



# Management's Discussion and Analysis

**AltaLink, L.P.**
Years ended December 31, 2010 and 2009




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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 25, 2011. 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 25, 2011, 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 audited annual financial statements for the years ended December 31, 2010 and 2009 (the Financial Statements) and the notes thereto.*

*We have prepared our Financial Statements for the year ended December 31, 2010 in accordance with Canadian generally accepted accounting principles (GAAP), using the same accounting policies and procedures that we used to prepare our audited annual financial statements for the year ended December 31, 2009. Amounts are stated 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, 2010, respectively.*

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

# Executive Summary

## Highlights

For the year ended December 31, 2010:

- We reduced our workplace injury frequency rate from 1.42 to 0.31 per 200,000 man hours compared to the same period in 2009;
- We completed construction of the South West 240 kV project, enabling a significant increase in transmission capacity for wind power in the region;
- We achieved before tax income of $66.3 million (year ended December 31, 2009 - $56.5 million);
- We invested $477.4 million (year ended December 31, 2009 - $364.5 million) on capital projects to reinforce and expand the transmission system;
- We issued $275.0 million of 30-year senior debt to support our capital construction program; and
- We filed a record number of Facility Applications, the largest of which relates to the Cassils to Bowmanton to Whitla and to the Heartland Region Transmission Development projects.

# 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 while investigating and assessing 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 have numerous core competencies and resources that enable us to achieve our corporate objectives.

### 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 their indirect ownership in AILP, SNC-Lavalin Inc. (SNC-Lavalin) and Macquarie Transmission Alberta Ltd. (Macquarie) provide 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 fulfil 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 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 our customers by facilitating design and execution of our capital projects in a timely and cost-effective manner. In our General Tariff Application (GTA) for 2011 to 2013, we have outlined our plans for a competitive process to contract for engineering, procurement and construction services beyond the expiration of the SNC-Lavalin contract in 2012.

### 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 long-term and short-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 600 skilled and dedicated people and are continuing to increase our workforce to deliver on the major transmission projects planned in Alberta.

Approximately 360 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). During 2010, we renewed our collective bargaining agreements with the IBEW and UUWA until December 31, 2011 and December 31, 2012 respectively. 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. We were the first Canadian utility to implement an Avian Protection Plan to mitigate avian interactions with our facilities. All new transformer installations feature secondary oil spill containment. Where possible, we use existing rights of way for new facilities. We plan to use high voltage direct current technology for our proposed Western Alberta Transmission Line, to reduce land use impacts and line losses.

### Stakeholder Engagement

We actively engage our stakeholders by providing them with timely, easy to understand information about our proposed transmission projects and gather their input in group or individual meetings to identify routes with the lowest 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 is comparable to other transmission facility owners in Canada for reliability, safety and cost effectiveness since our inception.

*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, and continually strive to further reduce the duration of system outages for the benefit of our customers.

The results below have not been adjusted for the major spring storms which caused significant damage in April, 2010. If the spring storms had been excluded, the frequency of outages would be reduced from 1.52 to 1.26 and the duration of outages would be reduced from 1.25 to 0.66.

| | Year ended December 31, | | |
|---|---|---|---|
| | **2010** | 2009 | 2008 |
| **Frequency of outages (SAIFI)** [1] | | | |
| AltaLink | 1.52 | 0.96 | 1.12 |
| CEA [3] | N/A[4] | 1.72 | 1.39 |
| **Duration of outages (SAIDI)** [2] | | | |
| AltaLink | 1.25 | 0.64 | 1.77 |
| CEA [3] | N/A[4] | 0.94 | 1.03 |

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.
4. The CEA results are not yet available for 2010.

*Safety*

The safety of our employees, contractors and the public is one of our core values, with our ultimate goal being an accident-free workplace. During 2010, we achieved our best safety performance since AltaLink acquired the transmission assets in 2002, delivering results that continue to outperform recent industry benchmarks. Our safety management initiatives encompass all aspects of our safety systems. We are committed to continuously improving our safety culture and safety management processes.

| | Year ended December 31, | | |
|---|---|---|---|
| **All Injury Frequency Rate** [1] | **2010** | 2009 | 2008 |
| AltaLink | 0.31 | 1.42 | 0.73 |
| CEA [2] | N/A[3] | 2.19 | 2.88 |

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.
3. The CEA results are not yet available for 2010.

*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. For a more detailed discussion on our financial metrics, refer to Results of Operations in this MD&A.

## 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. Transmission tariffs for 2010 are based on Decision 2010-409, in which the AUC approved a tariff of $287.6 million for 2010 (2009: $279.5 million) to give effect to Decision 2009-151 (our 2009-2010 General Tariff Application) and Decision 2009-216 (Generic Cost of Capital). We receive our approved transmission tariff from the AESO in equal monthly instalments, while deferral accounts are typically settled with the AESO as lump sums after the AUC has issued decisions on those matters.

The table below summarizes our approved transmission tariffs:

| | Year ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | Approved | Approved | Approved |
| Return on equity | $ 43.0 | $ 34.0 | $ 29.9 |
| Return on debt | 50.1 | 36.8 | 39.6 |
| Operating costs | 90.6 | 84.0 | 78.3 |
| Miscellaneous revenue | (7.1) | (7.0) | (6.1) |
| Depreciation and amortization | 92.4 | 77.0 | 77.3 |
| Income taxes | 12.9 | 11.2 | 9.7 |
| Transmission tariff related to continuing operations | 281.9 | 236.0 | 228.7 |
| Genesee to Langdon 500 kV costs, including income taxes | 5.7 | 43.5 | — |
| Approved transmission tariff | $ 287.6 | $ 279.5 | $ 228.7 |

*Growth in Regulated Capital Assets*

We measure growth in our regulated capital assets (both rate base and construction work in progress (CWIP)) as 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, which 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 the return on equity, recovery of deemed income taxes, and depreciation related to our rate base. We capitalize regulated interest costs and return on equity attributed to our construction work in progress. We do not receive cash flow related to revenue from our construction work in progress until the projects are completed and added to our rate base.

| Mid-year rate base and construction work in progress | 2010 | 2009 | 2008 |
|---|---|---|---|
| | Estimate | Actual | Actual |
| *(in millions of dollars)* | | | |
| Mid-year rate base | $ 1,266.5 | $ 1,044.3 | $ 974.2 |
| Mid-year construction work in progress | 288.2 | 224.3 | 107.2 |

## Outlook

*Growth in Regulated Capital Assets*

We have filed Facility Applications with the AUC in respect of several major capital projects, as well as numerous Facility Applications for regional and other smaller projects. In our most recent general tariff application, we have forecast capital expenditures of $985.8 million for 2011, $1,487.2 million for 2012 and $1,995.9 million for 2013. In the general tariff application, we outlined our plans to finance these capital expenditures through a combination of debt and equity consistent with our capital structure. The amount and timing of our actual capital expenditures may vary from the forecast we included in our general tariff application. Please refer to the Major Capital Projects and Risk Management sections in this MD&A for more information on our capital projects and the associated risk factors and uncertainties.

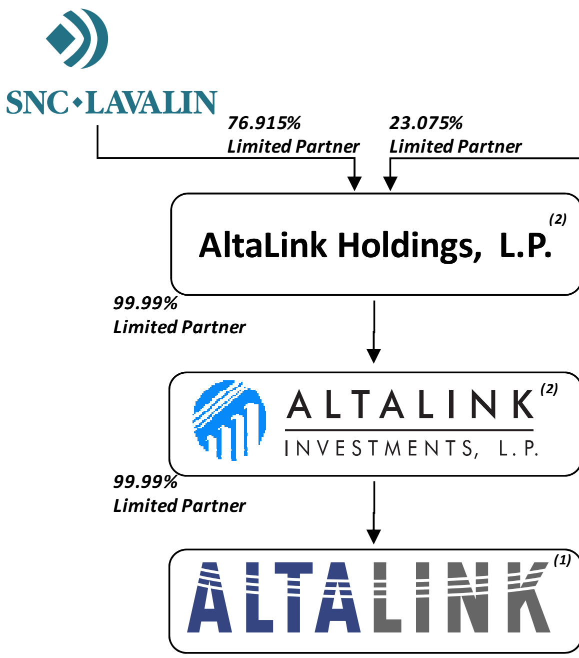
*Transmission Tariff Revenue*

During 2011, the AUC has scheduled hearings to consider our general tariff application for 2011 through 2013, as well as the generic cost of capital for all utilities under its jurisdiction. The outcome of these proceedings may have a material impact on our future net income and capital structure. Please see the Regulatory Tariff Revenues section in this MD&A for more information on these proceedings and the associated risk factors and uncertainties.

## 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.

AILP has one limited partner, AltaLink Holdings, L.P. (AHLP). AltaLink Investments Management Ltd. (AIML) is the general partner of both AILP and AHLP. SNC-Lavalin indirectly owns a 76.92% limited partnership interest in AHLP through subsidiaries and Macquarie owns a 23.08% limited partnership interest in AHLP. On February 11, 2011, SNC-Lavalin announced that it had reached an agreement to acquire the remaining interest in AHLP, pursuant to an offer received from Macquarie. The transaction is subject to customary closing conditions and regulatory approvals, including approval from the AUC. We do not expect that this change in ownership will result in any change to our operations, results, financial condition or the level of support provided by our owners.




