# MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

February 19, 2010

ALTALINK

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This Management's Discussion and Analysis (MD&A) reflects events known to us as of February 19, 2010. 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 19, 2010, based on the recommendation of our Audit Committee, which reviewed this MD&A in accordance with its terms of reference.

You should read this MD&A in conjunction with our legal advisory on Forward Looking Information, which we have included at the end of this MD&A, as well as our financial statements and the notes thereto. In particular, you should refer to our audited annual financial statements for the years ended December 31, 2009 and 2008 (the Financial Statements).

We have prepared our Financial Statements 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, 2008. We have disclosed any changes in our accounting policies in note 4 to our Financial Statements, including any changes that result from our initial adoption of new accounting standards. Unless otherwise noted, references in this MD&A to a "quarter" and "year" refer to the three month and twelve month periods ended December 31, 2009.

## Executive Summary

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 AltaLink Investments Limited Partnership (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 Inc. indirectly owns a 76.92% limited partnership interest in AHLP through subsidiaries and Macquarie Transmission Alberta Ltd. owns a 23.08% limited partnership interest in AHLP.

We provide customer value by focusing on excellence in our transmission operations, managing our environmental footprint, and building relationships in the communities we serve. We safely, reliably and efficiently deliver electricity to approximately 85% of Alberta's population under a wide variety of operating conditions and continuously changing customer demands. Our 212,000 square kilometre service area includes most major urban centres in Alberta, connecting generation plants to major load centres, cities and large industrial plants throughout central and southern Alberta.

We are a regulated electric utility under the jurisdiction of the Alberta Utilities Commission (AUC). Effective January 1, 2008, the AUC assumed responsibility from the Energy and Utilities Board (EUB) for regulating all investor-owned natural gas, electric and water utilities, certain gas pipelines and certain municipally-owned electric utilities. The AUC approves the tariffs we are permitted to charge to the Alberta Electric System Operator (AESO) by determining our revenue requirement on a forward test year basis.

We are the largest transmission facility owner in Alberta's electricity industry. Our transmission facilities comprise approximately half of the total kilometres in Alberta's high-voltage electricity transmission system and approximately half of gross plant invested in Alberta's integrated power grid, known as the Alberta Interconnected Electric System (AIES). Our system interconnects and operates synchronously (i.e., on the same phase and frequency) with other Alberta electricity transmission and distribution utilities. We also own and operate the facilities that interconnect British Columbia's transmission system with the AIES, allowing electricity to flow into and out of Alberta from the North American western interconnected system.

Our transmission system includes transmission lines, substations, telecontrol facilities and other related assets, which are generally situated on lands that we hold under easements, licences or permits for rights-of-way. We own and operate approximately 11,800 kilometres of 69kV to 500kV high-voltage transmission lines, most of which are overhead facilities. Lines are comprised of wood or metal support structures, conductors, foundations, insulators, connecting hardware and grounding systems. Our system includes approximately 270 substations, which are made up 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.

We monitor, control and manage our transmission facilities through our control centre, which operates continuously on a real-time basis and coordinates with the AESO and other transmission facility owners. We maintain and operate our own telecommunication system, including microwave radio, fibre optic cable, power line carrier and mobile radio systems. The reliability and availability of telecommunication services used in the management, protection and control of our transmission facilities enables us to provide safe, reliable and cost effective service to our customers. Other assets support the ongoing maintenance and operation of our transmission facilities. Other assets include office and service buildings, transport and work equipment and other office and information technology assets.

We employ approximately 500 people in management, technical, administrative and general labour positions. Approximately half of our people are members of either the United Utility Workers Association (UUWA) or the International Brotherhood of Electrical Workers (IBEW). We believe we have a constructive working relationship with both organizations, with no material grievances outstanding and no work stoppages since our inception. We are currently negotiating the renewal of both collective bargaining agreements, which expired on December 31, 2009.

## Our Vision, Strategy and Capability to Deliver Results

### Our Vision

We are committed to meeting the needs of our customers by providing a reliable, safe and cost-effective transmission grid. We believe in preparing for tomorrow while we power the lives of Albertans today. We focus on quality and continuous improvement. We believe in bringing forward the best and most innovative transmission practices, designs and solutions.

One of our core goals is creating customer value. We do that by listening, communicating and working with both customers and stakeholders who rely on us or are affected by our business. In addition, we believe it is important to give back to the communities in which we live and operate through financial support and employee participation.

### Our Strategy

Our strategic objective is to be the leading owner and operator of regulated electricity transmission in Alberta. To accomplish this objective, we will deliver safe, reliable and cost effective transmission of electricity for the benefit of Albertans and prudently expand our transmission network in Alberta. We will also investigate and assess any future opportunities to acquire regulated electricity transmission assets in Alberta.

Our growth strategy is broader than simply building new lines, substations and towers. Although we grow and expand our transmission network primarily by constructing new transmission facilities, we are always looking for innovative methods to get more out of the existing grid, such as re-using existing lines and implementing new technologies to minimize the impact on land use and landowners. We also partner with our stakeholders by improving our landowner consultation and reaching innovative agreements, such as two new partnerships with First Nations.

For more than 30 years, the capacity of the main backbone of Alberta's electric transmission grid has not kept pace with the significant growth in Alberta's economy. Growing demand for electricity and construction of new generation facilities has increased loading and congestion on the AIES. Over the past few years, electricity consumption in this province has increased by the equivalent of adding two cities the size of Red Deer every year and there is now a significant backlog of critical electricity transmission infrastructure. 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.

To cope with these increased demands, we expect that the AESO will direct us to upgrade and expand our transmission facilities over the next several years. As we complete capital projects, the capital cost of these will be included in our regulated rate base. We anticipate that our future tariffs will provide us with a fair return on our equity investments and to fully recover interest and operating expenses related to the ownership and operation of these assets.

## Our Capability to Deliver Results

We have numerous core competencies and resources that will enable us to achieve our corporate objectives.

***Financial strength***

We align our financing strategy with the regulated capital structure approved by the AUC and 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, AILP. Through their indirect ownership in AILP, SNC-Lavalin and 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. In doing 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 Inc. to provide engineering, procurement and construction management services for our capital projects. SNC-Lavalin has significant global experience in the electricity industry including the planning, design and construction of approximately 90,000 kilometres of transmission and distribution lines and approximately 1,500 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.

***Organizational leadership and people***

Our employees are the reason for our success and the key to our future. We employ 500 skilled and dedicated people, who work diligently to keep the lights on in Alberta. Our experienced leadership team is comprised of senior business leaders who bring a broad mix of skills in the electricity sector, finance, law, government, regulation, human resources and corporate governance. Our leadership team's experience and expertise, combined with our employees' knowledge and dedication to "keeping the lights on" through operational excellence, enables us to maintain our financial stability. 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 operate in an environment where there is strong competition for talented people. We expect competition for our specialized work force to remain strong, given the plans for significant transmission expansion in Canada and the United States. 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 encourage employee wellness and proactively provide opportunities for employee engagement, growth and development. To ensure that our people are engaged and aligned with our corporate strategies and business plans, we conduct employee engagement surveys. Our latest survey confirmed that our employees continue to be proud to work at AltaLink and value our focus on quality and customers, workplace safety, and job flexibility.

### *Environmental leadership*

We seek opportunities to provide environmental leadership through innovative practices and sound risk management. We employ our comprehensive environmental management system to manage the environmental risks and impacts related to our operations, including management of chemicals and spills, land and rights of way, treated wood and other waste. Where possible, we reduce our environmental footprint by using existing rights of way for new facilities and by applying technologies such as high voltage direct current transmission, which can reduce environmental impacts per energy unit transmitted. We are the first Canadian transmission utility to implement a comprehensive avian protection plan and have been at the forefront of applying new technologies such as Green Jacket, which protects wildlife from contact with substations.

### *Regulation*

We proactively build trust and confidence with stakeholders by following transparent processes and striving for regulatory efficiency.

### *Stakeholder engagement*

Our robust stakeholder engagement practices provide our audiences with timely, easy to understand information about transmission projects. Our key to success is our process, which 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.

# How We Measure Our Performance

## Delivering Customer Value

We use key measures to determine whether we are meeting our goals and the needs of our customers. These key measures include a mix of operational, risk management and financial metrics. The Canadian Electricity Association (CEA) provides benchmarking data for several of our key measures, allowing us to compare our performance against other transmission facility owners in Canada. Our performance has compared favourably with the CEA benchmarks for reliability, safety and cost effectiveness since we acquired the Transmission Business in 2002.

### *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. Despite our strong track record, we continually strive to further reduce the duration of system outages for the benefit of our customers.

| | Year ended | | | |
|---|---|---|---|---|
| | **2009** | 2008 | 2007 | 2006 |
| Frequency of outages (SAIFI) [1] | | | | |
| AltaLink | 0.96 | 1.12 | 1.38 | 1.01 |
| CEA benchmark [3] | N/A | N/A | 1.61 | 1.70 |
| Duration of outages (SAIDI) [2] | | | | |
| AltaLink | 0.64 | 1.77 | 1.35 | 0.58 |
| CEA benchmark [3] | N/A | N/A | 1.14 | 1.52 |

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. Benchmark statistics from the Canadian Electrical Association are provided on a transmission basis.

