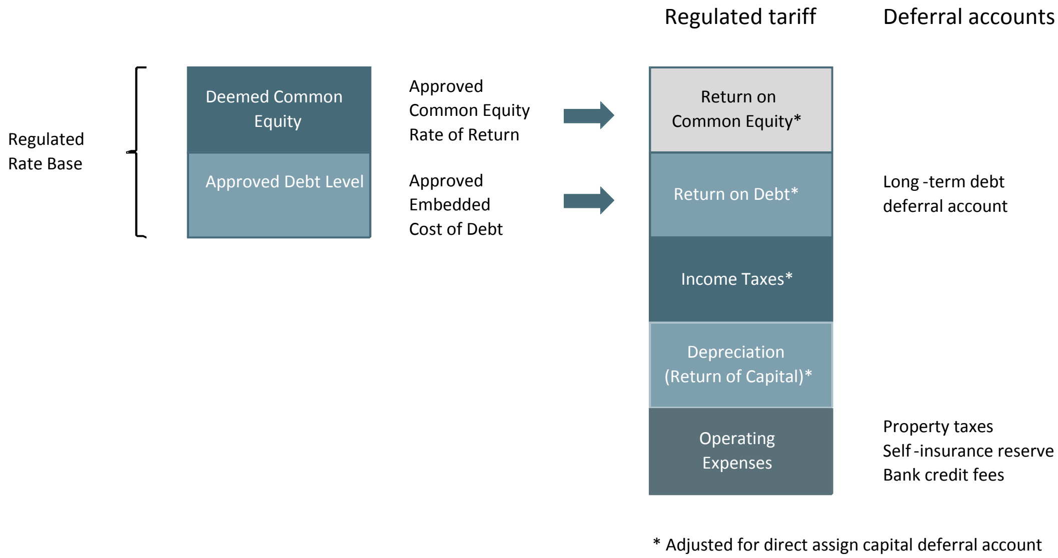
Overview of Our Transmission Tariffs

We are an electric utility regulated by the Alberta Utilities Commission (AUC), pursuant to the *Electric Utilities Act (Alberta) (EUA),* 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.

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.

If our actual costs exceed approved forecast costs (adjusted for deferral accounts, where applicable) for any reason, our financial performance will be adversely affected. Our actual costs could exceed 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. To mitigate such forecast risks, for the mutual benefit of consumers or the utility, the AUC may approve the use of deferral or reserve accounts to adjust transmission tariffs to reflect actual costs after such costs are known. 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 considered by the AUC in arriving at its decision.

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.

General Tariff Application and Transmission Tariffs for 2009 and 2010

An appeal of our 2009-2010 GTA is currently before the Alberta Court of Appeal with respect to the approval of our costs incurred in the voided North/South Project proceeding. The basis for the appeal is that the presence of one AUC member on the panel considering the GTA contravened an AUC policy and gave rise to a reasonable apprehension of bias because that member participated in both the voided North/South decision as well as the GTA decision in which the costs related to the North/South line were approved.

General Tariff Application and Transmission Tariffs for 2011 and 2012

In recent tariff and cost of capital decisions, the AUC stated that it was in the best interests of ratepayers for AltaLink and other transmission facility owners to maintain their current credit ratings. The AUC affirmed its support by approving certain measures to improve the credit metrics of transmission facility owners, including AltaLink, in anticipation of significantly higher capital expenditures which are expected to be financed over several years. The increases in capital expenditures are largely attributable to new asset construction projects that are expected to be directly assigned to transmission facility owners by the AESO. A central theme of our recent general tariff application was the significant increase in our capital expenditures for 2011 and 2012. As outlined in the Major Capital Projects section of this MD&A, we have filed facility applications with the AUC for more than $2 billion of capital expenditures and have been directed by the AESO to prepare facility applications for other projects for which the AUC has approved need applications. On February 21, 2012 we filed our compliance filing to give effect to Decision 2011-453. As noted above, our actual capital expenditures were more than $670 million for 2011 and we anticipate capital expenditures of more than $900 million for 2012, excluding the forecast 2012 WATL project capital expenditures.

A significant portion of our forecast capital expenditures involves projects that will take several years to complete. Under conventional regulatory tariff practices, all costs related to capital projects, including Allowance for Funds Used During Construction (AFUDC) are capitalized until the assets are available for use, at which time we begin receiving tariff revenues. An alternative approach, sometimes used in other regulatory jurisdictions for large scale projects, is to allow AFUDC to be collected in current period regulated tariffs instead of capitalizing AFUDC to the project and receiving it in future periods over the average life of the related assets. This approach, often referred to as "CWIP in Rate Base", provides the utility with additional cash flow to service the debt obligations incurred to finance the projects. This additional cash flow enables the utility to maintain its credit ratings during the construction program to ensure adequate access to capital markets and optimize the utility's cost of capital underlying future tariffs.

In Decision 2011-453, the AUC approved credit metric relief for our 2011 and 2012 transmission tariffs in the form of (i) the continuation of the future income tax method for federal income taxes and (ii) the use of CWIP in Rate Base. The AUC stated that the need to continue such credit metric relief beyond 2012 will be considered as part of our next GTA.