(1) AltaLink Management Ltd. is general partner of AltaLink, L.P.

(2) AltaLink Investment Management Ltd. is general partner of AILP and AHLP

## Regulated Tariff Revenues

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.

In Decision 2009-151 the AUC stated that it was in the best interests of ratepayers for AltaLink to maintain its current credit ratings and affirmed its support by approving certain measures to improve our credit metrics in anticipation of several years of significantly higher capital expenditures. In the proceedings leading to those decisions, we outlined anticipated average annual capital expenditures of approximately $650 million over the 2009-2010 period, increasing to over $1 billion annually in 2011 through 2013. The increase in capital expenditures is largely attributable to an increase in new asset construction projects that we anticipate will be directly assigned to us by the AESO.

In Decision 2009-151, the AUC stated that we may apply for additional relief through non-traditional regulatory accounting measures to sustain our cash flow credit metrics at levels required to maintain our current credit ratings. Under traditional regulatory accounting, the interest and return-on-equity related to construction work in progress (referred to as Allowance for Funds Used During Construction (AFUDC)) are capitalized during construction and included in the regulatory rate base when the project is completed and energized. In the United States, the Federal Energy Regulatory Commission has allowed regulated utilities to include AFUDC related to major transmission projects in annual tariffs, a method often referred to as CWIP in Rate Base. The Ontario Energy Board has also stated that it may consider similar measures for major transmission projects within its jurisdiction. In its decision, the AUC stated that CWIP in Rate Base *"is the Commission's preferred method of addressing any remaining credit metric concerns identified by AltaLink in the Application because it directly addresses the fundamental cause of the cash flow problem that is impacting credit metrics."*.

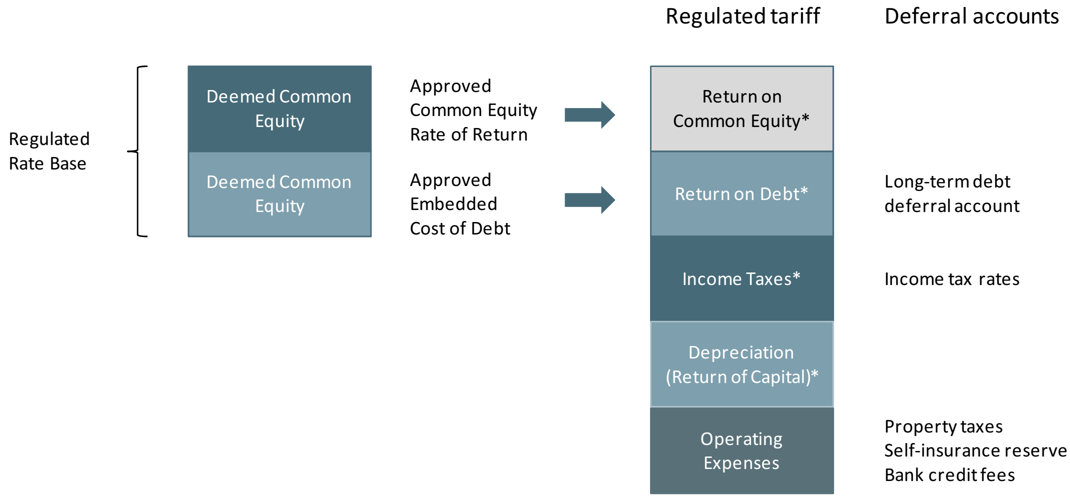
In December 2010, we filed our general tariff application for 2011 to 2013 with the AUC. In that application, we forecast significantly higher capital expenditures during the three year test period and beyond. Consistent with Decision 2009-151 we have asked the AUC to continue the measures approved in that decision and to provide further relief in the form of CWIP in Rate Base during the test period. In addition, we have asked the AUC to approve temporary increases in our common equity to further improve our credit metrics to levels consistent with our current credit ratings.

## Overview of Our Transmission Tariffs

Under the Electric Utilities Act, we must prepare and file applications with the AUC for approval of tariffs to be paid by the AESO for the use of our transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approved 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) receive a fair return on equity we invest in our rate base; (ii) earn an allowance for funds used during construction; and (iii) recover our forecast costs, including operating expenses, depreciation, cost of capital and taxes (including 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.




* Adjusted for direct assign capital deferral account

*Return on Rate Base and Allowance for Funds Used During Construction*

We are entitled to receive a fair return on the capital we invest in our rate base and construction work in progress. 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: an assessment of the business risk of each utility sector and applicant; deemed capital structures previously approved for each applicant; comparable determinations by regulators in other jurisdictions; interest coverage ratio analysis; and bond rating analysis.

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.

In Decision 2009-216, the AUC increased our regulated equity ratio from 33% to 36% and fixed the regulated rate of return on common equity at 9% for 2009 and 2010. The AUC has initiated a proceeding to review the generic cost of capital for all utilities in its jurisdiction for 2011 and future periods. See Regulatory Applications that Affect our Revenue in this MD&A.

Traditionally, the allowance for funds used during construction has been capitalized to the cost of associated capital projects until they are energized and added to the regulated rate base. This method of capitalization allows us to accrue a return on construction work in progress, which is recovered over the average life of property, plant and equipment assets. In our most recent general tariff application, we have applied to the AUC to have the allowance for funds used during construction to be included in our transmission tariffs for 2011 through 2013. Including AFUDC in our tariff allows us to recover the return immediately instead of over the average life of the assets, as reflected in AUC decision 2009-151.

| **Deemed capital structure and generic returns approved by the AUC** | Year ended December 31, **2010** | 2009 | 2008 |
|---|---|---|---|
| **Deemed capital structure** | | | |
| Approved common equity ratio | **36.00%** | 36.00% | 33.00% |
| Approved debt ratio | **64.00%** | 64.00% | 67.00% |
| **Generic returns** | | | |
| Approved return on equity | **9.00%** | 9.00% | 8.75% |
| Approved cost of debt | **5.54%** | 5.58% | 5.78% |

*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 and the costs of removing such facilities at the end of their useful lives. We are entitled to recover the net book value of assets included in our regulated rate base, together with the forecast costs of removing those facilities, 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 that ultimately hold partnership interests in AHLP. Our transmission tariffs include recovery of income taxes that the AUC deems we will incur in connection with our regulated operations. The AUC has directed us to use the future income tax method for calculating deemed federal income taxes and the flow-through method for provincial income taxes.

In Decision 2009-151, the AUC permitted us to *"further delay the implementation of FTT (Flow-Through Tax) to further support the utility's credit metrics"*. In our most recent general tariff application, we have asked the AUC to continue to allow the use of the future income tax method for 2011 through 2013. This would provide us with higher tariffs and cash flow to support our cash flow credit metrics during the forecast construction of major transmission projects for the test period. 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.

## Regulatory Applications that Affect our Revenue

*2009 Generic Cost of Capital*

On November 12, 2009, the AUC issued Decision 2009-216 regarding its 2009 generic cost of capital proceeding. The decision established a common (or generic) regulatory approach to cost of capital matters for electricity and natural gas utilities under the AUC's 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.

Pursuant to Decision 2009-216, the generic rate of return on common equity increased to 9% from the interim rate of 8.75% previously set by the AUC as a placeholder for 2009. The approved generic rate of return on common equity remained in effect for 2009 and 2010. In addition, the decision increased our common equity ratio to 36% from 33%. The approved common equity ratio will remain in effect until changed by the AUC. In Decision 2009-216, the AUC decided not to discontinue its adjustment formula for the generic rate of return on common equity. The adjustment formula, previously approved in Decision 2004-052, resulted in rates of 9.6% for 2004, 9.5% for 2005, 8.93% for 2006, 8.51% for 2007, and 8.75% for 2008. Had the AUC continued the adjustment formula for 2009, the rate of return on common equity would have been set at 8.61%.

*Transmission Tariffs for 2009 and 2010*

In Decision 2010-409, the AUC approved transmission tariffs of $287.6 million for 2010 (2009: $279.5 million) to give effect to its earlier decisions regarding our 2009-10 general tariff application (Decision 2009-151) and its most recent generic cost of capital proceeding (Decision 2009-216). Our actual revenue for 2009 and 2010 reflects estimated adjustments relating to the future settlement of the deferral accounts and reserve accounts approved by the AUC in Decision 2009-151.

In Decision 2009-151, the AUC made directives related to our 2009-2010 general tariff application, including approval of:

- increases in operating expenses, including manpower costs;
- depreciation rates;
- capital expenditures for capital replacement and upgrade programs;
- costs relating to increasing AltaLink's bank credit facilities from $285 million up to $600 million; and
- continuation of deferral accounts for long-term debt interest costs, property taxes and direct assigned capital expenditures.

In Decision 2009-151, the AUC did not approve our request for a management fee on customer contributed projects and indicated that this issue will be addressed in a future process. During 2010, the AUC announced its intention to consider management fees on customer contributed projects within the scope of its 2011 generic cost of capital proceeding.