### *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. While our safety statistics for 2009 are comparable with recent industry benchmarks, they are worse than our safety performance for the preceding five year period. To help bring our safety performance back to top quartile rankings, we have implemented a Safety Management Initiative, looking at every aspect of our safety systems – from our safety practices and procedures to our leadership. We continue to conduct detailed assessments and are implementing actions to improve on our 2009 safety performance and a return to continuous improvement.

| | Year ended | | | |
|---|---|---|---|---|
| | **2009** | 2008 | 2007 | 2006 |
| All Injury Frequency Rate [1] | | | | |
| AltaLink | 1.42 | 0.73 | 1.02 | 0.89 |
| CEA benchmark [2] | N/A | 2.88 | 2.93 | 2.92 |

1. Number of lost time accidents and medical aid incidents per 200,000 man-hours worked by employees and contractors.
2. Benchmark statistics from the Canadian Electrical Association are provided on a transmission basis.

### *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, and unit cost based estimating. We will continue to seek business improvements across our organization while delivering reliable and safe transmission service to our customers.

## Financial and Operational Performance

### *Growth in regulated capital assets*

We measure growth in our regulated capital assets (both rate base and assets under construction) 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 assets under construction by the equity ratio and rate of return approved by the AUC in its generic cost of capital decisions. 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 interest costs and return on equity attributed to our assets under construction. We do not receive cash flow related to our assets under construction until the projects are completed and added to our rate base.

In our 2009-10 general tariff application, we provided the AUC with a forecast of capital expenditures for the two year test period. In this forecast, we projected that our rate base and assets under construction would increase significantly during 2009 and 2010 as a direct result of the much needed capital investment to expand and reinforce Alberta's transmission infrastructure. The table below summarizes our 2009 and 2010 capital forecasts:

### *Mid-year rate base and assets under construction*

| | **2010 Forecast** | **2009 Estimate** |
|---|---|---|
| | **(in millions of dollars)** | |
| Mid-year rate base | $ 1,248.6 | $ 1,054.9 |
| Mid-year assets under construction | $ 363.4 | $ 204.2 |

We exceeded our 2009 growth targets by undertaking additional capital projects at the AESO's direction. Our 2010 capital forecast is based on approximately $605.1 million of capital expenditures, including $488.6 million of additions to our rate base. The balance of our forecast capital program will increase our assets under construction. Our actual 2010 capital program may vary significantly from our forecast, depending on the timing of regulatory approvals, directions from the AESO, and other factors beyond our control.

### *Transmission tariff revenue*

The revenue requirements approved by the AUC form the basis for recognizing our transmission tariff revenue. In December 2009, we submitted a compliance filing to the AUC, in which we recalculated our revenue requirements for 2009 and 2010 to reflect the 2009-10 GTA Decision and the 2009 GCOC Decision. In this compliance filing, we estimated our aggregate revenue requirements for 2009 and 2010 to be $282.2 million and $290.5 million respectively. In the future, our revenue requirements will be appropriately adjusted to reflect the impact of deferral accounts (such as direct assign capital expenditures, long-term debt interest and property taxes), any changes in our regulated capital structure and allowed return on equity, and other regulatory tariff adjustments.

## Regulatory Decisions

On October 2, 2009, the AUC issued Decision 2009-151 (2009-10 GTA Decision) dispensing with our 2009-2010 general tariff application. The AUC later released Decision 2009-216 (2009 GCOC Decision) on November 12, 2009, concluding its 2009 Generic Cost of Capital proceeding. The AUC stated that it was in the best interest of ratepayers to maintain our 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. We recently submitted our compliance filing requesting the AUC to adjust our revenue requirements for 2009 and 2010 to give effect to both decisions.

### *Generic cost of capital*

The 2009 GCOC Decision continued the AUC's generic approach to regulatory cost of capital matters for electricity and natural gas utilities under its jurisdiction. The generic cost of capital sets the deemed capital structure, expressed as proportions of debt and equity, for each utility and prescribes a generic return on equity to be applied against the common equity allowed in the deemed capital structure. We are required to use our deemed capital structure and the generic return on equity when calculating our tariff revenue requirements.

In its 2009 GCOC Decision, the AUC increased our equity ratio to 36% from 33% and increased the generic return on equity to 9% from the interim rate of 8.75%. The approved generic return on equity will remain in effect for 2009 and 2010 and, on an interim basis, for 2011. The AUC decided not to continue with the previous adjustment formula for the generic return on equity, which resulted in generic returns on equity 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 with this adjustment formula, the generic return on equity would have been set at 8.61% for 2009.

### *General tariff application for 2009 and 2010*

The 2009-10 GTA Decision contains various directives related to our 2009-2010 general tariff application, including approval of increases in operating expenses, property taxes, depreciation rates, capital expenditures for capital replacement and upgrade programs, costs relating to increasing our bank credit facilities from $285 million up to $600 million, and continuing with deferral accounts for long-term debt interest costs, property taxes and direct assigned capital expenditures. In denying our request for a management fee on customer contributed projects, the AUC indicated that this issue will be addressed in a future proceeding.

In our 2009-2010 general tariff application, we forecast increases to our revenue requirement due to projected growth in our rate base and capital expenditures outlook. In the 2009-10 GTA Decision, the AUC demonstrated its support for our credit ratings by: (i) directing the continued use of the future income tax method, (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.

### *Long-term debt*

On October 15, 2009, the AUC issued Decision 2009-165 approving our application to issue up to $300.0 million of long-term debt before March 31, 2010. We plan to use the proceeds of future long-term debt issues to fund our capital investment program.

## Revenue Requirements

### *Revenue requirements for 2007 and 2008*

On February 16, 2007, the AUC issued Decision 2007-012 regarding our 2007-08 general tariff application. This decision also settled three deferral accounts and our self-insurance reserve from May 1, 2004 to December 31, 2005. On June 19, 2007, the AUC issued Decision 2007-050 to approve our compliance filing for our 2007 and 2008 revenue requirements.

On August 26, 2008, the AUC issued Decision 2008-076 confirming full recovery of our Direct Assign Capital Deferral Account (DACDA) and other deferral accounts for May 1, 2004 to December 31, 2006. On January 30, 2009, the AUC directed us to settle the related regulatory assets and liabilities of $1.4 million, which we paid to the AESO on February 17, 2009.

***Revenue requirements for 2009 and 2010***

On December 23, 2009, we submitted a compliance filing to the AUC, in which we recalculated our revenue requirements for 2009 and 2010 by giving effect to the 2009-10 GTA Decision and the 2009 GCOC Decision. In the future, these revenue requirements will be appropriately adjusted to reflect deferral accounts (such as direct assign capital expenditures, long-term debt interest and property taxes), any changes in our regulated capital structure and allowed return on equity, and other necessary regulatory tariff adjustments. The compliance filing also included prior year adjustments to various deferral accounts. On January 27, 2010, the AUC granted interim rate increases, pending its review of our compliance filing.

Except for the Genesee to Langdon 500kV Project Costs, which are discussed below, our revenues for the twelve months ended December 31, 2009 are consistent with the compliance filing. Our interim financial statements for the nine months ended September 30, 2009 reflected an interim tariff increase of 3% awarded by the AUC effective January 1, 2009, pending the 2009-10 GTA Decision. Our revenues for the three months ended December 31, 2009 give effect to the compliance filing retroactive to January 1, 2009.

The table below summarizes the revenue requirements included in the compliance filing:

| | Year ending December 31, | | |
|---|---|---|---|
| | **2010** | 2009 | 2008 |
| | Compliance Filing [1] | Compliance Filing [1] | Approved [2] |
| | | **(in millions of dollars)** | |
| Return on equity | 43.0 | 33.9 | 29.9 |
| Return on debt | 51.7 | 38.5 | 39.6 |
| Operating costs | 91.2 | 84.4 | 78.3 |
| Miscellaneous revenue | (7.1) | (7.0) | (6.1) |
| Depreciation and amortization | 92.5 | 77.0 | 77.3 |
| Income taxes | 14.7 | 11.2 | 9.7 |
| Revenue requirement before Genesee to Langdon 500 kV | 286.0 | 238.0 | 228.7 |
| Genesee to Langdon 500 kV | 4.5 | 44.2 | — |
| Revenue requirement | 290.5 | 282.2 | 228.7 |

1. The amounts that the AUC may ultimately approve may vary from the amounts applied for in our compliance filing.
2. Revenue requirements for 2008 reflect Decision 2007-012, Decision 2007-050, Decision 2008-076 and AUC Orders regarding the generic cost of capital.

### *Genesee to Langdon 500 kV project costs*
The EUB, in Decision 2007-075 voided the Genesee to Langdon 500 kV Project based on a finding that the EUB's administration of the hearings had "accumulated into a reasonable apprehension of bias". In our 2009-2010 general tariff application, we asked the AUC to include approximately $38.6 million of costs related to the Genesee to Langdon 500 kV Project in our 2007 rate base. In its 2009-10 GTA Decision, the AUC: (i) stated that we should not be harmed financially by the project's cancellation; (ii) directed us to invoice the AESO for $35.0 million of the project costs; and (iii) directed us to recover the balance of the project costs in our 2009-10 revenue requirements. Pursuant to the AUC's directions, we invoiced the AESO for $35.0 million and included in our compliance filing a request to recover the balance of the project costs, financing costs since the cancellation of the project, and recovery of income taxes related to the project costs.

On December 1, 2009, the AESO applied to the AUC to review and vary the 2009-10 GTA Decision. In doing so, the AESO asked the AUC to direct us to recover the $35.0 million amount under our 2009-10 tariffs. The AESO paid $35.0 million to us on December 31, 2009, pending the AUC's decision on the AESO's review and variance application. When the AUC issues its decision, the effects of the decision will be recorded in the financial statements for the period in which the decision is issued.