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.

In Decision 2011-474, which is 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 to 37% from 36%. 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, and subsequently applied to the AUC for Review and Variance 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.

	Year ended December 31,		
Deemed capital structure and generic returns approved by the AUC	**2011**	2010	2009
Deemed capital structure			
Approved common equity ratio	**37.00%**	36.00%	36.00%
Approved debt ratio	**63.00%**	64.00%	64.00%
Generic returns			
Approved return on equity	**8.75%**	9.00%	9.00%

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 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.

Electricity Transmission in Alberta

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.

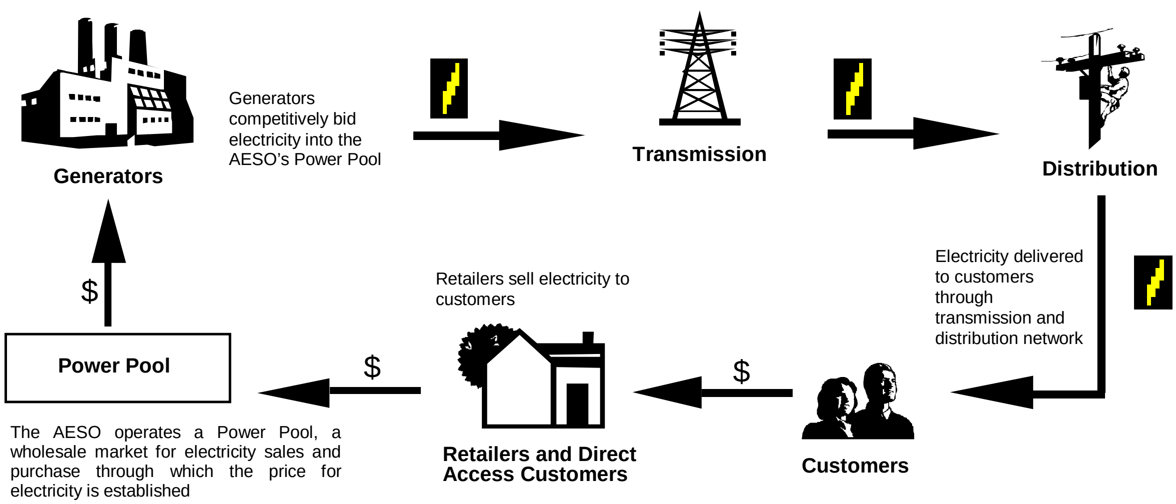
Most of our transmission facilities are situated on lands owned by private landowners, railway companies, industrial customers, and federal and provincial governments, for which we have obtained appropriate land use rights through utility right-of-way agreements, crossing agreements, leases, permits, 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:

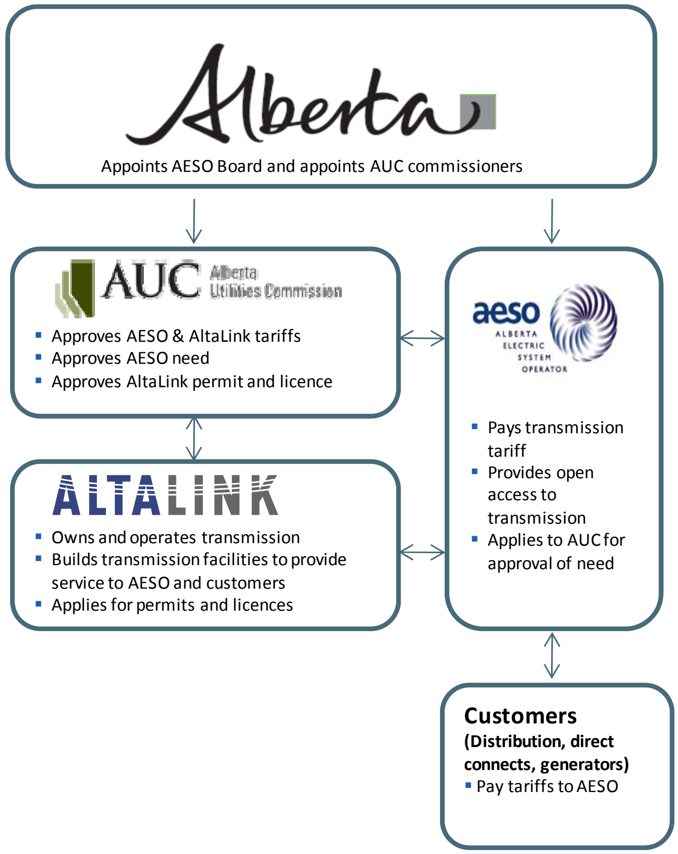
- Generation is the production of electric power. Generators sell wholesale power into the power pool operated by the AESO or through direct contractual arrangements. Most of the power produced in Alberta is generated using coal or natural gas as the fuel source with hydro and wind power adding the majority 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 selling or offering for sale 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 (EUA) and the Public Utilities Act (Alberta). Under the EUA, we must operate and maintain our transmission facilities in a manner that is consistent with the safe, reliable and economic operation of the AIES; 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 Alberta Utilities Commission 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 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 from 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 (ISO) 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 MWhs 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.