In the 2009-10 GTA Decision, the AUC demonstrated support for our credit ratings by: (i) directing the continued use of the future income tax method for calculating deemed federal income tax (this provides us with higher tariffs and cash flows to support our cash flow credit metrics during the construction of major transmission projects); (ii) allowing us to recover all costs incurred for the Genesee to Langdon 500kV project; and (iii) stating that, if necessary, we may apply for additional relief to sustain our cash flow credit metrics through non-traditional regulatory accounting measures such as the inclusion of CWIP in Rate Base.

In Decision 2009-151, the AUC directed us to invoice the AESO for $35.0 million of costs related to the voided Genesee to Langdon 500kV project and to recover the balance of these costs through our revenue requirement for 2009 and 2010. The AUC's directive was clear that we should not be harmed financially by the cancellation of the project. Prior to Decision 2009-151, we had accounted for these costs as capital assets included in our regulatory rate base, consistent with the treatment we had proposed in our 2009-2010 general tariff application. When Decision 2009-151 was issued, we reclassified the remaining net book value of $36.7 million from capital assets to regulatory assets. In June 2010, the AUC made its final determination regarding the recovery of these costs, including financing costs and deemed income taxes in respect thereof. We recognized the impact of the AUC`s decision in our results for the quarter ended June 30, 2010.

*Decisions Related to Approval of Deferral Accounts*

Since 2003, the AUC has approved a deferral account to adjust our revenue requirements for cost forecasting risks on capital projects directly assigned to us by the AESO. After reviewing our direct assigned capital project costs for prudency, the AUC adjusts our approved revenue requirement to reflect the difference between the forecast and actual costs of direct assigned capital projects added to our regulated rate base.

On October 19, 2010, we applied to the AUC for approval of our deferral account reconciliations for the year ended December 31, 2009. We expect the AUC to issue its decision on this application in 2011. In Decision 2009-151, the AUC approved deferral and reserve accounts for the years ended December 31, 2006, 2007 and 2008 that require us to adjust certain forecasts made in our general tariff applications to reflect actual costs. Our deferral, reserve and other regulatory accounts are described in more detail in Note 5 of the Financial Statements.

*2011 Generic Cost of Capital*

On December 16, 2010, the AUC announced a generic cost of capital proceeding to examine the capital structure of each utility under its jurisdiction, the rate of return on common equity, and customer contributions in aid of construction. An oral hearing is scheduled to start on May 30, 2011.

The AUC has initiated a process to review the generic cost of capital for all utilities under its jurisdiction, for which a hearing is scheduled to start in May, 2011.

The scope of the generic cost of capital proceeding will include (i) the generic rate of return on common equity (currently 9%); (ii) the capital structure of each utility, including ours; and (iii) compensation to utilities for managing and operating assets contributed by customers.

We and other utilities are currently preparing evidence, including expert witnesses, that is scheduled to be filed with the AUC on March 14, 2011.

Assuming the hearing proceeds as scheduled, we expect the AUC to issue its decision in late 2011. An increase in our rate of return and equity ratio would increase our net income. Conversely, lower rates of return and equity rates would decrease our net income. We currently receive no compensation for managing and operating customer contributed assets therefore any compensation the AUC may award in its decision would increase our net income. The AUC may also allow customers to adopt proposed Rider I, whereby the utility would refund the unamortized customer contribution and include the resulting investments in its rate base.

*General Tariff Application for 2011 to 2013*

We filed our general tariff application for 2011 to 2013 with the AUC in December, 2010. The AUC has scheduled a hearing on our application for May, 2011 and we expect the AUC will issue a decision in late 2011.

A central theme of our general tariff application is the significant increase in our capital expenditures for the forecast period. 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. In our 2011-2013 GTA, we have forecast our capital expenditures to be $985.8 million in 2011, $1,487.2 million in 2012 and $1,995.9 million in 2013.

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 AFUDC, are capitalized until the assets are available for use, at which time we begin receiving tariff revenues. An alternative approach, often used in the United States for large scale projects, is to add AFUDC to regulated tariffs instead of capitalizing AFUDC to the project. 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 is needed to enable 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 addition to the usual components of our transmission tariffs, our 2011-2013 GTA requests that the AUC approve CWIP in Rate Base treatment for all of our direct assigned capital projects during the test period. In Decisions 2009-151 and 2009-216, the AUC:

(i) concluded that it was in the best interests of customer for utilities to maintain credit ratings in the A category
(ii) stated that CWIP in rate base was its preferred approach to obviating the impact of major construction projects on credit ratings.

The following table summarizes the various components of our proposed transmission tariffs for 2011-2013

| | Fiscal year ending December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| *(in millions of dollars)* | Applied For | Applied for | Applied for |
| Return on equity | $ 167.9 | $ 110.5 | $ 72.0 |
| Return on debt | 157.2 | 102.3 | 69.1 |
| Operating costs | 129.1 | 117.1 | 107.3 |
| Miscellaneous revenue | (8.0) | (7.6) | (7.1) |
| Depreciation and amortization | 159.7 | 126.1 | 106.7 |
| Income taxes | 44.5 | 28.6 | 20.4 |
| Revenue requirement | $ 650.4 | $ 476.9 | $ 368.5 |

In forecasting the costs of the transmission business, and estimating the revenue requirements for 2011 through 2013 as outlined in the preceding table, we have relied upon certain assumptions and outlooks for the transmission business detailed in the 2011-2013 GTA. These estimated revenue requirements cover the anticipated costs of operating the transmission business in 2011 through 2013. Certain statements and disclosure contained in this MD&A relate to matters which are not historical facts, including statements and disclosures relating to projected growth in our rate base and capital expenditures outlook and may constitute “Forward-looking information” within the meaning of applicable securities laws. You are cautioned to review the section entitled Major Capital Projects – System Expansion Plans, the discussion under the heading Forward-Looking Information at the end of this MD&A and the section entitled Risk Factors and Uncertainties for further information. These sections provide a more detailed discussion of the material assumptions made by us in developing our capital expenditures outlook and the risk factors related to those assumptions.

In addition to CWIP in Rate Base, we have asked the AUC to temporarily increase the equity ratio in our capital structure from 36% to 38% in 2012 and to 40% in 2013. We have also asked the AUC to permit us to continue recovering federal income taxes using the future income tax method. Pending the outcome of the concurrent GCOC proceeding, our proposed transmission tariff is based on a placeholder rate of return on common equity of 9%.

Our 2011-13 GTA proposes to continue the deferral and reserve accounts approved for our 2009 and 2010 transmission tariffs, with the exception of the deferral account for long-term debt costs.

## Electricity Transmission in Alberta

### Our Transmission Facilities

The Alberta Integrated Electric System is a network or grid of transmission facilities operating at high voltages ranging from 69kV to 500kV. The grid delivers electricity from more than 50 generating units across the province through more than 21,000 km 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, manage and operate approximately 11,800 kilometres of transmission lines and 275 substations 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.

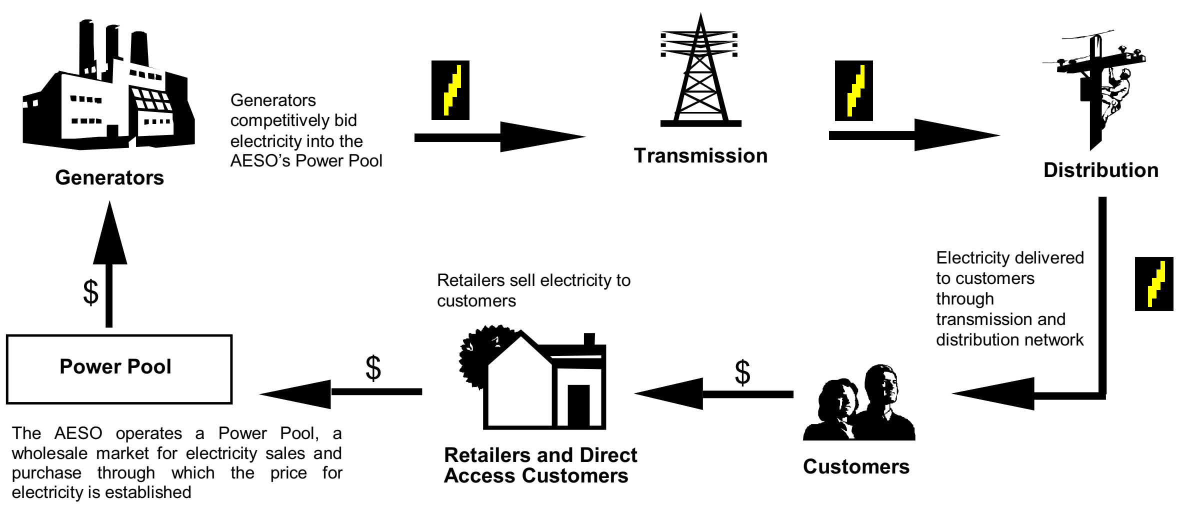
Most of our transmission facilities are situated on lands owned by private landowners, railway companies, industrial customers, and federal and provincial governments, for which we have obtained appropriate land use rights through utility right-of-way agreements, crossing agreements, leases, permits, licences and other agreements. We also own approximately as 5,000 acres of land and 50,000 square feet of office and storage space used in connection with our operations. We lease approximately 171,000 square feet of office and storage space under leases expiring at various times between 2011 to 2026 on customary terms and at market rates.