Prior to the 2009-10 GTA Decision, we accounted for the voided 500 kV project costs as capital assets, consistent with our 2009-2010 general tariff application. Following the 2009-10 GTA Decision, we reclassified the remaining net book value of $36.7 million from capital assets to regulatory assets. When the AUC rules on our compliance filing, we will recognize the difference, if any, between the amount we are allowed to recover and the amounts we previously recognized in our financial statements. We expect that the AUC's ruling on our compliance filing will not have a material adverse impact on our financial results.

### *Direct assign capital deferral account*
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 by way of the DACDA. The DACDA reflects the difference between the forecast and actual costs of direct assigned capital projects added to the regulatory rate base. We have recognized revenue consistent with an application that we filed with the AUC on December 23, 2009 to settle our DACDA for 2007 and 2008.

### *Future income taxes*
As a limited partnership, we do not pay federal or provincial income taxes directly. Instead, our income taxes are paid by the corporations that ultimately hold limited partnership interests in us. Our revenue requirement includes an allowance for income taxes attributable to our regulatory net income. In calculating this allowance, we currently use the future income tax method for federal income taxes and the flow-through method for provincial income taxes. In its 2009-10 GTA Decision, the AUC approved our request to continue using the future income tax method for federal income taxes. By continuing to allow the future income tax method for federal income taxes, the AUC provides us with higher tariffs and cash flow to support our cash flow credit metrics during the construction of major transmission projects. Previously, in Decision 2007-012, the AUC had directed us to switch to the flow-through method for federal income taxes in 2009 and subsequent years. The AUC approved AltaLink's proposal to continue to use the future income tax method in determining deemed federal income tax expenses in 2009-10. The AUC indicated that it will review the necessity for a further delay in implementation at the time of our next GTA. The AUC has also directed us to recommend options as to the disposition of federal future income taxes paid to us in previous periods.

### *Non-traditional accounting measures*
In Decision 2009-151, the AUC stated that we may apply for certain non-traditional regulatory accounting measures to sustain cash flow credit metrics consistent with our current credit ratings. If we proceed with large multi-year capital projects, our debt service obligations would increase due to the additional debt we would incur to fund construction work in progress. Under traditional regulatory accounting, interest and return-on-equity related to construction work in progress (referred to as Allowance for Funds Used During Construction or AFUDC) are capitalized during construction and included in the regulatory rate base at completion. In the United States, regulators have allowed utilities to include AFUDC related to major transmission projects in annual tariffs. The Ontario Energy Board has also stated that it may consider similar measures for major transmission projects within its jurisdiction. In the future, we may apply for similar non-traditional

regulatory accounting measures if we require further regulatory support to sustain our credit metrics during major transmission project construction.

## 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 much needed transmission infrastructure. For more than 20 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 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 (TFOs) to upgrade and expand the AIES over the next several years, consistent with: (i) the Alberta Government's recently announced Provincial Energy Strategy; (ii) the Transmission Regulation; and (iii) the AESO's 10-year transmission system plan, its 20-year transmission system outlook, and the AESO's current and anticipated need applications. The AESO has already directed us to proceed with facility applications related to several major projects contemplated within its long range plans.

On December 11, 2008, the Alberta Government announced its Provincial Energy Strategy which included commitments to strengthen Alberta's transmission system. The Provincial Energy Strategy notes the urgency and importance of upgrading the AIES and, among other things, commits the Alberta Government to develop a plan identifying the requirements, technical solutions and schedules for a comprehensive upgrade to the transmission system. It also includes commitments to adopt and implement policies to: (i) build transmission facilities to areas of renewable or low-emission electricity generation; (ii) to build interties to other markets; and (iii) support the development and deployment of "smart grid" technologies.

The Provincial Energy Strategy also states that the Alberta Government intends to review and streamline the regulatory processes for transmission siting, including legislative amendments resulting from the enactment of the *Electric Statutes Amendment Act, 2009* and recent amendments to the Transmission Regulation.

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 Statutes 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 extensively 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 the case of critical transmission infrastructure, the Minister may determine eligibility through competitive bidding or some other process. Under the Transmission Regulation, the AESO has established rules or practices respecting competitive tenders, the preparation of cost estimates, project scope documents and schedule documents for projects.

## 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 of regional upgrades.

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

The following table summarizes our current major capital projects:

| | | Project Status | |
|---|---|---|---|
| Project | Description | Need Application | Facility Application |
| South West 240 kV Project | Double circuit 240 KV transmission line and substations under construction between Pincher Creek and Lethbridge to interconnect wind generation planned in southwest Alberta. | Approved by AUC on May 17, 2005 | Approved March 10, 2009 |
| Southeast Alberta Transmission Development | Regional transmission facilities to meet forecast customer load growth, restore the Alberta-Saskatchewan tie to its path rating, and enable the interconnection of proposed wind generation projects in southeast Alberta. | Approved by AUC on July 11, 2008 | 10 facility applications filed, of which seven have been approved. |
| Southern Alberta Transmission Reinforcement | Large-scale project to construct transmission lines and substations across southern Alberta to interconnect up to 2,700 MW of proposed wind generation projects. | Approved by AUC on September 8, 2009 | Directed by AESO to prepare multiple facility applications. First facility applications expected in 2010. |
| Keephills 3 Generation Interconnection Project | Interconnect expansion of coal-fired generation facilities at Keephills, west of Edmonton. | Approved by AUC in 2008 | Four of five facility applications approved. |
| Western Alberta Transmission Line | Reinforce system backbone between Edmonton and Calgary. | Designated as critical transmission infrastructure | Directed by AESO to submit facility application. |
| Heartland Region | Double circuit 500kV transmission line between Ellerslie and a new substation in Gibbons-Redwater area. | Designated as critical transmission infrastructure | Directed by AESO to submit facility application. |
| Edmonton Region 240 kV Transmission System Upgrades | Debottleneck system in Edmonton region for load growth and decommissioning of coal-fired generation. | Approved by AUC on February 24, 2009 | Two of five facility applications filed in late 2009. |

### *South West 240 kV project*

We are currently constructing a double circuit 240 kV transmission line in southwest Alberta between Pincher Creek (Goose Lake) and Lethbridge, together with related upgrades required to interconnect large volumes of wind generation planned for the region. Our most recent estimate of project costs is approximately $199 million, plus or minus 10%. We anticipate that the transmission facilities for the South West 240 kV Project will be energized and added to the regulatory rate base in 2010.

On August 10, 2007, we filed a facility application with the AUC for approval to construct and operate the main transmission facilities for the South West 240 kV Project. A five-day public hearing was held in Lethbridge, Alberta in December 2008 and, on March 10, 2009, the AUC issued Decision 2009-028 approving our facility application. Since the proposed transmission lines cross First Nations reserve lands, we have also obtained all required consents of the chiefs and councils of the affected First Nations to federal permits issued by Indian and Northern Affairs Canada under the Indian Act (Canada). In doing so, we entered into innovative arrangements that enable the First Nations to acquire non-controlling interests in the transmission facilities situated on the First Nations reserve lands.

### *Southeast Alberta transmission development*

On November 5, 2007, the AESO filed a need application with the AUC proposing a two-phase approach to addressing the need for transmission system development in southeast Alberta. The first phase identifies regional transmission facilities which are immediately required to meet forecast customer load growth, restore the Alberta-Saskatchewan intertie near to its path rating, and enable the interconnection of approximately 141 MW of proposed wind generation projects in southeast Alberta. The second phase, the *Southern Alberta Transmission Reinforcement* described below, would address the necessary transmission system development required to interconnect future wind generation facilities beyond the reliability threshold in southeast Alberta.

After the AUC approved its need application for the first phase on July 11, 2008, the AESO directed us to file facility applications for the required transmission facilities except for certain facilities in the Medicine Hat area that are now part of the Southern Alberta Transmission Reinforcement project. We have since filed ten separate facility applications, seven of which the AUC had approved as of January 31, 2010. We estimate the aggregate project costs to be approximately $77 million, plus 20% and minus 10 %. We have completed construction of some portions of the project and, if the remaining three facility applications are approved by the AUC in a timely manner, we anticipate that the entire Southeast Alberta Transmission Development will be completed 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's transmission plan forecasts that 2,000 to 3,900 MW of wind generation facilities will be operating in Alberta within the next ten years. Of these, between 1,700 MW and 3,200 MW are forecast to be operating in southern Alberta, including approximately 500 MW currently in operation.

The *Southern Alberta Transmission Reinforcement* is located within our service territory and the AESO has directed us to prepare facility applications for those facilities identified in Stage I and Stage II, of the AESO's need application, which the AUC approved on September 8, 2009. We have received direction letters or request for services from the AESO for $104 million to prepare facility applications and begin project engineering and the procurement of necessary long-lead time equipment to maintain project schedules. We expect to begin filing facility applications in 2010 and to begin construction as early as 2011.

In its need application, the AESO estimated the cost for the entire project to be approximately $1.8 billion, plus 30% and minus 15% in 2008 dollars. The AUC approved the need application for the entire multi-stage project and directed the AESO to set appropriate triggers for the development of Stages II and III. Stage I will enable wind generation facilities capable of producing at least 1,700 MW to be operating in southern Alberta over the next 10 years. Stage I development is currently forecast to cost approximately $750 million, plus 30% and minus 15% in 2008 dollars. The AESO has the opportunity to reduce the scope, cost and impact of other 138 kV reinforcements to the Medicine Hat area infrastructure, previously approved by the AUC for the *Southeast Alberta Transmission Development, by* advancing changes and upgrades in Stage II of the *Southern Alberta Transmission Reinforcement* in parallel with Stage I.