Major Capital Projects

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 AIES. To cope with these increased demands, we expect that the AESO will direct us and other transmission facility owners to upgrade and expand the AIES, consistent with:

- The Alberta Government's 2008 *Provincial Energy Strategy*, which included 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*, which, among other things, designates certain transmission facility projects as critical transmission infrastructure, and streamlines the regulatory process for these projects; 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 AIES 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, which is 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 *Electric Statutes Amendment Act, 2009,* does not change any processes related to the ongoing requirement for us to obtain the AUC's approval for Facility Applications, including obtaining approval for the specific routing for transmission facilities and our obligation to consult with affected landowners and other stakeholders prior to proposing specific routes to the AUC for approval. 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 General in Council may make regulations respecting the determination of who may apply for construction or operation of transmission facilities. In the case of critical transmission infrastructure, the Minister may determine eligibility. 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.

System Expansion Plans

The AESO's Long Range Transmission System Plan was recently updated and released in draft in June 2011. The plan identifies 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 a need application has been filed, the AESO's 10-year transmission system plan also identifies additional transmission facilities that could be required depending on how power generation and demand scenarios unfold, and includes a number of regional upgrades.

We expect to develop several of these major transmission projects, as either or both of the AESO's need applications and our Facility Applications have been filed with the AUC. In addition, there are transmission developments designated as critical transmission infrastructure for which we have been or may be directed to file Facility Applications. 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:

Overview

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.	AUC approved in 2009		
Stage I		• Four applications approved including Cassils Bowmanton Whitla projects. • One application planned for 2012.	• Approved elements completed or under construction.
Stage II		• Multiple applications planned.	• Working on facility applications.
Western Alberta Transmission Line Reinforce system backbone between Edmonton and Calgary as HVDC transmission line and converter substations.	CTI designation in 2009	• Filed in March, 2011.	• Awaiting AUC direction.
Heartland Region Transmission Development Double-circuit 500 kV transmission line between the Ellerslie Substation and a new substation in the Gibbons-Redwater area and 240 kV loop from the new substation to service industrial load.	CTI designation in 2009	• Approved on November 1, 2011.	• Under construction.
Edmonton Region Transmission System Upgrade Debottleneck 240 kV system for load growth and decommissioning of coal-fired generation.	AUC approved in 2009	• Five applications filed to date; four approved.	• Approved elements completed or under construction.
East Calgary Transmission Development Reinforce transmission system in east Calgary and interconnect proposed Shepard Energy Centre.	Filed in June, 2011	• Facility applications filed.	• Awaiting decision on need and facility applications.
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.	In progress	• Four applications planned.	• Awaiting need application filing by AESO. • Working on facility applications.
Yellowhead Rebuild and reinforcement of 138 kV system in Yellowhead region.	AUC approved in 2010	• All applications approved.	• Approved elements completed or under construction.
Hanna Reinforcement and enhancements of the transmission system in southeastern Alberta.	AUC approved in 2010	• Three applications filed and hearings completed. • Two applications approved.	• Approved elements under construction.

CTI – Critical Transmission Infrastructure

Southern Alberta Transmission Reinforcement

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 695 MW of 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. We are currently under construction of Stage I. 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 Stage II. In the future, the AESO may also direct us to prepare Facility Applications for Stage III.

As at December 31, 2011, we have incurred capital expenditures totalling $294.0 million on projects comprising the Southern Alberta Transmission Reinforcement. In our most recent general tariff application, we forecast $2.5 billion of capital costs related to the costs of projects comprising Stage I and Stage II.

Stage I

The AUC has approved four facility applications for which the estimated project costs total $808 million. In 2012, we plan to file a facility application for the South Foothills Transmission Project.

During 2011, we completed construction of a 240 kV switching substation at Milo and a phase shifting transformer at Russell. We have started construction of 230 kilometres of 240 kV transmission lines and two substations approved pursuant to the Cassils to Bowmanton and Bowmanton to Whitla facility applications that were approved in June 2011. We plan to complete these facilities in 2014.

Stage II

We plan to file facility applications in 2012 for several Stage II transmission facilities, including the Medicine Hat, Picture Butte to Etzicom Coulee and Etzikom Coulee to Whitla projects. We are continuing with siting and consultation on proposed facilities between Goose Lake and Etzikom Coulee for which we plan to file facility applications in 2013. Pursuant to a recent AUC decision, we are awaiting further direction from the AESO regarding proposed facilities at Fidler.

Western Alberta Transmission Line

Pursuant to the *Electric Statutes Amendment Act, 2009*, the Western Alberta Transmission Line has been identified as Critical Transmission Infrastructure. The existing transmission system to deliver power from the Edmonton to Calgary areas relies primarily on six 240 kV transmission lines in the Edmonton to Red Deer area and seven 240 kV lines between Red Deer and Calgary. The Edmonton to Calgary system has not been upgraded in over 30 years. In its 2009 Long Term Transmission System Plan, the AESO stated that load growth in southern and central Alberta is stressing the existing system such that capacity will fall short of reliability requirements by 2014.