## Overview of Electricity Industry in Alberta

The electricity industry in Alberta consists of four principal segments:

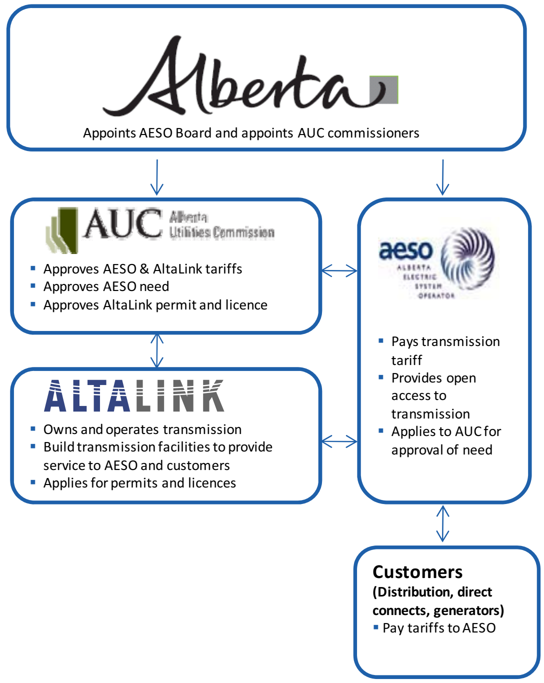
- Generation is the production of electric power. Generators sell wholesale power into the power pool operated by the AESO or through direct contractual arrangements. Most of the power produced in Alberta is generated using coal or natural gas as the fuel source with hydro and wind power adding the majority 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, who 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 (i) 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 the need for most new electricity facilities and permits to build and licences to operate electricity 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, including a ten-year plan issued in June 2009 that identified the potential need for $14.5 billion of transmission development projects over the term of the plan.

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 10-year Transmission System Plan was recently updated in June 2009 and identifies the potential for $14.5 billion in existing and proposed transmission development projects in Alberta in the next 10 years to ensure a reliable supply of electricity. 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 a number or 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.

## Overview

| Project/ Description | Need Application | Facility Application | Status |
|---|---|---|---|
| **South West Project**<br>Double circuit 240 kV transmission line and substations between Pincher Creek and Lethbridge to interconnect wind generation. | AUC approved 2005 | All applications approved. | • All projects completed. |
| **Southern Alberta Transmission Reinforcement**<br>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 2009 | • Multiple applications.<br>• Four filed to date, two approved.<br>• Hearing for two applications scheduled for March 2011.<br>Planning, siting and consultation underway for future applications. | • Approved elements under construction.<br>• Awaiting approval of Facility Applications |
| **Western Alberta Transmission Line**<br>Reinforce system backbone between Edmonton and Calgary as monopole HVDC. | CTI designation in 2009 | • Plan to file in Q1 2011. | • Awaiting approval of Facility Application |
| **Heartland Region Transmission Development**<br>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 | • Filed in September, 2010.<br>• Hearing scheduled for April 2011. | • Awaiting approval of Facility Application |
| **Southeast Alberta Transmission Development**<br>Regional facilities to meet forecast customer load growth, restore the inter-tie to path rating and enable interconnection of proposed wind generation. | AUC approved 2008 | • All applications approved. | • Approved elements completed or under construction |
| **Keephills 3 Generation Interconnection**<br>Interconnect expansion of coal-fired generation facilities at Keephills, west of Edmonton. | AUC approved 2008 | • All applications approved. | • Approved elements completed or under construction |
| **Edmonton Region Transmission System Upgrade**<br>Debottleneck 240 kV system for load growth and decommissioning of coal-fired generation. | AUC approved 2009 | • Two applications approved.<br>• Two applications awaiting approval.<br>• One application planned for 2011. | • Approved elements completed or under construction |
| **East Calgary Transmission Development**<br>Reinforce transmission system in east Calgary and interconnect proposed Shepard Energy Centre | In progress | • Multiple applications required.<br>• Filing planned in 2011. | • Awaiting Need Application filing |
| **Foothills Area Transmission Development**<br>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 | • Multiple applications planned. | • Awaiting Need Application filing |
| **Yellowhead**<br>Rebuild and reinforcement of 138 kV system in Yellowhead region | AUC approved in 2010 | • All applications filed in 2010. | • Awaiting approval of Facility Applications |
| **Hanna**<br>Reinforcement and enhancements of the transmission system in southeastern Alberta | AUC approved in 2010 | • Two applications filed in 2010.<br>• One application planned for Q2, 2011. | • Awaiting approval of Facility Applications |

## South West Project

In November 2010, we successfully completed construction of our largest project to date. This project supports the continued development of more than 800 MW of wind energy projects in southwest Alberta by connecting them to Alberta's main grid. This project included a 90-kilometre 240 kV transmission line between Pincher Creek and Lethbridge, as well as a new substation in the Pincher Creek area, expansion of two existing substations, and other improvements to the existing 138 kV transmission system in southern Alberta. These facilities were energized and added to our rate base in 2010.

## 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 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 1,700 MW. Subsequent development of Stages II and III would further reinforce the system, consistent with the AESO's growth forecast for wind generation facilities in the region.

The AESO has directed us to prepare Facility Applications for those facilities identified in Stage I and Stage II. In the future, the AESO may also direct us to prepare Facility Applications for Stage III. As at December 31, 2010, we have incurred capital expenditures totalling $69.6 million on projects comprising the Southern Alberta Transmission Reinforcement. In our most recent general tariff application, we estimated the costs of the first two stages of the project to be $2.5 billion.

We have filed four Facility Applications related to Stage I, for which the estimated aggregate project costs are $807 million. The two major Facility Applications, Cassils to Bowmanton and Bowmanton to Whitla, are scheduled for AUC hearings in Q1, 2011. These two projects, with an expected in-service date of 2014, include the construction and operation of 240 kilometres of 240 kV transmission lines, as well as substations at those locations. The Milo 240 kV switching substation was approved by the AUC in 2010 and is under construction with an in-service date of Q2 2011. The Russell phase shifting transformer was approved by the AUC in January of 2011, and has an expected in-service date of Q4, 2011.

During 2010, we conducted consultation with landowners and other stakeholders for 240kV transmission lines between the Calgary and Pincher Creek regions. During 2011, we plan to file a Facility Application for these facilities. Assuming these Facility Applications are approved on a timely basis, we expect to complete construction and energize these facilities in 2014. We have also initiated consultation with landowners and other stakeholders on various transmission facilities contemplated under Stage II. We intend to file Applications for these facilities in 2011 and 2012.

## 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 plan to file in Q1 2011 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, 2010, we have incurred capital costs totalling $40.5 million in connection with this project.

The in-service date requested by the AESO for this project is 2014. To ensure the timely delivery of long lead equipment, advance engineering, and to provide greater cost certainty for the project, we have authorized SNC (as our EPCM contractor) to give limited notice to proceed to a vendor for the supply, installation and commissioning of the HVDC converter stations. Under the limited notice to proceed, we will commit to the vendor's engineering and design costs, not to exceed $11 million. The final notice to proceed is contingent upon approval of the Facility Application and receipt of permit and license.

### 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 concluded that the preferred route is superior and is recommended for approval, however, we also provided information in the application respecting a second potential route for the 500 kV line facilities. As this route does not cross EPCOR's service territory, we would be the sole owner and operator of the 500 kV line project along that route. In addition, we independently applied for the Ellerslie substation expansion, the Heartland substation, and the 240 kV line project. The AUC has scheduled a hearing in April 2011 to review the application. Assuming that the AUC approves these applications in 2011, we expect to complete and energize these facilities in 2013.

In our most recent general tariff application, we estimated our share of the costs related to this project to be $383 million. As at December 31, 2010, our share of costs related to this project totalled $40.7 million.

### Southeast Alberta Transmission Development

The AUC has approved the AESO's Need Applications for transmission system development in southeast Alberta. The AUC has approved 10 Facility Applications and we have completed construction of eight of the facilities and expect to complete the remainder in 2011. The estimated total costs of this project are $82 million. As at December 31, 2010, our total capital expenditures related to this project were $75 million.

### Keephills 3 Generation Interconnection Project

In 2008, the AUC approved the AESO's Need Applications for several transmission projects required to interconnect the expansion of the TransAlta/EPCOR 450 MW coal-fired generation facilities at Keephills, west of Edmonton. The AUC has approved all five Facility Applications for the project. We have completed and put into service all elements of the project, including the first phase shifting transformer energized in the Province of Alberta. In our most recent general tariff application, we estimated the cost of this project to be $67.4 million, excluding customer contributions. As of December 31, 2010, our total capital expenditures related to this project were $60.5 million.

### 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 related to two Facility Applications approved by the AUC and are awaiting the AUC's approvals for two other Applications filed in 2010. We plan to file the fifth and final Application in Q1 2011. Assuming approval by the AUC in 2011, we expect to complete and energize these facilities in 2011 and 2012.