### *Keephills 3 generation interconnection project*

We are working on several transmission projects required to interconnect the expansion of the TransAlta/EPCOR 450 MW coal-fired generation facilities at Keephills, west of Edmonton. After the AUC approved the AESO's need applications for the *Keephills 3 Generation Interconnection* project in 2008, the AESO directed us to file facility applications for the required transmission facilities. The project costs include approximately $4 million for upgrades to station service and approximately $75 million, plus 20% and minus 10%, for the five separate facility applications that comprise the remainder of the project. We expect that approximately $64.4 million of project costs will be system costs invested by us and that the remaining $14.6 million will be contributed by the interconnected generator. We have filed all five facility applications with the AUC, of which four have been approved as of January 31, 2010 and are proceeding with construction on the approved portions.

### *Western Alberta transmission line*

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 10-year 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.

Reinforcement of the transmission system between the Edmonton and Calgary regions is needed to:

- avoid reliability issues for consumers in south and central Alberta;
- improve the efficiency of the transmission system;
- restore the capacity of existing interties; and
- avoid congestion, which prevents the electricity market from achieving a fully competitive outcome.

Transmission constraints and congestion also slows development of new competitive generation in the Edmonton area and further north.

The AESO's 10-year transmission system plan contemplates meeting the long-term capacity requirement for the Edmonton to Calgary component of the bulk system using two high voltage direct current transmission lines, each with a capacity of 2,000 MW. The preferred orientation for one of these lines, referred to as the *Western Alberta Transmission Line*, is between converter stations to be built in the Wabamun Lake area and near Langdon. In its 10-year transmission system plan, the AESO estimated the cost of the 2,000 MW Western Alberta Transmission Line to be approximately $1.5 billion.

Under the *Electric Statutes Amendment Act, 2009*, the Western Alberta Transmission Line has been designated as critical transmission infrastructure. The *Electric Statutes Amendment Act, 2009* provides for a staged approach to the project by requiring an initial capacity of at least 1,000 MW that is expandable to a minimum capacity of 2,000 MW. At the direction of the AESO, we are preparing cost estimates using the lower initial capacity and are taking steps toward filing a facility application with the AUC, including an extensive public consultation program.

### *Heartland region*

The AESO's 10-year transmission system plan identifies significant system upgrades required to meet the expected increased electricity demand due to residential, commercial and industrial growth in the region northeast of the Edmonton area, known as the Heartland Region. The increase in demand for electricity is expected to require major transmission reinforcement into the Fort Saskatchewan area, including the possible construction of a 500 kV transmission facility. In April 2007, the AESO began consulting with industry participants and landowners in developing these plans.

The Heartland Region has been designated as critical transmission infrastructure under the *Electric Statutes Amendment Act, 2009*. We expect that portions of the Heartland Region development will be located across or in close proximity to the boundaries between our service territory and that of EPCOR. To facilitate the construction and operation of safe, reliable and efficient facilities, EPCOR and we have agreed to cooperate and share equally in the development of new facilities which may be sited within both service territories.

EPCOR and we have received requests for services from the AESO to perform various activities. In April 2009, EPCOR and we began notifying and consulting with stakeholders about this project. We have identified two preferred routes and, after further consultation with stakeholders, will file a facility application with the AUC early in 2010.

### *Edmonton region 240 kV transmission system upgrades*

The AESO has identified the need for transmission system reinforcement in the Edmonton region to remove bottlenecks which restrict transmission capability, to address the changes in power system flows due to the retirement of Wabamun Unit #4, and to meet the increasing electrical demand in Edmonton and the northeast region. The proposed development identified in the approved need application is estimated to cost approximately $125 million, plus 30% and minus 30%.

After the AUC approved the AESO's need application for the Edmonton Region 240 kV Transmission System Upgrades on February 24, 2009, the AESO directed us to submit facility applications to meet the need for the project. We have begun activities required to submit five facility applications to the AUC, including further definition of project functional specifications, engineering and landowner consultation. We have already filed two facility applications with the AUC and expect to file the remaining three facility applications in 2010.

### *Additional regional area developments*

In the AESO's 10 year transmission system plan released in June 2009, the AESO identified the need to upgrade transmission facilities within several geographic regions of Alberta. These upgrades are needed to meet forecast customer load requirements as well as to interconnect future generation projects. Depending on the specific transmission developments ultimately selected by the AESO to meet the transmission requirements within these regions, the estimated order of magnitude as to the potential investment in transmission facilities in these regions may exceed $1 billion.

We have received direction letters or requests for services from the AESO regarding proposed transmission developments in the Hanna, Red Deer, Yellowhead, and Central-East regions. These activities include order of magnitude estimates for the AESO need applications, preliminary engineering to develop project proposals for the AESO, and the commencement of activities, including landowner consultation, required to submit facility applications to the AUC. We expect to begin filing facility applications for projects related to these regional developments in 2010.

### *Foothills area transmission development project*

We are currently working on conceptual plans to integrate future wind generation, enabled by the Southern Alberta Transmission Reinforcement, into the Calgary region. The proposed project will expand and upgrade several substations and transmission lines in the south Calgary region.

The AESO has issued direction letters to us to prepare and file facility applications for a double circuit 240kV line connecting the Aldersyde to South Calgary (Janet) area. This project is required to coordinate with the west side of the Southern Alberta Transmission Reinforcement projects. These projects will be filed concurrently with the AESO need application. We are currently working on consultation plans for 2010.

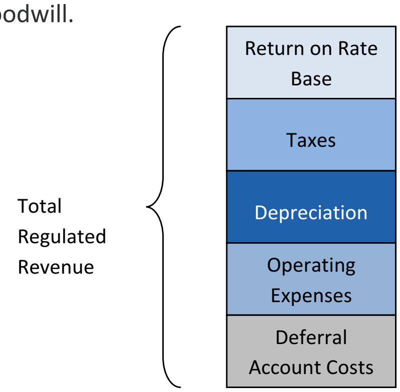
# Transmission Tariffs

## Overview

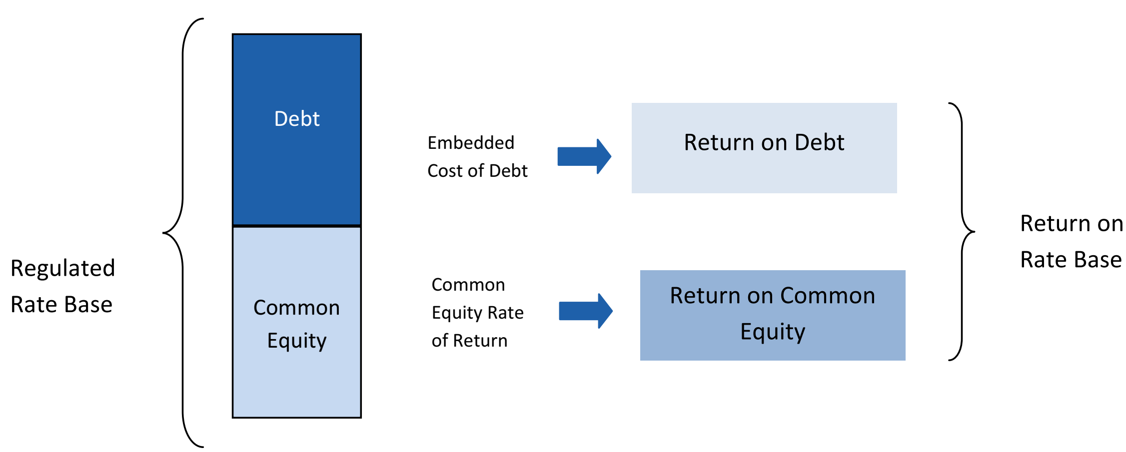
The AESO pays transmission tariffs to us in equal monthly instalments, without regard to either the price or volume of electricity transmitted through our Transmission System.

The revenue requirements underlying our transmission tariffs must be approved by the AUC. Under the Electric Utilities Act, the AUC must provide us with a reasonable opportunity to recover our forecast costs, including operating expenses, depreciation, cost of debt capital and taxes associated with investment, and a fair return-on-investment. Under the Transmission Regulation, in setting our tariff, the AUC must consider that providing consumers with unconstrained transmission access to competitive electricity markets is in the public interest. This helps to provide 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.

The following diagram outlines the principal components of our revenue requirement. With the exception of the return on rate base, the revenue requirement approved by the AUC is determined on a forward test year basis and is intended to enable us to recover our forecast costs. Our revenue requirement does not include any return on equity or debt associated with non-regulated assets, such as our goodwill.




The regulatory return on rate base is intended to provide us with a fair return on the capital we invest in our regulated rate base, according to the deemed capital structure, embedded cost of debt, and common equity rate of return approved by the AUC. The embedded cost of debt is determined through our general tariff applications. The AUC has been setting the common equity rate of return and capital structure through generic cost of capital proceedings. Our actual capital structure may vary from the proportions of debt and common equity in the deemed capital structure set by the AUC.



## Liquidity and Capital Resources

### Liquidity

We generally issue commercial paper to finance our day-to-day cash requirements. Between our $400.0 million commercial paper backstop facility and our $85.0 million operating line of credit, we believe that our liquidity is sufficient to finance our planned operations and capital projects. As at December 31, 2009, we had issued $48.0 million under our commercial paper program, leaving us with $437.0 million of available liquidity under our bank credit facilities.

In late 2008 and early 2009, commercial paper markets were significantly less active due to the global credit crisis. We occasionally relied on our commercial paper backstop facility for brief periods of time when commercial paper markets were effectively closed. Since then, we have been able to issue commercial paper on normal terms without disruption.

We significantly increased our capital expenditure program during 2009 and we expect that our capital expenditures will be even higher for the next several years. 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.