As directed by the AESO, we filed a Facility Application to construct a high voltage direct current transmission line between 1,000 MW converter stations in the Lake Wabamun area west of Edmonton and in the Langdon area east of Calgary. As outlined in the Facility Application, the estimated cost of the project is $1.4 billion. As at December 31, 2011, we have incurred capital costs totalling $74.8 million in connection with this project. The in-service date requested by the AESO for this project is 2014. To ensure the project meets the requested in-service date, we have contracted with a vendor for the supply, installation and commissioning of the HVDC converter stations in order to meet the timely delivery of long lead equipment, advance engineering and to provide greater cost certainty for the project.

In October 2011, the AUC suspended the WATL hearing at the request of the Minister of Energy, pending a government review. The Critical Transmission Review Committee was established to consult with stakeholders to determine if the transmission lines are required within a specified timeframe. On February 13, 2012, the committee issued its report which recommended proceeding with the development of two 500kV HVDC transmission lines, including WATL, as soon as possible. On February 23, 2012, the Government of Alberta announced that it had accepted the conclusions of the Committee, for reinforcement of the North-South transmission system, including the development of the WATL Project.

Heartland Region Transmission Development

The Heartland Region Transmission Development has been identified as critical transmission infrastructure pursuant to the *Electric Statutes Amendment Act, 2009*. In its 2009 Long Term Transmission System Plan, the AESO identified the need for significant system upgrades to meet the expected increase in electricity demand due to residential, commercial and industrial growth in the Heartland Region northeast of Edmonton. The development is also a prerequisite for proposed critical transmission infrastructure projects in northeastern Alberta.

As directed by the AESO, we and EPCOR jointly applied for approval of the 500 kV 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 on November 1, 2011. We have recently started construction activities on the Heartland project and plan to complete these facilities in 2013.

Our share of the estimated costs of the Heartland facilities is $404 million. As at December 31, 2011, our share of costs related to this project totalled $39.6 million, net of costs recoverable from the joint operation partner.

Edmonton Region 240 kV 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 started construction on the elements of the project approved by the AUC and are awaiting the AUC's approvals for one other Application filed in 2010. Assuming timely approval by the AUC in 2012, we expect to complete and energize these facilities in 2013.

We have estimated the total costs of this project to be $101 million. As at December 31, 2011, our total capital expenditures related to this project were $50.2 million.

East Calgary Transmission Development

The East Calgary Transmission Development would connect a proposed ENMAX substation to be built in southeast Calgary and interconnect ENMAX's proposed Shepard Energy Centre. We filed our facility applications in June, 2011 and are preparing for the AUC's hearing on the applications. As of December 31, 2011, we have incurred capital expenditures totalling $4.1 million in connection with these projects. We estimate the costs of these facilities to be approximately $70 million, with an in-service date of 2013. The final transformer replacement is expected to be energized in 2015.

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. The AESO has not yet filed a need application for this project. As at December 31, 2011, we have incurred capital expenditures totalling $14.1 million in connection with this project.

Yellowhead

The AUC has approved the AESO`s need application to upgrade transmission facilities in the Yellowhead region and has approved all facility applications for this project. Approved elements of the project have been completed or are still under construction.

In our most recent general tariff application, we estimated the cost of this project to be $126 million, with in-service dates of 2012. As at December 31, 2011, we have incurred capital expenditures of $75.8 million in connection with this project.

Hanna

The AUC has approved the AESO`s need application to upgrade transmission facilities in the Hanna region. The AUC has approved two of three facility applications for this project. We expect the AUC to issue its decision on the third facility application in the first quarter of 2012. We estimate the cost of this project to be $237 million, with in-service dates in 2012 and 2013. As at December 31, 2011, we have incurred capital expenditures of $36.9 million in connection with this project.

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 and Athabasca regions.

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.

During 2011, we continued to strengthen our environmental management system and were proactive in environmental issues related to our transmission business:

- We hosted the first ever Avian Power Line Interaction Committee (APLIC) workshop in Canada to provide our industry and regulators an opportunity to engage in productive dialogue on avian protection;
- We signed an agreement with a third party to purchase our used wood poles for the purposes of re-use;
- We continued having comprehensive environmental assessments completed by experienced environmental firms to support major project developments;
- We spent approximately $15.8 million (2010-$14.8 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 have dramatically reduced bird and other wildlife outages at our substations throughout the province by 95%.

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 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 polychlorinated biphenyls (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:

- spill response guidelines have been developed and field personnel trained;
- all new transformer installations have secondary oil containment features;
- incidents are tracked and managed through an incident reporting database;
- an SF6 gas inventory process has been implemented, including the ability to store and reuse gas during maintenance activities; and
- routine transformer oil monitoring and PCB analysis.

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 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 2011, 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 tax (EBIT) and earnings before interest, tax, depreciation and amortization (EBITDA) are useful supplemental measures to analyze 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.