In our most recent general tariff application, we estimated the total costs of this project to be $101 million. As at December 31, 2010, our total capital expenditures related to this project were $25.7 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 have completed consultation needed to file our Facility Application during Q1 2011. As of December 31, 2010, we have incurred capital expenditures totalling $2.3 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.

## Foothills Area Transmission Development

The AESO's 2009 Long Term Transmission System Plan identified the need for transmission facilities in south Calgary and surrounding region to reinforce the local transmission system and further interconnect wind energy from southern Alberta into the AIES. 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. In our most recent general tariff application, we estimated the combined costs of the East Calgary and Foothills projects to be $875 million. The AESO has not yet filed a Need Application for this project. As at December 31, 2010, we have incurred capital expenditures totalling $4.5 million in connection with this project.

## Yellowhead

The AUC has approved the AESO`s Need Application to upgrade transmission facilities in the Yellowhead region. We have filed all four Facility Applications with the AUC for this project. In our most recent general tariff application, we have estimated the cost of this project to be $126 million, with in-service dates of 2012. As at December 31, 2010, we have incurred capital expenditures totalling $16.8 million in connection with this project.

## Hanna

The AUC has approved the AESO`s Need Application to upgrade transmission facilities in the Hanna region. We have filed 2 of 3 Facility Applications with the AUC for this project and expect to file the remaining Facility Application in Q2 2011. In our most recent general tariff application, we have estimated the cost of this project to be $237.5 million, with in-service dates of 2012. As at December 31, 2010, we have incurred capital expenditures totalling $5.1 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. In our most recent general tariff application, we forecast capital expenditures totalling $541 million for projects in the Red Deer, Central-East and Athabasca regions. As at December 31, 2010, we have incurred capital expenditures of $3.2 million in connection with these proposed projects.

## Risk Factors and Uncertainties Related to Major Capital Projects

We manage multiple capital projects to support our operations and the growth of our transmission system. Cost estimates for capital projects are impacted by market conditions and evolve as the project scope is refined through landowner consultation, detailed engineering and procurement. Although cost estimates prepared at the Facility Application stage of a project are intended to have an accuracy of plus twenty/minus ten percent (+20%/-10%), the actual costs may exceed estimates.

Our capital projects are subject to risk factors and uncertainties that are normally faced by companies executing large construction projects (see Risk Factors and Uncertainties – *Project Execution Risk*). Some of these risk factors and uncertainties may be more pronounced for our transmission facility projects. We may encounter significant opposition from landowners during regulatory approval processes, which may delay route selection, landowner consultation and compliance (including receiving the required environmental or other permits, approvals and certificates from federal, provincial or municipal agencies). In some jurisdictions, transmission projects have been delayed or cancelled as a result of litigation. Transmission facility projects also face increased risk from the anticipated reduction in availability and increase in costs of materials and services as the transmission industry across North America and around the world continues to experience high levels of development activity.

Project risks can translate into actual project costs being in excess of project cost estimates. Under the regulatory cost-of-service model, we expect to recover the full amount of our actual project costs through tariffs approved by the AUC. We expect that the AUC will continue to utilize a capital deferral account to capture the difference between our forecast costs and the actual costs of direct assigned capital projects. The AUC reviews all project costs which are recorded in the capital deferral account to determine whether the actual costs of projects were prudently incurred. The AESO's Transmission Regulation states that *"the Commission must consider that costs and expenses that are included in a TFO's tariff are prudent unless an interested person satisfies the Commission that those costs or expenses are unreasonable"*. Our most recent reconciliation filing for our capital deferral account was approved by the AUC on June 21, 2010, and included the approval of all capital costs for projects completed during 2007 and 2008. While we expect the AUC to approve the full amount of our direct assigned capital project costs, there are no assurances that the AUC will approve all such costs through its review process (see Risk Management - Risk Factors and Uncertainties – Project Execution Risk).

## 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.

The significant increase in capital projects during 2010 required a corresponding increase in related environment work:

- We recruited seven additional members to the environment team and hired a director to lead our Environment, Health & Safety activities;
- We completed a wood pole preservative soil migration study to enable us to obtain Government of Alberta Reclamation Certificates for salvage and reclamation projects;
- We installed two nesting platforms for ferruginous hawks along the south west 240 kV transmission line;
- We participated in the 2010 ferruginous hawk population inventory;
- We continued having comprehensive environmental assessments completed by experienced environmental firms to support major project developments; and,
- In 2010, we spent approximately $14.8 million (2009-$8.3 million) to manage environmental aspects of our business, including environmental assessments for new transmission facilities.

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.

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.

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.

*Chemical & Spill Management*

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.

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

- incidents are tracked and managed through an incident reporting database;
- spill response guidelines have been developed and field personnel trained;
- substations located in high environmental risk locations (e.g. near open water) have 110% secondary containment features; and
- an SF6 gas inventory process has been implemented, including the ability to store and reuse gas during maintenance activities.

*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, the use of substandard poles, or accidental spills during re-treating operations. 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. 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, aluminum and copper wire, general scrap metal, and battery recycling. General waste and construction waste are delivered to municipal landfill sites through waste service companies.

Even though we replaced PCBs in our main power transformers in the mid-1990s with transformer insulating oil that is free of PCBs, some smaller, sealed auxiliary electrical equipment and components manufactured before production of PCBs stopped in 1977 may contain PCBs. The PCB molecule is extremely stable, which makes it an ideal non-reactive insulating compound but also allows PCBs to persist in the natural environment for a very long time. 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. We believe that we are in compliance with current regulations regarding the use of PCBs.

*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 2010, 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

The health and safety of our employees and contractors is one of our core values. Through a concerted effort to improve our safety performance, we achieved our best safety performance statistics during 2010 and continue to surpass our peers in safety performance.

*Culture*

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. During 2010, we launched an orientation training program for new employees and implemented standards for safe driving, substation safety certification, and guarantee of isolation and switching certification. We are currently progressing on our quality management program for safety codes compliance as well as other initiatives related to office safety, isolated lines and equipment, incident investigations, inspections, work site observations, and switching training

We have implemented incident review meetings with third party service providers to assess their commitment to safety, to challenge them to improve safety performance and safety culture within their organizations, and to seek their commitment to develop continuous improvement action plans.

*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. The key deliverables under our quality management plan include:

- Maintaining a safety codes quality management plan reviewed and approved by Municipal Affairs;
- Annual reviews of the safety codes quality management plan;
- Annual audits of newly energized facilities.

We are committed to building and maintaining facilities that meet or exceed codes by integrating these requirements within our operations and monitoring for compliance. Although the results of our most recent audit confirmed that our facilities meet or exceed safety code requirements, the audit identified gaps in our administrative processes which we intend to remedy through our safety codes initiative. Alberta Municipal Affairs reviewed our quality management plan in 2010 and made five minor recommendations that are also being addressed through our safety codes initiative.

## Non-GAAP Financial Measures

We use certain financial metrics that are not defined under Canadian generally accepted accounting principles. 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.

## Financial Position

The following table discusses significant changes, over $10.0 million, in our balance sheet during the year ended December 31, 2010. Our financial statements include more detailed information regarding the changes in our property, plant and equipment.

| | Increase/(Decrease) ($ Millions) | Explanation |
|---|---|---|
| Property, plant and equipment | $378.6 | During the year we had $468.2 million in net additions for property, plant and equipment, partially offset by $89.6 million in depreciation expense. During the year, we spent $477.4 million in construction expenditures for directly assigned transmission projects and capital replacement and upgrades on our existing facilities. |
| Customer deposits and customer deposits liability | (13.9) | During the year, our customer deposits decreased, mainly due to use of funds for customer contributed projects. |
| Accounts payable and other | 12.4 | Our accounts payable and accrued liabilities fluctuate with capital construction activity levels and the timing of payments to our major suppliers. |
| Regulatory liabilities, long-term | (19.9) | During the year, we settled various deferral accounts with the AESO to reflect Decision 2010-409. We have reclassified long-term regulatory liabilities into short-term based on expected settlement periods. Regulatory liabilities, long-term have also decreased due to the impact of asset retirement obligation amortization and accretion included in our reserve for salvage costs. |
| Asset Retirement Obligations | 53.0 | The increase of $48.6 million relates to the combined impacts of higher inflation rates and lower discount rates, and to new additions to property, plant and equipment. |
| Long-term debt | 225.7 | We issued $125.0 million and $150.0 million of medium-term notes in the first and fourth quarter, respectively. We used these funds to pay down our bank credit facilities of $48.0 million and to finance our capital expenditure program |

*Change in Property, Plant and Equipment*

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| Opening balance, beginning of year | **$ 1,688.0** | $ 1,223.6 | $1,151.6 |
| Net additions | **468.2** | 462.9 | 140.6 |
| Depreciation and other | **(89.6)** | (70.2) | (68.6) |
| Reclassification of reserve for salvage costs | — | 108.4 | — |
| Reclassification of voided 500 kV costs | — | (36.7) | — |
| Closing balance | **$ 2,066.6** | $ 1,688.0 | $ 1,223.6 |

## Liquidity and Capital Resources

### Liquidity

We generally issue commercial paper to finance our day-to-day cash requirements. We believe that our $550.0 million commercial paper backstop facility and our $50.0 million revolving line of credit provide us with sufficient liquidity to finance our planned operations and capital projects for 2011. As at December 31, 2010, we had no borrowings under our revolving line of credit and had no commercial paper outstanding under our commercial paper program, leaving us with $600.0 million of available liquidity under our bank credit facilities.