In the 2009-10 GTA Decision, the AUC approved our request to increase our bank credit facilities from $285.0 million to a maximum of $600.0 million. In December 2009, we doubled the size of our commercial paper backstop facility from $200.0 million to $400.0 million by adding three new lenders to our banking syndicate. Our credit facilities currently total $485.0 million and we may further increase these facilities if warranted by our capital expenditure program.

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 amounts received from customers for construction projects and retain investment income we earn on amounts received from customers for future operating and maintenance costs.

| | **December 31, 2009** | December 31, 2008 |
|---|---|---|
| | **(in millions of dollars)** | |
| Cash and cash equivalents, beginning of year | **$ —** | $ — |
| Cash flow from (used in) | | |
| Operating activities | **124.1** | 138.4 |
| Investing activities | **(218.3)** | (140.5) |
| Financing activities | **102.5** | 2.1 |
| Cash and cash equivalents, end of year | **$ 8.3** | $ — |
| **Ratios** [1] | | |
| Interest coverage: [2] | | |
| EBIT coverage [2, 3] | **2.32x** | 1.96X |
| EBITDA coverage [2, 4] | **4.21x** | 3.75X |
| FFO coverage [2, 5] | **2.67x** | 2.67X |
| FFO/debt [6] | **14.11%** | 13.74% |
| Debt/total capitalization [7] | **54.42%** | 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 - Net income before interest expense and income taxes (EBIT) divided by interest expense.
4. EBITDA coverage - Net income before interest expense, income taxes, 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.
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 limit of 75%.

## Non-GAAP Financial Measures

We use certain financial metrics, as noted in the table above, 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 EBIT and 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 other income and 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. You should not consider FFO 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.

## Cash Flows

### *Operating activities*

During 2009, our operating activities provided cash of $124.1 million, compared with $138.4 million generated during 2008. As discussed below, substantially all of this decrease resulted from changes in non-cash working capital. Funds generated by operations, before changes in non-cash working capital, totalled $114.4 million during 2009, an increase of $1.0 million from 2008. Of the $15.8 million increase in our net income, $8.1 million was derived from allowance for funds during construction, which was capitalized to assets under construction, and $3.0 million related to the change in gains on disposals of capital assets. Our non-cash accretion expense increased by $5.9 million while non-cash adjustments for long-term regulatory assets and liabilities was $9.1 million greater than during the preceding year.

During 2008, working capital provided cash of $25.0 million, most of which related to the timing of monthly payments from the AESO. Monthly payments from the AESO are always received when due, twenty working days following the end of the previous month. Because two payments were outstanding on December 31, 2007, we received thirteen monthly payments from the AESO during 2008, compared with twelve payments during 2009. During 2009, we increased our accounts payable and accrued liabilities related to operating activities by $5.6 million and our accounts receivable increased by $3.5 million because our estimated revenue requirements were higher than the interim tariffs paid by the AESO. Also during 2009, our prepaid expenses and deposits decreased by $3.8 million as deposits paid on long-lead materials were capitalized to capital projects when the materials were delivered.

For the fourth quarter of 2009, cash provided by operating activities increased by $39.3 million mainly due to the increase in net income for the fourth quarter of $21.7 million, increase in depreciation expense for the fourth quarter of $19.6

million and an increase in non-cash working capital items of $3.6 million. The increase in non-cash working capital items was mainly due to an increase in accounts payable and accrued liabilities related to operating activities.

### *Investing activities*

Our investing activities included capital expenditures, net of the change in non-cash working capital items, of $292.6 million during 2009 compared to $174.2 million invested during 2008. These capital expenditure amounts include $98.7 million and $66.0 million respectively for the fourth quarter of each year.

During 2009, we increased our capital replacement and upgrade program by $23.6 million compared to 2008. We started construction of our Southwest Project and other projects approved by the AUC, and continued with construction of projects approved in prior years. We also increased activities related to obtaining regulatory approval for proposed capital projects, including our Southern Alberta Transmission Reinforcement, Heartland, and Keephills projects. Please refer to the "Major Capital Projects" section of this MD&A for more information regarding our major capital projects.

We moved forward with capital projects funded by customer contributions, transferring $70.6 million to our general bank accounts to pay for construction costs compared with $32.9 million during 2008. We also received proceeds of $3.8 million from disposals of land pursuant to expropriations by the Government of Alberta for urban ring road construction projects.

For the fourth quarter of 2009, our cash used in investing activities increased by $41.9 million due to an increase in capital expenditures of $98.7 million, offset by an increase in customer contributions transferred to our general bank account of $56.9 million.

### *Financing activities*

During 2009, our financing activities provided cash of $102.5 million, an increase of $100.4 million (decrease of $5.1 million compared to the fourth quarter of 2008) compared with last year. In 2008, we distributed $22.0 million to AILP and funded substantially all of our capital projects from operating cash flow. In 2009, with the increase in capital spending, we received equity investments totalling $140.5 million from AILP and proceeds of $102.8 million from issuing medium term notes. After reducing our bank credit facilities by $117.1 million and paying distributions of $22.8 million to AILP, we applied the balance of these proceeds to finance our capital expenditure program.

During 2009, the additional equity was provided to finance our 2009 capital expenditure program, to increase our equity ratio pursuant to the 2009 GCOC Decision, and to contribute additional equity in anticipation of our 2010 capital expenditure program.

For the fourth quarter of 2009, our cash provided by financing activities increased by $10.9 million, mainly due to an equity contribution from AILP of $94.0 million, offset by an increased reduction of our bank credit facilities of $77.3 million and distributions paid to AILP of $5.7 million.

## Earnings Coverage

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

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 net 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 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.
4. 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, 2009** | December 31, 2008 |
| **Credit Ratings** | | |
| DBRS – Commercial Paper | **R-1 (low)** | **R-1 (low)** |
| DBRS – Senior Secured Bonds | **A** | **A** |
| Standard & Poors – Senior Secured Bonds | **A-** | **A-** |

On April 21, 2009, Standard & Poors confirmed the above rating with a stable trend. On October 7, 2009, following the 2009-10 GTA Decision, DBRS issued a comment letter confirming the above ratings with a negative trend, pending the 2009 GCOC Decision. On November 30, 2009 following the 2009 GCOC Decision, DBRS confirmed its ratings at "A" and R-1 (low) and changed the trend to stable from negative.

Standard & Poors' ratings apply to AltaLink, L.P, and its senior secured obligations. Standard & Poors' long-term issuer and long-term issue credit rating scales range from AAA to D, which represents the range from highest to lowest quality. According to Standard & Poors, an issuer rated "A" has a strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories. According to Standard & Poors, an obligation rated "A" is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligations in higher-rated categories. However, the obligor's capacity to meet its financial commitment on the obligation is still strong. Adding a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories.

DBRS' ratings apply to AltaLink's senior secured obligations and senior unsecured obligations under the [Commercial Paper Program]. DBRS's long-term debt credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest credit quality of such securities rated. According to DBRS, a rating of A by DBRS is in the middle of three subcategories within the third highest of eight major categories; such rating is assigned to debt securities considered to be of satisfactory credit quality and for which protection of interest and principal is still substantial, but the degree of strength is less than that of AA rated entities. While "A" is a respectable rating, entities in this category are considered to be more susceptible to adverse economic conditions and have greater cyclical tendencies than higher rated entities. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. The absence of either a "(high)" or a "(low)" modifier indicates that the rating is in the middle of the category.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issuer of securities. The credit ratings accorded to AltaLink are not recommendations to purchase, hold or sell securities of AltaLink inasmuch as such ratings are not a comment upon the market price of the securities or their suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgement, circumstances so warrant.

## Results of Operations

### Selected Financial Information

Selected annual financial information derived from our financial statements for the most recent period is detailed below:

| | Year ended | | |
|---|---|---|---|
| | **December 31, 2009** | December 31, 2008 | December 31, 2007 |
| | **(in millions of dollars except per unit amounts)** | | |
| Total revenue | **$ 257.7** | $ 233.4 | $ 213.4 |
| Net income | **56.5** | 40.7 | 37.6 |
| Net income per partnership unit | **0.170** | 0.123 | 0.113 |
| Funds from operations [1] | **114.4** | 113.4 | 100.7 |
| Distributions per partnership unit [1] | **0.069** | 0.066 | 0.065 |
| Total assets | **1,999.3** | 1,511.0 | 1,450.3 |
| Long-term debt, excluding current portion [2] | **810.5** | 825.2 | 800.9 |

1. Refer to "Non-GAAP Financial Measures" for further information concerning the non-GAAP financial measures used in this MD&A.
2. Deferred financing fees have been offset against long-term debt in our Financial Statements.