Results prior to January 1, 2010 have been accounted for using the Canadian Generally Accepted Accounting Principles that were in effect at that time.

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, 2011. Our financial statements include more detailed information regarding the changes in our property, plant and equipment.

	Increase/(Decrease) ($ Millions)	Explanation
Property, plant and equipment (note 7)	564.9	We had additions of $659.0 million to capital assets and CWIP, partially offset by $83.1 million in depreciation.
Trade and other payables (note 10)	83.0	Higher construction activity and reclassification from non-current to current.
Short-term debt (note 11a)	104.0	We issued commercial paper to finance our capital expenditure program and reclassified $85.0 million of long-term debt due to be repaid in 2012.
Current and non-current deferred revenue (note 12)	59.4	We transferred $72.9 million from third party deposits, received $10.4 million through transmission tariff for salvage costs and recognized $23.9 million as revenue.

	Increase/(Decrease) ($ Millions)	Explanation
Long-term debt (note 11b)	189.0	We issued $275.0 million of medium-term notes to finance our capital expenditure program and reclassified $85.0 million to short-term debt.
Partners' equity (note 19)	199.3	We generated comprehensive income of $85.3 million. We received $145.0 million of equity contributions from AILP, and distributed $31.0 million to AILP.

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, provides us with sufficient liquidity to finance our planned operations and capital projects.

During the year, we increased our bank credit facilities to an aggregate of $900.0 million. The $850.0 million commercial paper backstop facility provides support to our commercial paper program. As at December 31, 2011, $19.0 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, 2011, we had $880.6 million of liquidity remaining under those facilities. Our liquidity requirements are expected to increase over the next few years to accommodate higher capital expenditures and working capital requirements.

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, 2011	December 31, 2010	December 31, 2009
Interest coverage			
EBIT coverage [2, 3]	**2.39X**	2.28X	2.32X
EBITDA coverage [2, 4]	**3.93X**	3.98X	4.21X
FFO coverage [2, 5]	**2.55X**	2.68X	2.67X
FFO/debt [6]	**11.76%**	13.41%	14.11%
Debt/total capitalization [7]	**56.90%**	56.19%	54.34%

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. FFO/debt – Funds from operations for the last twelve months divided by short-term and long-term debt, excluding deferred financing fees, plus outstanding letters of credit.
7. 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, 2011, our working capital deficiency was $245.7 million compared with $90.5 million at December 31, 2010. The working capital deficiency includes commercial paper and subordinated notes scheduled to mature within the next twelve months. Our commercial paper program is backstopped by a bank credit facility and we have issued commercial paper to repay the subordinated notes due in 2012 as outlined in our General Tariff Application.

We expect that we will continue to have a working capital deficiency in the future 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, 2011	December 31, 2010	December 31, 2011	December 31, 2010
(in millions of dollars)				
Cash and cash equivalents, beginning of period	**$ 0.5**	$ –	**$ 12.8**	$ 8.3
Cash flow provided by (used in):				
Operating activities	**18.4**	29.7	**142.0**	120.1
Investing activities	**(186.0)**	(93.3)	**(545.1)**	(401.5)
Financing activities	**182.5**	76.4	**405.7**	285.9
Cash and cash equivalents, end of period	**$ 15.4**	$ 12.8	**$ 15.4**	$ 12.8

Operating Activities

For the quarter ended December 31, 2011 our cash flow from operating activities decreased by $11.3 million compared to the same period in 2010, primarily due to accruing the amount due from our joint project partner for its share of costs related to the Heartland project. Excluding this one-time transaction, our cash flow from operations increased by $23.0 million compared with the same period in 2010, primarily due to higher net income and approval by the AUC of measures to enhance funds from operations.

Our cash flow from operating activities for the year ended December 31, 2011 increased by $21.9 million compared to 2010, primarily for the reasons outlined in the paragraph above.

Investing Activities

For the quarter and year ended December 31, 2011, our cash flow used in investing activities increased by $92.7 million and $143.6 million respectively, primarily due to higher investment in new transmission facilities funded by cash disbursements and accounts payable and accruals.

We incurred most of our 2011 capital expenditures in connection with major capital projects that we discuss in more detail in the Major Projects section.

Financing Activities

For the year ended December 31, 2011, cash flow provided by financing activities increased by $119.8 million compared to 2010. We issued $19.0 million in short-term debt, compared to repaying $48.0 million during 2010. We issued $275.0 million of long-term debt in both 2011 and 2010. AILP contributed $145.0 million (2010 – $89.4 million) of new equity and we distributed $31.0 million to our partners (2010 - $28.0 million).

For the quarter ended December 31, 2011, cash flow provided by financing activities increased by $106.1 million compared to the same period in 2010. We issued $275.0 million of long-term debt compared to $150.0 million for the same period in 2010. We repaid $152.5 million of commercial paper, compared to repaying $125.5 million during the same period in 2010. AILP contributed $70.0 million (2010 – $60.1 million) of new equity and we distributed $7.8 million to our partners (2010 - $7.0 million).