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. None of our long-term debt instruments are scheduled to mature until 2012. 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 have strict short-term investment policies and have never invested in asset-backed commercial paper. 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, | | |
|---|---|---|---|
| | **2010** | 2009 | 2008 |
| Interest coverage: | | | |
| EBIT coverage [2, 3] | **2.28X** | 2.32X | 1.96X |
| EBITDA coverage [2, 4] | **4.04X** | 4.21X | 3.75X |
| FFO coverage [2, 5] | **2.62X** | 2.67X | 2.67X |
| FFO/debt [6] | **13.12%** | 14.11% | 13.74% |
| Debt/total capitalization [7] | **56.19%** | 54.34% | 62.11% |

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 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 maximum limit of 75%.

*Working Capital*

At December 31, 2010, our working capital deficiency was $82.7 million compared with $91.6 million at December 31, 2009. The decrease is primarily due to the net impact of the increase in current assets outweighing the increase in current liabilities. 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, by committed bank credit facilities. We expect this deficiency to continue in the future due to our system expansion plans

## Cash Flows

| | Year ended December 31, | |
|---|---|---|
| | 2010 | 2009 |
| *(in millions of dollars)* | | |
| Cash and cash equivalents, beginning of year | **$ 8.3** | $ — |
| Cash flow provided by (used in) | | |
| Operating activities | **120.5** | 124.1 |
| Investing activities | **(401.9)** | (218.3) |
| Financing activities | **285.9** | 102.5 |
| Cash and cash equivalents, end of period | **$ 12.8** | $ 8.3 |

*Operating Activities*

For the year ended December 31, 2010, cash flow provided by operating activities was comparable to the prior year. The increases in net income and depreciation were offset by the increases in allowance for funds used during construction, asset retirement obligations settled and non-cash working capital. All increases result from our capital growth during 2010.

*Investing Activities*

For the year ended December 31, 2010, our investing activities included capital expenditures of $477.4 million compared to $364.5 million invested during 2009. Most of our 2010 capital expenditures related to the South West Project, the Western Alberta Transmission Line project, the Keephills 3 Generation Interconnection project, the Southern Alberta Transmission Reinforcement project, the Heartland Region Transmission Development project, other regional projects, and maintenance capital expenditures.

*Financing Activities*

For the year ended December 31, 2010, cash flow provided by financing activities increased by $183.4 million, compared to 2009, primarily due to:

- We issued $125.0 million and $150.0 million of medium-term notes, as compared to the $100.0 million issued in 2009;
- We fully repaid our bank credit facilities of $48.0 million as compared to 2009, in which we repaid $117.0 million; and
- We received $89.4 million in equity contributions from and distributed $28.0 million to AILP as compared to 2009, in which we received $140.5 million in equity contributions form and distributed $22.8 million to AILP.

## Earnings Coverage

| | Year ended December 31, | | |
|---|---|---|---|
| | **2010** | 2009 | 2008 |
| Earnings-to-interest coverage on total debt [1,2] | **1.99X**[3] | 2.28X[4] | 1.95X[5] |

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. Annual interest requirement on long-term debt was $59.2 million, including the pro-forma effect of interest payable on the Series 2010-1 notes issued in March 2010 and the Series 2010-2 notes issued in November 2010. Our earnings before interest and income tax, for the purposes of calculating this ratio, were approximately $118.1 million.
4. Annual interest requirements on long-term debt was $44.1 million, including the pro-forma effect of interest payable on Series 2008-1 notes issued in May 2009. Our earnings before interest and income tax, for the purposes of calculating this ratio, were approximately $100.7 million.

5. Annual interest requirements on long-term debt was $42.7 million, including the pro-forma effect of interest payable on Series 2008-1 notes issued in May 2008. Our earnings before interest and income tax, for the purposes of calculating this ratio, were approximately $83.4 million.

### Credit Ratings

| | Year ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| 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 9, 2011, DBRS confirmed the above ratings, both with Stable trends.
2. On November 30, 2010, Standard & Poor's confirmed the above rating with a Stable trend.

## Commitments and Contingencies

### Contractual Obligations

| | Total | Payments due by periods: Less than 1 year | 1-3 years | 4-5 years | After 5 years |
|---|---|---|---|---|---|
| *(in millions of dollars)* | | | | | |
| Long-term debt | **$ 1,037.7** | **$ 0.4** | **$ 410.3** | **$ -** | **$ 627.0** |
| Operating leases | **40.2** | **3.6** | **6.9** | **6.2** | **23.5** |
| Total contractual obligations | **$ 1,077.9** | **$ 4.0** | **$ 417.2** | **$ 6.2** | **$ 650.5** |

### 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.

We were served with an action on June 5, 2009 alleging that the plaintiff and we had concluded a binding agreement to sell certain lands in Calgary, Alberta to the plaintiff. At this time, in the opinion of management, this matter is not reasonably expected to result in a material adverse effect on our financial position or results of operations.

## Results of Operations

*Revenue*

| | For the year ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| Transmission tariff | **$ 276.0** | $ 236.1 | $ 222.2 |
| Miscellaneous revenue | **19.6** | 14.9 | 8.7 |
| AFUDC equity | **9.6** | 6.6 | 2.5 |

| | For the three months ended December 31, 2010 | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| Transmission tariff | **$ 75.3** | $ 70.0 | $ 58.8 |
| Miscellaneous revenue | **5.0** | 4.2 | 1.8 |
| AFUDC equity | **0.5** | 2.1 | (1.0) |

Our transmission tariff increased by $39.9 million for the year ended December 31, 2010, as compared to 2009, primarily due to additional investments made in our capital assets and the impacts of recent regulatory decisions. The GCOC decision, received in November 2009, increased our rate of return on common equity from 8.75% to 9.00% and our regulated equity ratio from 33% to 36%. These increases were retroactive to January 1, 2009. In August 2010, the AUC approved our compliance filing to give effect to its earlier decisions on our 2009/10 GTA and the 2009 GCOC proceeding. . Our transmission tariff for 2009 increased compared to 2008 primarily due to the same reasons.

Our tariff revenues for the three months ended December 31 increased year over year for the three comparative years for similar reasons. Our 2009 and 2010 transmission tariff includes $43.5 million and $5.7 million, respectively, to recover costs related to the 500 kV project, including related financing costs and deemed income taxes.

Our miscellaneous revenue increased by $4.7 million for the year ended December 31, 2010 as compared to 2009. During 2010 and 2009, we provided $7.2 million and $3.8 million of capital construction services to another utility on a cost recovery basis. The related costs are included in our operating expenses for the corresponding periods. Miscellaneous revenue is comparable for the three months ended December 31, 2009 and 2010. For the three months ended December 31, 2009 miscellaneous revenue includes $2.4 million for capital construction services, compared with nil for the same period in 2008.

We earn an increasing proportion of our revenues through the equity portion of the allowance for equity funds used during construction (AFUDC), which we capitalize to construction work in progress. Due to the increase in our construction activity, our revenue from AFUDC equity increased by $3.0 million for the year ended December 31, 2010, compared to 2009. 2009 and 2008 AFUDC varied due to the timing of construction expenditures.

*Net Income*

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| For the year ended December 31 | **$ 66.3** | $ 56.5 | $ 40.7 |
| For the three months ended December 31 | **$ 15.5** | $ 21.7 | $ 8.5 |

Our net income for the year ended December 31, 2010 increased by $9.8 million compared to 2009 primarily due to additional capital investments and recovery of 500 kV project costs. 2009 increased compared to 2008 due to higher capital investment and the impact of the GCOC decision.

Our net income for the three months ended December 31, 2010 compared to the same period in 2009 decreased by $6.2 million as the three months ended December 31, 2009 included the retroactive impact of the GCOC decision for return on equity and deemed common equity ratio, which was issued during the quarter. The three months ended December 31, 2009 increased compared to the three months ended December 31, 2008 due to higher capital investment and the impact of the GCOC decision.

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

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| For the year ended December 31 | **$ 209.5** | $ 180.1 | $ 159.4 |
| For the three months ended December 31 | **$ 56.5** | $ 55.5 | $ 40.7 |

Our EBITDA for the three months and year ended December 31, 2010 increased compared to the same periods in 2009 while our EBITDA for the three months and year ended December 31, 2009 increased compared to the same periods in 2008. 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 Measure" for more information about how we calculate EBITDA.