#### *Change in Property, Plant and Equipment*

| | Year ended | |
|---|---|---|
| | **2009** | 2008 |
| | **(in millions of dollars)** | |
| Opening balance | **$ 1,223.6** | $ 1,151.6 |
| Net additions | **462.9** | 140.6 |
| Depreciation and other | **(70.2)** | (68.6) |
| Change in accounting policy – site restoration costs | **108.4** | — |
| Reclassification of voided 500kV costs | **(36.7)** | — |
| Closing balance | **$ 1,688.0** | $ 1,223.6 |

| | 2009 Actual AUC | 2009 Actual Inventory | 2009 Actual CWIP | 2008 Actual AUC | 2008 Actual Inventory | 2008 Actual CWIP |
|---|---|---|---|---|---|---|
| | | | (in millions of dollars) | | | |
| **Opening balance** | $ 113.0 | $ 13.2 | $ 126.2 | $ 115.8 | $ 13.4 | $ 129.2 |
| Gross capital expenditures | 404.2 | — | 404.2 | 174.8 | — | 174.8 |
| Customer contributions related to expenditures | (70.5) | — | (70.5) | (32.9) | — | (32.9) |
| Additions to rate base | (204.3) | — | (204.3) | (176.6) | — | (176.6) |
| Customer contributions related to additions | 23.9 | — | 23.9 | 33.1 | — | 33.1 |
| Other adjustments | — | 2.7 | 2.7 | (1.2) | (0.2) | (1.4) |
| **Ending Balance** | $ 266.3 | $ 15.9 | $ 282.2 | $ 113.0 | $ 13.2 | $ 126.2 |
| **Mid-Year CWIP balance** | | | $ 204.2 | | | $ 127.7 |
| Regulated return on equity | | | 9.00% | | | 8.75% |
| Regulated common equity ratio | | | 36.00% | | | 33.00% |
| Regulated cost of debt | | | 5.5778% | | | 5.7800% |
| Regulated debt ratio | | | 64.00% | | | 67.00% |
| AFUDC equity | | | $ 6.6 | | | $ 3.7 |
| AFUDC debt | | | 7.3 | | | 4.9 |
| Other | | | — | | | (2.8) |
| Total | | | $ 13.9 | | | $ 5.8 |
| Weighted average cost of capital | | | 6.81% | | | 6.76% |

## Financial Position

The following table discusses significant changes in our balance sheet during 2009. Our financial statements include more detailed information regarding the changes in our property, plant and equipment.

| | Increase/(Decrease) ($ Millions) | Explanation |
|---|---|---|
| Property, plant and equipment | $ 464.4 | Prior to January 1, 2009, we netted our provision for future removal and site restoration against property plant and equipment. On January 1, 2009, we reclassified this provision as a liability on our balance sheet and increased the net book value of our property, plant and equipment by $145.4 million. As at June 30, 2009, we increased our estimate of asset retirement obligations by $86.6 million and increased the net book value of our property plant and equipment by the same amount. During the year ended December 31, 2009, we incurred construction costs for directly assigned transmission projects and capital replacement and upgrade costs on our existing facilities. |
| Accounts payable and accrued liabilities | 77.5 | Our accounts payable and accrued liabilities increased primarily due to higher capital construction activity. |

| | Increase/(Decrease) ($ Millions) | Explanation |
|---|---|---|
| Regulatory liabilities, long-term | 103.7 | On January 1, 2009, we reclassified our provision for future removal and site restoration from property, plant and equipment[1]. We also reclassified long-term regulatory liabilities into current. |
| Asset retirement obligations | 126.1 | As at June 30, 2009, we increased our estimate of asset retirement obligations by $86.6 million.[2] As well, capital additions for 2009 resulted in an increase of $33.8 million. |
| Partners' capital | 140.5 | We received equity investments of $140.5 million from AILP. |

[1] Please refer to note 3d of the financial statements for the year ended December 31, 2009.
[2] Please refer to note 4 of the financial statements for the year ended December 31, 2009.

## Operating Results for the Fourth Quarter and Year Ended December 31, 2009

***Revenues***

| | **2009** | 2008 | 2007 |
|---|---|---|---|
| | | **(in millions of dollars)** | |
| For the year ended December 31, | **$ 257.7** | $ 233.4 | $ 213.4 |
| For the three months ended December 31, | **$ 76.3** | $ 59.6 | $ 52.0 |

***Approved return on equity***

| | For the year ended December 31, | | |
|---|---|---|---|
| | **2009** | 2008 | 2007 |
| | | **(Percent)** | |
| | **9.00%** | 8.75% | 8.51% |

Our tariff revenues for 2009 reflect the impact of the 2009-10 GTA Decision and the 2009 GCOC Decision, both of which were released during the fourth quarter of 2009. Our tariff revenue in the fourth quarter and for the year of 2009 was greater than comparable periods in 2008 due to the impact of both the 2009-10 GTA Decision and 2009 GCOC Decision. The 2009-10 GTA Decision increased our revenues to reflect our forecast costs of providing service. The 2009 GCOC decision increased our approved rate of return on common equity from 8.75% to 9.00% for 2009 and 2010 and also increased our regulated equity ratio from 33% to 36%. We provide more details regarding these two decisions in this MD&A in the "Revenue Requirements" section.

We earn an increasing proportion of our revenues through the allowance for funds used during construction (AFUDC), which we capitalize to assets under construction. Due to the significant increase in our construction activity during 2009 and the 2009 GCOC Decision, our revenue from AFUDC equity increased by $4.1 million for 2009 and $3.2 million for the quarter, when compared to the same periods in 2008. The portion of AFUDC attributable to debt is offset against our interest expenses.

Our revenue in the fourth quarter and for the year of 2008 was higher than comparable periods of 2007 for similar reasons.

***Net income***

| | **2009** | 2008 | 2007 |
|---|---|---|---|
| | | **(in millions of dollars)** | |
| For the year ended December 31, | **$ 56.5** | $ 40.7 | $ 37.6 |
| For the three months ended December 31, | **$ 21.7** | $ 8.5 | $ 8.0 |

During 2009, we earned net income of $56.5 million, an increase of $15.8 million compared to the same period last year, primarily due to significantly higher investments in transmission facilities, the impact of the 2009 GCOC Decision, and gains on disposals of assets resulting from expropriations. For the fourth quarter of 2009, our net income of $21.7 million was $13.2 million higher than last year due to higher investment and the impact of both the 2009 GTA and GCOC decisions, which were received during the quarter and applied retroactively to the beginning of the year.

Similarly, our net income in the fourth quarter and for the year of 2008 was higher than comparable periods in 2007 due to a higher investment and return on our regulatory rate base.

### *Earnings before interest, taxes, depreciation and amortization (EBITDA)*

| | **2009** | 2008 | 2007 |
|---|---|---|---|
| | | **(in millions of dollars)** | |
| For the year ended December 31, | **$ 180.1** | $ 159.4 | $ 147.6 |
| For the three months ended December 31, | **$ 55.5** | $ 40.7 | $ 38.0 |

During 2009, our EBITDA totalled $180.1 million, an increase of $20.7 million compared with 2008. On a quarterly basis, our EBITDA of $55.5 million was $14.8 million higher than last year. The reasons for these increases are similar to those for changes in our net income for the same periods. Please refer to "Non-GAAP Financial Measures" for more information about how we calculate EBITDA.

Our 2008 EBITDA in the fourth quarter and for the year surpassed our 2007 EBITDA for comparable periods for the same reasons.

### *Operating expenses, including property taxes*

| | **2009** | 2008 | 2007 |
|---|---|---|---|
| | | **(in millions of dollars)** | |
| For the year ended December 31, | **$ 88.6** | $ 78.1 | $ 70.0 |
| For the three months ended December 31, | **$ 22.4** | $ 18.1 | $ 15.3 |

Our operating expenses include salaries and wages, contracted manpower, general and administration costs, property taxes, and insurance. During 2009, our operating expenses increased by $10.5 million ($4.3 million for the quarter) compared with the same period last year, of which $3.8 million relates to one-time capital construction services provided to ATCO Electric. Net of the ATCO Electric costs, the remaining increases are primarily due to additional manpower, wage increases, general inflation and other costs related to our continued growth.

2008 operating expenses in the fourth quarter and for the year were higher than comparable periods in 2007 for similar reasons.

### *Depreciation and accretion*

| | **2009** | 2008 | 2007 |
|---|---|---|---|
| | | **(in millions of dollars)** | |
| For the year ended December 31, | **$ 79.2** | $ 74.5 | $ 67.9 |
| For the three months ended December 31, | **$ 22.0** | $ 20.9 | $ 18.6 |

We calculate depreciation on a straight-line basis using various rates ranging from 1.73% to 20.00% which are approved by the AUC. Compared with the same periods in 2008, depreciation for the quarter and year to date have increased due to capital projects that have recently been completed and added to our regulatory rate base.

2008 depreciation in the fourth quarter and for the year was higher than comparable periods in 2007 also due to a greater number of capital projects completed and added to rate base.

### *Interest and amortization of deferred financing fees*

| | **2009** | 2008 | 2007 |
|---|---|---|---|
| | | **(in millions of dollars)** | |
| For the year ended December 31, | **$ 44.4** | $ 44.2 | $ 42.1 |
| For the three months ended December 31, | **$ 11.9** | $ 11.3 | $ 11.2 |

Our interest expense for the quarter and year to date was comparable to the same periods last year. Although our total long-term debt has increased from the comparable periods, interest rates on our money market debt decreased significantly from 2008 levels. We issued $100.0 million of medium term notes in May 2009 to reduce our money market debt and restore our liquidity under our bank credit facilities. We have adjusted our revenues to offset the net income impact of the interest costs related to our medium term notes, consistent with previous general tariff application decisions under which the AUC approved deferral account treatment for interest costs related to our medium term notes.

Our interest expense increased by $2.0 million in 2008 compared to 2007, primarily due to the refinancing of our maturing long-term debt and additional borrowings of $24.3 million used to fund our ongoing capital expenditure programs. The increase was partially offset by lower interest rates on money market debt. Interest expense for the fourth quarter in 2008 was comparable to the fourth quarter in 2007.