Earnings Coverage

	Year ended December 31, 2011	December 31, 2010	December 31, 2009
Earnings-to-interest coverage on total debt [1,2]	**2.08X**[3]	**1.99X**	**2.28X**

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 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 (excluding 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 long-term debt for the year ended December 31, 2011, was $70.7 million (2010 - $59.2 million; 2009 - $44.1 million, including the pro-forma effect of interest payable on the Series 2011-1 notes issued in November 2011. Our earnings before interest and income tax, for the purposes of calculating this ratio, were approximately $146.8 million (2010 - $118.1 million; 2009 - $100.7 million).

Credit Ratings

	Year ended December 31, 2011	December 31, 2010	December 31, 2009
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 February 15, 2012, DBRS confirmed the above ratings, both with stable trends.
2. On November 2, 2011, 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	**$ 1,331.2**	**$ 104.1**	**$ 325.2**	**$ —**	**$ 901.9**
Operating leases	**40.8**	**4.4**	**8.3**	**6.3**	**21.8**
Total contractual obligations	**$ 1,372.0**	**$ 108.5**	**$ 333.5**	**$ 6.3**	**$ 923.7**

The contractual commitments for the purchase of property, plant and equipment as at December 31, 2011 are $1,062.1 million.

Results of Operations

Details about differences between IFRS and C-GAAP for revenue and the other items included in this section can be found in the financial statements, Note 24 – *Explanation of the transition from Canadian GAAP to IFRS.*

Revenue

		Year ended	
	December 31, 2011	December 31, 2010	December 31, 2009
(in millions of dollars)			
Operations	**$ 343.2**	$ 297.0	$ 242.7
Other	**22.3**	28.4	14.9

		Quarter ended	
	December 31, 2011	December 31, 2010	December 31, 2009
(in millions of dollars)			
Operations	**$ 116.5**	$ 87.5	$ 72.1
Other	**6.0**	8.7	4.2

Revenue from operations:
Revenue from operations includes all revenue earned from our ordinary business activities, i.e. the provision of electricity transmission services. We earn most of our revenue from providing electricity transmission services. Our transmission tariff includes recovery of forecast operating costs, depreciation and amortization expenses, return on rate base and allowance for funds used during construction (AFUDC).

Our revenue from operations increased by $29.0 million for the quarter ended December 31, 2011 compared to the same period in 2010. This was primarily due to additional investments in capital assets and the impacts of recent regulatory decisions, including the approval of the CWIP in rate base method. Our revenues from operations increased by $46.2 million for the year ended December 31, 2011, compared to 2010, primarily due to similar reasons.

In Decision 2011-453 the AUC approved the use of CWIP in rate base method, under which we recover the AFUDC related to capital projects directly assigned by the AESO within the current year's transmission tariff. Previously, for regulatory purposes, we capitalized the AFUDC as part of the cost of the related assets and recovered it over the average lives of the assets.

Other revenue:
Other revenue includes revenue received from third parties, such as other utilities, and contributions received towards the construction of assets.

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. 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.

Total Comprehensive Income

	December 31, 2011	December 31, 2010	December 31, 2009
(in millions of dollars)			
Year ended	**$ 85.3**	$ 66.3	$ 56.5
Quarter ended	**30.3**	15.5	21.7

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 increased investment in electric transmission infrastructure, and the impact of recent regulatory decisions.

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

		December 31, 2011		December 31, 2010		December 31, 2009
(in millions of dollars)						
Year ended	**$**	**241.5**	$	206.8	$	180.1
Quarter ended		**78.7**		56.2		55.5

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. Please refer to "Non-GAAP Financial Measures" for more information about how we calculate EBITDA.

Operating Expenses

		December 31, 2011		December 31, 2010		December 31, 2009
(in millions of dollars)						
Year ended	**$**	**73.8**	$	74.4	$	72.2
Quarter ended		**19.8**		18.6		19.0

Our operating expenses include salaries and wages, contracted manpower, general and administration costs. Our operating expenses for the quarter and year ended December 31, 2011 are comparable to the same periods in 2010, which included additional costs related to cost recovery projects. However, excluding cost recovery projects, our operating expense increased by almost 11% from 2010 due to growth in our transmission system. Expenses incurred for cost recovery projects are recovered through revenue and therefore have no net income impact as discussed under "revenue" above.

Property Taxes, Salvage and Other

		December 31, 2011		December 31, 2010		December 31, 2009
(in millions of dollars)						
Year ended	**$**	**44.6**	$	44.1	$	16.5
Quarter ended		**11.5**		14.1		3.4

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 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, 2011	December 31, 2010	December 31, 2009
(in millions of dollars)			
Year ended	**$ 93.1**	$ 86.9	$ 79.2
Quarter ended	**31.3**	26.1	21.9

We calculate depreciation and amortization on a straight-line basis using various rates, which are approved by the AUC. 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, 2011	December 31, 2010	December 31, 2009
(in millions of dollars)			
Year ended	**$ 62.4**	$ 46.8	$ 44.4
Quarter ended	**24.0**	14.9	11.9

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, 2011 increased by $9.1 million and $15.6 million, respectively, compared to the same periods in 2010 due to additional debt incurred to finance our capital expenditure program. Our total debt at December 31, 2011 was $293.0 million higher than a year earlier.