*Operating Expenses, Including Property Taxes*

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| For the year ended December 31 | **$ 106.6** | $ 88.6 | $ 78.1 |
| For the three months ended December 31 | **$ 25.0** | $ 22.4 | $ 18.1 |

Our operating expenses include salaries and wages, contracted manpower, general and administration costs, property taxes, and insurance. Our operating expenses for the three months and year ended December 31, 2010 are higher than in 2009, primarily due to inflation and system growth related to recently completed capital projects. As discussed above, operating expenses for 2010 and 2009 also included costs related to capital construction services included in our miscellaneous services. In addition, we incurred approximately $7.0 million of transmission line repair costs as a result of damage caused by snow storms in Southern Alberta earlier in 2010. We charged these costs to operating expenses and recognized offsetting revenue to recover these costs through our self-insurance reserve, which is funded through transmission tariffs.

*Depreciation and Accretion*

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| For the year ended December 31 | **$ 89.6** | $ 79.2 | $ 74.5 |
| For the three months ended December 31 | **$ 26.4** | $ 22.0 | $ 20.9 |

We calculate depreciation on a straight-line basis using various rates ranging from 1.73% to 20.00% which are approved by the AUC. Depreciation for the three months and year ended December 31, 2010 increased by $4.4 million and $10.4 million, respectively, compared to the same periods in 2009, primarily due to capital projects that have since been completed and added to our regulatory rate base. The expense for the year and three month period ended 2009 had increased over 2008 for similar reasons.

*Interest and Amortization of Deferred Financing Fees*

| | **2010** | 2009 | 2008 |
|---|---|---|---|
| *(in millions of dollars)* | | | |
| For the year ended December 31 | **$ 53.6** | $ 44.4 | $ 44.2 |
| For the three months ended December 31 | **$ 14.6** | $ 11.9 | $ 11.3 |

Our interest expense for the three months and year ended December 31, 2010 increased by $2.7 million and $9.2 million, respectively, compared to the same periods in 2009. These changes are due to additional debt incurred to finance our capital expenditures. Our total debt at December 31, 2010 was $225.7 million higher than a year earlier.

*Selected Annual Financial Information Derived from our Financial Statements*

| | Year ended December 31, | | |
|---|---|---|---|
| | **2010** | **2009** | **2008** |
| Net income per unit ($ per unit) | **0.200** | 0.170 | 0.123 |
| Funds generated from operations ($ millions) | **136.2** | 114.4 | 113.4 |
| Distributions per unit ($ per unit) | **0.084** | 0.069 | 0.066 |
| Total assets | **2,377.3** | 1,999.3 | 1,511.0 |
| Long-term debt, excluding current portion [1] | **1,037.3** | 810.5 | 825.2 |

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

*Summary of Quarterly Financial Information*

| Quarter ended | Revenue ($millions) | Net income ($millions) | Units outstanding (millions) | Net Income per unit ($/unit) |
|---|---|---|---|---|
| December 31, 2010 | 80.7 | 15.5 | 331.9 | 0.047 |
| September 30, 2010 | 78.4 | 13.4 | 331.9 | 0.041 |
| June 30, 2010 | 77.8 | 20.3 | 331.9 | 0.061 |
| March 31, 2010 | 68.3 | 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 |
| December 31, 2008 | 59.6 | 8.5 | 331.9 | 0.026 |
| September 30, 2008 | 57.6 | 11.0 | 331.9 | 0.033 |
| June 30, 2008 | 58.5 | 9.6 | 331.9 | 0.029 |
| March 31, 2008 | 57.6 | 11.6 | 331.9 | 0.035 |

## 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 an unacceptable level of earnings. 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. Our most recent general tariff application included an application for the recovery of approximately $7.0 million in costs related to damaged transmission lines caused by severe storms in early 2010 (see Risk Factors and Uncertainties – Regulated Operations).

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

## Risk Factors and Uncertainties

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

We describe our principal risks and uncertainties below.

*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 revenues relating to a project. Delays in receiving expected revenue on 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.

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. 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, detailed engineering and procurement. 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, 2011 ratings report, DBRS stated that its "A" rating of our securities incorporates their assumption that the AUC would, if required, provide us with regulatory support to prevent our credit metrics from declining below acceptable levels throughout the capital expenditure program. 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. On December 22, 2010 we filed our 2011-13 GTA where amount other things, we requested non-traditional regulatory capital accounting during the test period that would provide cash earnings before projects are completed and added to our rate base. As explained above, this approach is based on the need to alleviate credit metric pressures arising from our projected forecast capital expenditures in order to maintain our credit ratings.

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 UUWA or the IBEW. The IBEW collective agreement is effective from January 1, 2010 to December 31, 2011. The UUWA collective agreement is effective from January 1, 2010 to December 31, 2012. 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 good relationships are not maintained, 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 if labour costs rise significantly.

*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 fire fighting 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 will be made through competitive tender regardless of historical service area. 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 $72.6 million and $262.7 million for construction related services with SNC-ATP during the three months and year ended December 31, 2010, respectively, compared to $92.2 million and $200.1 million for the same periods in 2009. On December 31, 2010, our accounts payable and accrued liabilities included $88.6 million owing to SNC-ATP under this agreement, compared to $83.0 million at December 31, 2009.

As at December 31, 2010, 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 is due on October 1, 2012. We make quarterly interest payments of $1.7 million to AILP at an annual interest rate of 8.0%.

## 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.

## 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 following are the more significant estimates that have an impact on our financial condition and the results of our operations:

- key economic assumptions used to determine the estimated cash flows used to assess any potential impairment of long-lived assets;
- the allowance for doubtful accounts;
- the allowance for obsolescence of materials and supplies;
- the estimated useful lives of assets;
- estimates of future costs to dismantle physical assets;
- the recovery of costs associated with direct assigned projects;
- the valuation of intangible assets with indefinite lives, such as goodwill;
- the accruals for accrued liabilities, payroll and other employee-related liabilities;
- certain actuarial and economic assumptions used in determining defined benefit pension costs, accrued pension benefit obligations and pension plan assets; and
- The recovery and settlement of regulated assets and liabilities, including the related transmission tariff revenue impact arising from deferral and reserve accounts, interim tariffs and other matters awaiting regulatory decisions.

*Goodwill*

Goodwill represents the excess of the amount paid over the fair value of the net assets or operations acquired. Goodwill is carried at initial cost less any write-down for impairment. Goodwill impairment occurs when the carrying value of the reporting unit exceeds its fair value. If that happens, we recognize an impairment loss. In the last quarter of each fiscal year, and as economic events dictate, we review the valuation of the goodwill, taking into consideration any events or circumstances which might have impaired the fair value.

We performed a goodwill impairment test as at December 2010. We examined the business and regulatory environment, the ownership structure, financing activities, credit ratings and interest rates. The current economic conditions were considered while doing this analysis. Although the economic conditions may cause some transmission projects to be delayed somewhat, the infrastructure needs of the province must be addressed to ensure the reliability of the system. We also performed a discounted cash flow and net fair value analysis, which compared favourably to the carrying amount of goodwill. We concluded that the carrying value of the goodwill has not been impaired since the last goodwill impairment test in December 2009.

*Revenue Recognition*

Revenues from rate-regulated operations are recognized on the accrual basis in accordance with rates and policies set by the regulator. They include an estimate of services provided but not yet billed. Any revenue that has been received but not yet earned is classified as other liabilities in the financial statements.

*Asset Retirement Obligations*

Asset retirement obligations have been considered for both the retirement of an entire transmission line, or to parts of the larger system. Forecasted future dismantling costs are recognized in the latter circumstance when a component is retired prior to the retirement of the entire transmission line.

We recognize the fair value of forecasted future dismantling costs associated with the retirement of tangible long-lived assets, and record a corresponding increase to the carrying amount of the related assets. This corresponding increase is amortized in a systematic manner over the useful lives of the assets. The discounted present value of the future dismantling costs accretes over time for changes in the present value.

Under current Canadian GAAP, we recognize liabilities for future dismantling costs related to both the interim retirement and the final retirement of transmission facilities. Interim retirements occur when specific transmission assets (such as utility poles and transformers) reach the end of their useful physical lives and are replaced with similar assets as part of our ongoing capital maintenance programs. In most instances, we install replacement assets in the same right-of-way from which we remove the retired assets. Therefore, although we remove the retired assets, we do not conduct final salvage and restoration until all transmission facilities are permanently retired from the site. Most of our transmission facilities are situated on rights-of-way for which we have obtained perpetual easements or other rights. We are not permitted to permanently remove transmission facilities without consent of the AESO and regulatory approval from the AUC. Accordingly, we base our estimates as to the timing of interim retirements for specific assets on independent depreciation studies; however, the timing of final retirement and removal of transmission facilities is indeterminate.

Under current Canadian GAAP, we elected to recognize forecasted future dismantling costs related to interim retirements of transmission lines, but not of electric substations and telecom equipment. Many transmission companies in Canada have elected not to recognize such obligations under current Canadian GAAP. We estimated our future dismantling costs for interim retirements to be $239.3 million as at December 31, 2010 (December 31, 2009 - $186.3 million). We disclose that we have a final salvage and restoration obligation, but we do not disclose the amount, because a reliable estimate cannot be made as it is not possible to calculate a future date when all transmission facilities will be permanently retired. This is consistent with the accounting policies of most other transmission companies in Canada.