## Summary of Quarterly Financial Information

| Quarter ended | Total revenue ($millions) | Net income ($millions) | Units outstanding (millions) | Net Income per unit ($/unit) |
|---|---|---|---|---|
| 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 |
| December 31, 2007 | 52.0 | 8.0 | 331.9 | 0.024 |
| September 30, 2007 | 54.7 | 10.0 | 331.9 | 0.030 |
| June 30, 2007 | 52.9 | 8.3 | 331.9 | 0.025 |
| March 31, 2007 | 53.9 | 11.2 | 331.9 | 0.033 |

# Environment, Health and Safety

## The Environment

We are committed to meet all environmental regulatory requirements and to implement best environment management practices. The significant increase in capital projects during 2009 required a corresponding increase in related environment assessment work. We continue to add personnel to our environment team, not only to oversee the environmental aspects of capital projects, but also to further mitigate the impact of our continuing operations on the environment. During 2009, some of these initiatives include:

- Environmental consultants are conducting comprehensive environmental assessments to support the development of our major transmission line projects;
- Environmental pre-screenings are being conducted for all standard capital projects;
- The environmental model class screening report, which governs the maintenance of our transmission lines in Banff National Park, was re-declared for a 10 year period;
- We planned measures to achieve compliance with new Federal PCB legislation; and
- We were the first Canadian utility to develop an Avian Protection Plan.

Although primarily regulated at the provincial level, federal agencies and local managing authorities also share jurisdiction over environmental matters. As a result, all aspects of our operations are subject to one or more levels of environmental regulation.

Federal legislation is the primary regulating authority in situations involving federal lands (e.g., National Parks, First Nations' lands), trans-boundary environmental impacts (*e.g.*, ozone depleting substances), or issues of national concern (e.g., hazardous substances such as PCBs). Provincial legislation and regulations apply to all aspects of our transmission system operation and maintenance.

In 2009, we spent approximately $8.3 million (2008 - $2.5 million) to meet or exceed environmental protection requirements, including environmental assessments for new 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 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.

In 2008, our board of directors established a separate environmental, health and safety committee to enhance oversight of our environmental, health and safety matters. This committee 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.

### *Environmental management system*

We use our environmental management system to assess and manage environmental risks associated with transmission operation and maintenance activities. This environmental management system establishes operational standards, procedures and guidelines which are designed to meet or exceed applicable compliance thresholds. We believe that in operating our business we meet applicable environmental and safety regulations and approvals.

Under our environmental management system, we identify, manage and mitigate key environmental risks and maintain regulatory compliance through our established operational standards and policies. We support and enhance the effectiveness of our system through appropriate reporting, record keeping, training and auditing processes. Although not certified under ISO 14001, we believe that our system is patterned on and consistent with this international standard for environmental management systems.

Our environmental management system is organized into five broad programs, which are more fully described in our annual information form:

- chemical and spill management;
- land management;
- rights-of-way management;
- treated wood management; and
- waste management

### *Electric and magnetic fields*

We recognize that some people are concerned about electric and magnetic fields (EMF), which are produced by all electrical devices, including transmission facilities. We treat those concerns very seriously. We are aware of considerable scientific research about potential public health risks associated with exposure to EMF. After conducting studies and reviews on this issue over the past 30 years, many agencies have not concluded that exposure to EMF from transmission lines causes long-term adverse effects on human, plant or animal health. We recognize that EMF exposure is a very complex issue and we continue to monitor any new developments with regard to EMF.

We continuously monitor research on this issue and provide accurate and up-to-date information, including measurements, to the public as requested. During 2009, 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. As previously noted, our safety performance during 2009 was significantly lower than over the preceding five year period. While our safety performance is still comparable with the historical safety results of our peers, we are taking immediate and significant measures to bring our safety performance back to top quartile rankings. We have launched a safety management initiative that encompasses every aspect of our safety systems – from our safety practices and procedures to our performance management skills and leadership. Key activities already underway pursuant to this initiative include:

- Conducting a comprehensive set of stakeholder engagement sessions to assist in diagnosing the root causes of the deterioration in our performance;
- Identifying, developing and implementing short term safety improvement changes designed to stabilize and reverse the negative trend of our safety performance; and
- Identifying, developing and implementing long term safety improvement changes using our business process methodology to ensure success and sustainability of the implemented changes.

Here are some of the positive practices we have implemented to enhance the health and safety of our people:

- Continuously assessing safety practices to address changing regulations, new hazards in the workplace, changes in work methods, new equipment and tools;
- Annual safety training for all field employees;
- Engaging in a joint utility safety team public safety awareness campaign called, "*Where's the Line*";
- Continuing evaluation of our contractor safety management program with a focus on:
    - Ensuring contracting companies are pre-qualified;
    - Setting clear expectations for safety and quality performance standards; and
    - Performing on the job monitoring of safety practices, work methods and safety performance;
- Requiring workers in energized facilities to hold safety certification, a four-tier certification rating system.

# Insurance and Risk Factors

## Insurance

We believe that our insurance program is adequate and prudent for our business risks. Our 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. The Liability Protection Regulation limits our liability to direct loss or damage arising from our negligence, wilful misconduct or breach of contract. Direct loss or damage does not include loss of profits, loss of revenue, loss of production, loss of earnings, loss of contract or other indirect special or consequential loss or damage. During our general tariff applications, the AUC reviews the scope and costs of our insurance program. We can apply to the AUC to recover uninsured losses greater than $100,000 through our self-insurance reserve, which is funded through transmission tariffs.

We do not carry commercial insurance against all of our business risks. In some cases, insurance premiums are too expensive or the coverage is not available at all. For example, we do not purchase insurance coverage against loss or damage to transmission lines, towers, poles, or physical damage to certain owned vehicles. Although we maintain liability insurance, including pollution liability, such insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions. Some of our insurance policies exclude coverage for damages resulting from environmental contamination.

## Risk Factors and Uncertainties

Our transmission business is subject to a variety of risks and uncertainties, including those described below. 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.

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.

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*

We are regulated as a transmission facility owner in Alberta and many aspects of our business require approvals from the AUC. 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 be subject to 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 securities.

Project risks can also translate into actual project costs being in excess of project cost estimates. We are dependent upon AUC decisions for our 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. Costs 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. DBRS has stated that its "A" rating of our securities incorporates the assumption that the AUC would, if required, provide us with the regulatory support to prevent our credit metrics from declining below acceptable levels throughout the capital expenditure program.

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 AUC. 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 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 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. (AILP) 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. Current global financial conditions and recent market events have been characterized by increased volatility and the resulting tightening of credit has reduced 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 55% of our employees are members of one of two labour unions, the United Utility Workers Association (UUWA) or the International Brotherhood of Electrical Workers (IBEW), which have entered into collective bargaining agreements with our general partner. The provisions of these collective agreements affect the flexibility and efficiency of our business. Both collective agreements expired on December 31, 2009 and we are currently negotiating their renewal. Our relationships with these labour unions are considered to be satisfactory; however, there can be no assurance that current relations will remain unchanged in negotiations or mediation, or that the terms of the collective bargaining agreements will be renewed on acceptable terms. If that occurs, we could face the risks of service interruptions arising from labour disputes or increased labour costs. The inability to recover any significant difference between forecast and actual labour costs could adversely affect our financial condition and results of our operations.

### *Availability of people*

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

### *Environment, health and safety*

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

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

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

Electricity transmission facilities may also cause wildfires as a result of equipment failure, trees falling on a transmission line, or lighting 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, we expect that we may become subject to competition for the assignment of a portion of new transmission facility projects, as contemplated under the recently enacted the *Electric Statutes Amendment Act, 2009*. 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.

## Legal Proceedings

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

On June 5, 2009, we were served with an action alleging that the plaintiff and we had concluded a binding agreement to sell certain lands in Calgary, Alberta to the plaintiff. The final outcome of this matter is uncertain and there can be no assurance that this matter will be resolved in our favour. Even if this matter is not resolved in our favour, we do not expect the outcome to have a material adverse impact on our financial position, results of operations or liquidity.

## Accounting Policy and Related Disclosures

### Changes in Accounting Policies

### Changes Impacting the 2009 Financial Statements

***Financial instruments***
Effective September 30, 2009 the Partnership adopted the amendments to CICA Handbook Section 3862, Financial Instruments – Disclosure. The amendments require an entity to disclose a quantitative maturity analysis for financial liabilities that shows the remaining contractual maturities and establish a hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The three levels of the fair value hierarchy are:

- Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities (level 1).
- Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability (level 2).

- Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement (level 3).

***Goodwill and intangible assets***

In February 2008, the CICA issued Section 3064, *Goodwill and intangible assets*, replacing Section 3062, *Goodwill and other intangible assets* and Section 3450, *Research and development costs*. Various changes have also been made to other sections of the CICA Handbook for consistency purposes. The Partnership adopted the new standards for its fiscal year beginning January 1, 2009. Section 3064 establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062, and as a result, there is no impact on the Partnership's financial statements.

***Accounting for rate regulated operations***

Beginning on January 1, 2009, Section 1100 of the CICA Handbook, *Generally Accepted Accounting Principles* was amended to remove a temporary exemption pertaining to the recognition of assets and liabilities arising from rate regulation. In addition, effective the same date, Section 3465 of the CICA Handbook, *Income Taxes* was also amended. There are no changes to the Partnership's financial statements other than the prospective reclassification at January 1, 2009 of $145.4 million from property, plant and equipment to the provision for future removal and site restoration which is included in regulatory liabilities on the balance sheet. There is no impact on the Partnership's net income as a result of this change.

## Changes That May Impact Our Financial Statements In The Future

***International financial reporting standards (IFRS)***

On February 13, 2008, the CICA Accounting Standards Board confirmed that the conversion to IFRS from Canadian GAAP will be required for publicly accountable profit-oriented enterprises for both interim and annual financial statements beginning on or after January 1, 2011.