Selected Financial Information Derived from our Financial Statements

		Year ended	
	December 31, 2011	December 31, 2010	December 31, 2009
Net income per unit ($/unit)	**0.258**	0.202	0.170
Funds generated from operations ($ millions)	**156.5**	139.1	114.4
Distributions per unit ($/unit)	**0.093**	0.084	0.069
Total assets ($ millions)	**3,156.5**	2,486.2	1,999.3
Short and long-term debt ($ millions)	**1,331.1**	1,037.7	810.9

Summary of Quarterly Financial Information

QUARTER ENDED	REVENUE ($MILLIONS)	NET INCOME ($MILLIONS)	UNITS OUTSTANDING (MILLIONS)	NET INCOME PER UNIT ($/UNIT)
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
DECEMBER 31, 2009	76.4	21.7	331.9	0.065
SEPTEMBER 30, 2009	60.6	9.8	331.9	0.030
JUNE 30, 2009	61.4	13.0	331.9	0.039
MARCH 31, 2009	59.3	12.1	331.9	0.036

Risk Management

Our transmission business is subject to a variety of 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 annual 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. In our most recent GTA Decision, the AUC approved the recovery of approximately $7.0 million through our self-insurance reserve for costs related to damaged transmission lines caused by severe storms in early 2010.

The Liability Protection Regulation limits our liability in the course of carrying out our duties, responsibilities and functions under the Electric Utilities Act for 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 Risk

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 has been mitigated because the AUC has approved the use of the CWIP in rate base method in determining our 2011-12 transmission tariffs. While we intend to apply 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 the AUC's decision may adversely impact us and there can be no assurance that we can entirely recover the actual costs of directly assigned capital projects though 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 Risk

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 February 15, 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 November 30, 2010 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 Risk

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 consistently deliver power in a cost-effective manner is subject to the risk of service interruptions from factors that include equipment failure, accidents, severe weather conditions and other acts of nature, and acts of vandalism, sabotage or terrorism. In recent years, the reliability of our transmission assets has also been impacted by increased congestion on our system as generation and load have grown significantly in Alberta, while the approval and construction of required new transmission facilities have been delayed. Power system congestion requires us to operate older infrastructure at higher capacity and reduces our opportunities to temporarily take facilities out of service for maintenance projects.

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.

We may also be subject to penalties for non-compliance with new reliability standards, which are being developed by the AESO for approval and enforcement by the Market Surveillance Administrator. The costs of implementing and complying with these reliability standards, and the AUC's penalties associated with non-compliance, may be substantial and we may not be able to recover these costs through our tariff. Substantial unrecovered costs could 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 remain unchanged in negotiations or mediation, or that the terms of the collective bargaining agreements will be renewed on acceptable terms. If that occurs, 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 be material and 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 generally operates on the premise that transmission services are most efficiently supplied when transmission facility owners provide most of the facilities and services required within their respective geographic service territories. However, recent legislation changes have been made where the assigning of critical transmission projects may be made through competitive tender regardless of historical service area. The AESO has applied to the AUC for approval of its proposed framework for competitive bidding. The AUC has suspended its review of the AESO's application. 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 and AHLP. 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.

In 2002, we executed a ten-year contract under which a subsidiary of SNC-Lavalin Inc. (SNC-ATP) provides engineering, procurement and construction management services for our direct assigned capital projects. The AUC has reviewed and approved the terms and conditions of this contract in Decision 2003-061 and subsequent decisions. We have incurred $419.6 million for construction related services with SNC-Lavalin ATP Inc. during the year ended December 31, 2011 compared to $262.3 million for 2010. On December 31, 2011, our accounts payable and accrued liabilities included $143.9 million owing to SNC-ATP under this agreement, compared to $88.6 million at December 31, 2010.

As at December 31, 2011, we were indebted to AILP for $85.0 million in principal and $1.1 million of accrued interest under our Series 3 Subordinated Bridge Bond, which has since been repaid on January 3, 2012. During 2011 and 2010 we made quarterly interest payments of $1.7 million to AILP at an annual interest rate of 8.0%.

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.

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 – Basis of Preparation, in the Financial Statements

Accounting Changes

Changes in Accounting Policies for 2011

The CICA Accounting Standards Board requires the conversion to IFRS from Canadian GAAP for publicly accountable profit-oriented enterprises for both interim and annual financial statements beginning on or after January 1, 2011.

We have completed the transition to IFRS. This is the first year in which we are issuing financial statements in accordance with IFRS. Our quarterly statements in 2011 were in compliance with the interim reporting requirements found in IAS 34 – *Interim financial reporting*. Our first annual IFRS compliant financial statements are for the year ending December 31, 2011.

See note 24 – *Explanation of transition from C-GAAP to IFRS* in the financial statements showing how we reconciled the differences between our financial statements under C-GAAP and IFRS.