*Employee Future Benefits*

All accrued obligations for employee benefit plans and post-retirement benefits are determined using the projected benefit method. In valuing post-retirement benefits as well as cost of pension benefits, we use best estimate assumptions, except for the discount rate, where we use the long-term market rate of high quality debt instruments at the measurement date. Current service costs are expensed in the period. In accordance with GAAP, cumulative net unamortized actuarial gains and losses in excess of 10% of the greater of the benefit obligation, or fair value of plan assets are amortized over the expected average remaining service period of active employees receiving benefits under the plan. For valuing pension assets, we use market values. When the recognition of a transfer of employees and employee related benefits results in both a curtailment and a settlement of obligations the curtailment is accounted for prior to the settlement. Under regulatory accounting principles the expense ultimately recognized in these financial statements is that which is recognized for ratemaking purposes. Although the current market downturn has significantly affected the fair value of the defined benefit plan assets, changes are not material as there are only eleven members in the plan.

# Accounting Changes

## Changes in Accounting Policies for 2010

There were no changes impacting the financial statements as at and for the year ended December 31, 2010.

## Future Accounting Changes That May Impact Our Financial Statements

*International Financial Reporting Standards (IFRS)*

*Transition to IFRS in Canada*
Our first annual IFRS financial statements will be for the year ending December 31, 2011.

Staff Notice 52-320 of the Canadian Securities Administrators requires us to discuss in our interim and annual MD&A the elements, timing and status of our IFRS conversion plan. We refer you to detailed information in this regard that we have previously provided within our MD&A's since the first quarter of 2008 as well as the following update:

Our IFRS conversion project consists of four phases:

- Phase 1 – Project initiation and initial assessment
- Phase 2 – Detailed assessment
- Phase 3 – Design
- Phase 4 – Execution

We have completed the first three phases and are currently finalising the last phase of the project. The Execution phase consists of executing the changes to the information systems and business processes, final approval of our IFRS accounting policies, developing final IFRS accounting policies and procedures and associated documentation, developing revised internal controls and disclosure controls as a result of implementing IFRS, embedding IFRS into business processes and the transfer of knowledge and training of the appropriate individuals. In addition, this last phase will result in an IFRS compliant January 1, 2010 opening IFRS Statement of Financial Position and IFRS compliant financial statements for all periods ending in 2011 with comparative IFRS figures for 2010.

Staff Notice 52-320 issued by the Canadian Securities Administrators (CSA) requires that we estimate the expected effects of the transition to IFRS on our financial statements. IFRS currently does not provide specific guidance regarding accounting for rate-regulated activities. In the absence of a specific standard, we have used the underlying principles within the standards of IFRS to determine the recognition, measurement, presentation and disclosure of rate-regulated activities. We have concluded that our specific fact pattern requires us to recognize financial assets and financial liabilities for certain aspects of our rate-regulated activities in accordance with the IFRS framework and applicable standards. We are in the process of completing our analysis of the measurement, presentation, and disclosure of these financial assets and liabilities within our IFRS financial statements. We anticipate that there would be no material impact on our net income or statements of financial position after the transition to IFRS. Our auditors are in the process of completing their audit of our opening IFRS balance sheet.

*Impact on Information Systems*
We have completed the implementation of our information system strategy that includes individual ledgers which will allow us to report financial information as required by our regulator and to report separately financial information under IFRS.

*IFRS 1*
IFRS 1, *First-time adoption of International Financial Reporting Standards*, outlines that, in general, an entity shall apply the principles under IFRS retrospectively and that adjustments arising on conversion to IFRS from existing Canadian GAAP shall be recognized directly in retained earnings. However, IFRS 1 provides a number of mandatory exceptions which prohibit retrospective application of IFRS. We will be in compliance with all of these mandatory exceptions. In addition, IFRS 1

outlines a number of optional exemptions from retrospective application of certain IFRS. We elected to take the following IFRS 1 optional exemptions at the date of transition:

- Business combinations – we selected the business combinations exemption which enabled us to avoid having to apply IFRS 3 - *Business Combinations* retrospectively. Accordingly, we did not restate business combinations that took place prior to the transition date.
- Employee benefits – we recognized all cumulative actuarial gains and losses at the date of transition to IFRS.
- Property, plant and equipment (PP&E) and intangible asset exemption for entities with rate-regulated activities – we used the carrying amount of all of our PP&E and intangible assets used in our rate-regulated activities as deemed cost at the date of transition to IFRS.

*Quantifying the Transition to IFRS*

We have completed our analysis of potential issues arising from our transition to IFRS. We do not anticipate any material adjustments to retained earnings or the Income Statement. IAS 16, paragraph 16 (c) indicates that we are required to recognize decommissioning and restoration obligations associated with the final retirement of our transmission system, but it does not require the recognition of interim retirements. As a result, we have determined that it is no longer appropriate to recognize such obligations. This position is consistent with the accounting policy of other transmission facility owners in Canada.

We have determined that it is appropriate to reflect the adjustments noted below in our first set of IFRS compliant financial statements, as of the transition date, i.e. January 1, 2010:

- The asset retirement obligation balance will be reduced to zero (from $186 million), the reserve for salvage costs liability balance will be increased (from $108 million to $173 million), and the property, plant and equipment balance will be reduced (by $121 million to $1,566 million). These adjustments affect balance sheet items only, offset each other and have no impact on the Income Statement or retained earnings.
- Customer contributions from property, plant and equipment will be reclassified to deferred revenue ($200 million)
- Certain assets will be reclassified from property, plant and equipment to intangible assets ($42 million).
- Differences between capitalized borrowing costs and AFUDC will be recorded as financial assets (nil at the date of transition - $13 million for the year ended December 31, 2010).
- Gains or losses on asset retirements will be recorded as financial assets or liabilities (nil at the date of transition - $5 million for the year ended December 31, 2010).
- Certain assets and liabilities related to rate-regulated activities will be recorded as financial assets and liabilities under IFRS. See Note 5 to the Financial Statements for a more detailed description of these items.

Although the foregoing changes will require adjustments or reclassifications within our financial statements under IFRS, we do not expect that there will be any material impact on our net income, retained earnings, or cash flow.

**Post Retirement Benefit Plans – Defined Benefit Pension Plans**

We have two post-employment defined benefit plans: the defined benefit pension plan (DBP) and the other post employment benefits plan (OPEB). On transition to IFRS, we intend to make the Following changes, which are expected to have an impact on our Financial Statements.

| Statement of Financial Position Item | C-GAAP | IFRS Adjustment | IFRS |
|---|---|---|---|
| *(in thousands of dollars)* | | | |
| Accrued pension asset (DBP) | $ 2,042 | $ (1,528) [1] | $ 514 |
| Pension asset offset (DBP) | (2,042) | 1,528 [1] | (514) |
| Other post retirement benefits accrued (OPEB) | (3,034) | 149 [2] | (2,885) |

1. Accrued pension asset: We intend to recognize unamortised actuarial losses of $1.5 million immediately; however, because we recover these costs through our transmission tariff, we intend to adjust the offsetting balance to equal the pension asset, and expect that there will be no impact on our retained earnings or net income.

2. Post retirement benefits accrued: On transition to IFRS, we intend to recognize unamortised actuarial gains of $0.2 million and unamortized vested past service costs of $0.1 million in retained earnings.

The differences between IFRS and C-GAAP for these items are that under C-GAAP we amortized actuarial gains or losses and past service costs over a period of time, i.e. the expected vesting period. Under IFRS we intend to recognize actuarial gains or losses as they occur, within other comprehensive income. We intend to recognize past service costs when they vest instead of recognizing them over time.

The net impact on retained earnings is expected to be $0.1 million.

Going forward, we intend to recognize any actuarial gains or losses and vested past service costs at the time we incur them. We intend to recognize actuarial gains or losses in Other Comprehensive Income and vested past service in the Income Statement. We expect that the net income impact related to the DBP will continue to be nil, as we intend to recover any expenses through existing adjustment mechanisms within our transmission tariffs.

*Impact on Reporting and Internal Controls*

We are currently updating and testing all entity level, information technology, disclosure and business process controls to reflect changes arising from the conversion to IFRS. We are making appropriate changes to internal controls over financial reporting and disclosure controls and procedures. Our internal audit group is currently reviewing all proposed new accounting treatment and procedures under IFRS.

*Training and Communication*

We are continuing to provide IFRS training for affected accounting, finance and operational staff. We will continue to roll out such training as we finalize accounting policies and procedures.

The IASB has a number of on-going projects on its agenda, which may result in changes to existing IFRS. Our IFRS team continues to assess new and amended accounting standards that the IASB issues during the conversion period and the potential impact of each on our financial statements.

## 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, 2010 (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, results of operations 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 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 adverse changes in the legislative and operating framework for Alberta’s electricity market (see Electricity Transmission in Alberta and Major Capital Projects;
- Decisions from the AUC concerning outstanding tariff and other applications which are consistent with past regulatory principles and are obtained in a timely manner (see Regulated Tariff Revenue);
- Approved rate-of-return and deemed capital structures for our transmission business which are sufficient to foster a stable investment climate (see Regulated Tariff Revenue);
- 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 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*" in this document 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 25, 2011. 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.

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