In Staff Notice 52-320, Disclosure of Expected Changes in Accounting Policies relating to Changeover to IFRS, the Canadian Securities Administrators noted the conversion to IFRS represents a change due to the implementation of new accounting standards. As a result, the transition from current Canadian GAAP to IFRS is a significant undertaking that may materially affect our reported financial position and results of operations. The Notice 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 second quarter of 2008 as well as the following update:

We have established an internal steering committee for our adoption of IFRS, which oversees our project team and working groups in carrying out the detailed tasks involved in the conversion project. The project team and working groups provide position papers and regular updates to our senior management, steering committee, Audit Committee and external auditors. We continue to provide employee education sessions to increase knowledge and awareness of IFRS and its impacts.

We actively participate in various industry peer groups, including the Canadian Electricity Association (CEA). We are also reviewing discussion papers, exposure drafts and standards released by the International Accounting Standards Board (IASB) and the International Financial Reporting Interpretations Committee. We will continue to assess the impact of the proposed standards on our financial statements and disclosure as additional information becomes available.

As discussed in detail previously, 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, including the detailed assessment of the impact of IFRS on our accounting processes, financial statements, treasury operations, regulatory systems and processes and operating systems and processes. The detailed assessment included analysis of the issues raised in Phase 1 as well as of our proposed recommendations to resolve these issues.

At this stage, we are unable to determine the impact that IFRS will have on our financial position and results of operations. A major factor in determining the extent of the impact that IFRS will have on us is the final outcome of the IASB's current project to develop a standard to provide guidance for accounting for rate-regulated activities. The IASB issued an exposure draft on July 23, 2009 outlining proposed standards for the recognition, measurement, presentation and disclosure of rate-regulated activities. We currently meet the scope requirements of the exposure draft, and will be eligible to recognize regulatory assets and regulatory liabilities in accordance with the guidance.

In our first quarter 2009 MD&A, prior to the issuance of the exposure draft, we identified certain standards that may have a significant effect on our financial statements and our accounting systems upon transition to IFRS. For example, we identified that we may need to establish a separate general ledger for IFRS reporting purposes, depending on the guidance in the final version of the rate-regulated activities standard. In addition, our current treatment of AFUDC and other regulatory amounts may be allowed to continue under IFRS. If so, the impact of conversion to IFRS on property, plant and equipment and regulated assets and regulated liabilities may be minimal.

Comment letters on the exposure draft were due on November 20, 2009. We submitted a joint letter with the CEA, Canadian Gas Association and Canadian Energy Pipeline Association, and also submitted an independent letter, both strongly supporting the exposure draft. The IASB was expected to issue a final standard in the first half of 2010. However, we recently received information that the IASB staff has determined that they will not be taking feedback on the proposed standard to the IASB in January 2010 as originally scheduled. Instead, the staff is expected to present an analysis of the responses at the February meeting. The delay is due to the large number of responses received, as well as the great diversity in opinions and comments on virtually every critical aspect of the proposed standard. The presentation at the February meeting may also include discussion on the options for the next steps for the project.

Potential next steps include:

- Move forward with the standard, but with significant changes to the Exposure Draft
- More forward by amending current IFRSs, rather than issuing a separate standard
- Move forward, but only with a disclosure standard
- Not issue additional guidance

Significant matters that the IASB expects to discuss in determining the next steps include how the asset/liability Framework definitions are met and the scope of the standard. The IASB conducts monthly meetings where they will discuss this project and we will continue to monitor these discussions to gain a sense of what the final standard will look like, as well as the timing of implementation. Our focus from a decision making prospective will be the February and March 2010 meetings of the IASB.

The timing of finalization of our information system strategy in 2010 is dependent on the decision made by the IASB as to how it intends to move forward with the proposed standard. During the last quarter of 2009, we implemented information system changes for areas that will be affected upon transition to IFRS but will not be affected by the outcome of the final rate-regulated activities standard. We will decide upon our strategy for implementation of the remaining elements of our system by the end of the first quarter of 2010, when we expect to have a clearer idea of the direction to be taken by the IASB.

We have identified the following differences between our current accounting policies and those we expect to apply under IFRS:

- IAS 38, *Intangible assets* - computer software and land rights will be reclassified from property, plant and equipment (PP&E) and into intangible assets. This change will be a reclassification only and is not expected to have an impact on our financial position or results of operations.
- IAS 36, *Impairment of Assets* - requires a before tax discount rate to be used in the impairment testing of goodwill. It is not anticipated that using the pre-tax discount rate will result in an impairment of goodwill.
- IFRIC 18, *Transfers of Assets from Customers* - requires cash contributions from customers to be recognized as revenue over the useful life of the associated asset that is acquired or constructed. Under IFRS, the associated assets will be recognized at cost. Currently under Canadian GAAP, the cash contribution is offset against the cost of the associated asset and then amortized over the life of the asset as an offset to depreciation expense. Therefore, under IFRS, the cost of PP&E will be higher by the amount of cash contributions when expended and depreciation expense will be higher. This change will be a reclassification only and is not expected to have an impact on our financial position or results of operations.

If the final rate-regulated activities standard follows the proposals in the exposure draft, we expect to see the following accounting policy changes:

- Regulatory assets and regulatory liabilities will be measured at their expected present value (EPV). The EPV calculation will incorporate an estimate of future cash flows, the probability of occurrence and related discount and risk factors.
- Gains and losses on retirements and/or disposal of PP&E will be included in the statement of comprehensive income instead of the current treatment of being offset against PP&E.
- We will consider whether, on a net basis our regulatory assets and liabilities have been impaired.

The exposure draft proposes to allow us to include, in the cost of self-constructed PP&E or internally generated intangible assets, all amounts included by the regulator even if those amounts would not be included in the assets’ cost in accordance with other IFRSs. The exposure draft also proposes enhanced disclosure for rate-regulated activities, assets and liabilities. We anticipate electing the following IFRS 1 exemptions at the date of transition:

- Business combinations
- Employee benefits
- Potential PP&E and intangible asset exemption for entities with rate-regulated activities (included in the exposure draft)

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. We will update the IFRS changeover plan to reflect any new issues that have an impact.

## 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 fair value of residual cash flows;
- The allowance for doubtful accounts;
- The estimated useful lives of assets;

- The recoverability of intangible assets including estimates of future costs to retire physical assets, such as our asset retirement obligations and site restoration costs, or the recoverability of costs associated with the direct assigned capital deferral account for projects that have been delayed in the regulatory process;
- The recoverability of intangible assets with indefinite lives, such as goodwill;
- Future income tax liability;
- The accruals for 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 in December 2009. We examined the business and regulatory environment, the ownership structure, the 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 fair value determination in December 2008.

### *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. We discuss critical accounting estimates related to the Genesee to Langdon voided 500k V Project Costs in the "Revenue Requirements" section of this MD&A.

### *Asset retirement obligations*

We recognize the fair value of liabilities 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 to earnings in a systematic manner over the useful lives of the assets. We recognize our statutory, contractual and legal obligations for asset retirements. The discounted present value of the liability accretes over time for changes in the present value, with the accretion expense included in depreciation.

Asset retirement obligations are legal obligations that may apply to both the retirement of an entire transmission line, or to parts of the larger system. Interim retirement obligations are recognized in the latter circumstance when a component is retired prior to the retirement of the entire transmission line. Asset retirement obligations are recorded as a liability, with a corresponding increase to property, plant and equipment.

Since we determined that there are no legal obligations associated with the interim retirement of electric substations and telecom sites, interim asset retirement obligations for these sites have not been recognized. While there will be future retirement obligations associated with the final retirement of these assets, we have not recognized any obligation at this time because the date of final removal cannot be reasonably determined.

### *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.

### 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 SNC-Lavalin Inc. (SNC-Lavalin) provides engineering, procurement and construction management services for our directly assigned capital projects. SNC-Lavalin provides these services to us through its subsidiary, SNC-Lavalin ATP Inc. (SNC-ATP). The AUC has reviewed and approved the terms and conditions of this contract in Decision 2003-061 and subsequent decisions, including Decision 2009-051 issued on October 2, 2009. On a year to date basis, we have paid SNC-ATP $200.1 million for construction related services during 2009 (2008 - $54.4 million). During the fourth quarter of 2009, we paid SNC-ATP $92.2. million compared to $15.9 million during the fourth quarter of 2008. On December 31, 2009, our accounts payable and accrued liabilities included $83.2 million owing to SNC-ATP under this agreement, compared to $17.2 million at December 31, 2008.

As at December 31, 2009, 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 8.5%.

## 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 changes in the legislative and operating framework for Alberta's electricity market which are adverse to our business (see "*ALBERTA'S ELECTRICITY MARKET STRUCTURE*" and "*TRANSMISSION SYSTEM PLANNING AND DEVELOPMENT – Provincial Energy Strategy*" and "*TRANSMISSION SYSTEM PLANNING AND DEVELOPMENT – System Expansion Plans*" in our Annual Information Form (AIF) or the Material Change Report filed on December 31, 2009, for example);
- 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 "*THE TRANSMISSION BUSINESS - Revenue Tariffs*" and "*ALBERTA'S ELECTRICITY MARKET STRUCTURE*" in our AIF), or the Material Change Report filed on December 31, 2009, for example);
- Approved rate-of-return and deemed capital structures for our transmission business which are sufficient to foster a stable investment climate (see "*THE TRANSMISSION BUSINESS - Revenue Tariffs*" and "*ALBERTA'S ELECTRICITY MARKET STRUCTURE*" in our AIF) or the Material Change Report filed on December 31, 2009, for example);
- 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 19, 2010. 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.

## Additional Information

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

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