Applying the changes in accounting standards did not have a material impact on our retained earnings. We have not made any significant changes to the way we apply to the regulator for tariff applications, how we receive tariff and how we conduct our operations. Most of the adjustments we made were reclassifications on the Statement of Financial Position and Statement of Comprehensive Income.

We have recognized all revenue from our core operations in one line on the Statement of Comprehensive Income and all revenue from third parties as other revenue.

We have presented expenses in our Statement of Comprehensive Income by nature, classified as follows:

- Operating expenses – included in operating expenses are employee salaries and benefits, contracted labour and general and administration expenses.
- Property taxes, salvage and other – included are property taxes, salvage expenses, annual structure payments, self-insurance recoveries and hearing and credit facility costs. These costs are fully recovered from the AESO on a deferral and reserve account basis.
- Depreciation and amortization – as a capital intensive business, this is a significant expense for us. We have disclosed this item separately as a result.

We have reclassified certain items on the Statement of Financial Position as follows:

- Software and land rights from PP&E to intangible assets;
- Third party contributions from PP&E to deferred revenue; and
- Assets and liabilities arising from regulated activities to financial assets, financial liabilities or deferred revenue.

Future Accounting Changes That May Impact Our Financial Statements

The following new and revised standards have been assessed for their impact on our financial statements:

Effective for the year ending December 31, 2012

IFRS 7 - *Disclosures – Transfers of financial assets* (IFRS 7) has been amended and is effective for financial periods beginning on or after July 1, 2011. The amendments increase the disclosure requirements for transactions involving transfers of financial assets, for example using receivables, investments or equity to settle transactions. These amendments are intended to provide greater transparency around risk exposures of transactions when a financial asset is transferred and the transferor retains some level of continuing exposure in the asset. The amendments also require disclosures where transfers of financial assets are not evenly distributed throughout the period.

These amendments to IFRS 7 will not have an effect on the Partnership's disclosures as it is the Partnership's practice to settle transactions in cash. However, if the Partnership enters into other types of transfers of financial assets in the future, disclosures regarding those transfers may be affected.

IAS 12 - *Income taxes* (IAS 12) has been amended and will be effective for financial periods beginning on or after January 1, 2012. The amendments to IAS 12 are not expected to affect the Partnership's Financial Statements.

Effective for the year ending December 31, 2013

Amendments to IAS 1 – *Presentation of Financial Statements* were issued 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 affect the Partnership's Financial Statements. The amendments are effective for periods beginning on or after July 1, 2012.

IFRS 10 – *Consolidated Financial Statements*, IFRS 11 – *Joint Arrangements*, IFRS 12 – *Disclosure of Interests in Other Entities* & IFRS 13 – *Fair Value Measurement* were issued by the IASB in May 2011. They replace parts of IAS 27 – *Separate Financial Statements* & IAS 28 – *Investments in Associates and Joint Ventures* and relate to the accounting and disclosure for interests in other companies. IFRS 13 gives 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. Mandatory application is for periods beginning on or after January 1, 2013. The Partnership is currently assessing the impact on the financial reporting for AltaLink. The standards can be adopted early only as a group, with the exception of IFRS 13, which can be adopted early on its own. It is not expected that adopting these standards will significantly impact the Partnership's financial statements. The Partnership does not plan to adopt these standards early.

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. The amendments are effective for financial periods beginning on or after January 1, 2013. Implementing these amendments is not expected to result in material changes to the Partnership's financial statements.

Effective after 2013

IFRS 9 - *Financial Instruments: Classification and Measurement* (IFRS 9) was issued by the International Accounting Standards Board (IASB) on November 12, 2009 and will replace IAS 39 – *Financial Instruments: Recognition and Measurement*. IFRS 9 is effective for annual periods beginning on or after January 1, 2015. The partnership is currently evaluating the impact of IFRS 9. It is not expected to have a material effect on the financial statements of the Partnership.

Controls and Procedures

AltaLink is a 'Venture Issuer' for purposes of Canadian securities regulation National Instrument 52-109 Certificate of Disclosure in Issuers' Annual and Interim Filings (NI 52-109) and, as such, is exempt from certain of the requirements relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting as defined by NI 52-109. Accordingly, the Chief Executive Officer and Chief Financial Officer have reviewed the MD&A and the Financial Statements for the year ended December 31, 2011 (the Annual Filings). Based on their knowledge and exercise of reasonable diligence they have concluded that the Annual Filings fairly represent in all material respects the financial condition, financial performance and cash flows of AltaLink and do not contain any material misrepresentations or omissions.

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”, “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 deemed income tax, 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; 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 which are adverse to AltaLink;
- Decisions from the AUC concerning outstanding tariff and other applications which are consistent with past regulatory principles and are obtained in a timely manner;
- Approved rate-of-return and deemed capital structures for our transmission business which 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 our business 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) on 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 our business 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 risk 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 investors that the above list of factors is not exclusive. 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 found under "Risk Factors and Uncertainties" in our annual 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 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 risk; and
- The impact of accounting standards issued by Canadian standard setters.

All forward-looking information is given as of February 23, 2012. 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.

ALTALINK