2009 FINANCIAL REPORT

ALTALINK

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MANAGEMENT'S DISCUSSION & ANALYSIS

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 12-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 69 kV to 500 kV 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 reusing 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 GREENJACKET™, 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 12-month period.

2. System Availability Interruption Duration Index is the average number of interruption hours per delivery point during a 12-month period.

3. Benchmark statistics from the CEA 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 CEA 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

(in millions of dollars)	2010 Forecast	2009 Estimate
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 500 kV project costs, which are discussed below, our revenues for the 12-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		
(in millions of dollars)	2010	2009	2008
	Compliance Filing [1]	Compliance Filing [1]	Approved [2]
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
Southwest 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 500 kV 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.

Southwest 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 Southwest 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 Southwest 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 10 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 10 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 240 kV 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.

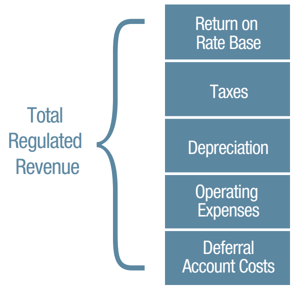
Transmission Tariffs

Overview

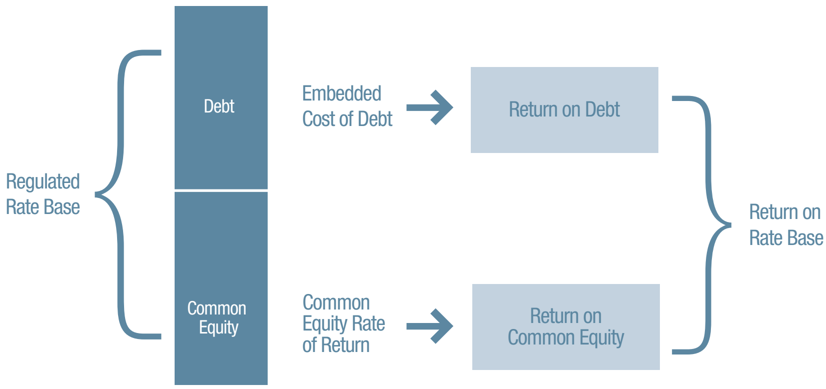
The AESO pays transmission tariffs to us in equal monthly installments, without regard to either the price or volume of electricity transmitted through our transmission system.

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.

(in millions of dollars)	December 31, 2009	December 31, 2008
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 12-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, 20 working days following the end of the previous month. Because two payments were outstanding on December 31, 2007, we received 13 monthly payments from the AESO during 2008, compared with 12 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		
(in millions of dollars except per unit amounts)	**December 31, 2009**	December 31, 2008	December 31, 2007
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	
(in millions of dollars)	**December 31, 2009**	December 31, 2008
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 500 kV costs	**(36.7)**	—
Closing balance	**$ 1,688.0**	$ 1,223.6

(in millions of dollars)	2009 Actual AUC	2009 Actual Inventory	2009 Actual CWIP	2008 Actual AUC	2008 Actual Inventory	2008 Actual CWIP
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

(in millions of dollars)	2009	2008	2007
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
	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

(in millions of dollars)	2009	2008	2007
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)

(in millions of dollars)	2009	2008	2007
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

(in millions of dollars)	2009	2008	2007
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

(in millions of dollars)	2009	2008	2007
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

(in millions of dollars)	2009	2008	2007
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 redeclared 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), transboundary 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; and
- 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, willful 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, 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 clean up 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 *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 500 kV 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 rate making 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 11 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 10-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.

MANAGEMENT'S REPORT

The financial statements of AltaLink, L.P. were prepared by management in accordance with Canadian generally accepted accounting principles. The financial and operating information presented in this annual report is consistent with that shown in the financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of non-management Directors, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the financial statements.

(signed)
"Scott Thon"
President and Chief Executive Officer

(signed)
"Joseph Bronneberg"
Chief Financial Officer

January 29, 2010
Calgary, Canada

TO THE PARTNERS OF ALTALINK, L.P.

We have audited the balance sheets of AltaLink, L.P. as at December 31, 2009 and 2008 and the statements of income, comprehensive income and retained earnings, changes in partners' equity and cash flows for the years then ended. These financial statements are the responsibility of AltaLink, L.P.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of AltaLink, L.P. as at December 31, 2009 and 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants

January 29, 2010
Calgary, Alberta

BALANCE SHEETS

(in thousands of dollars)	As at December 31, 2009	December 31, 2008
ASSETS		
Current		
Cash and cash equivalents	$ 8,319	$ —
Accounts receivable *[note 12]*	24,534	20,991
Prepaid expenses and deposits	7,646	11,476
Regulatory assets *[note 7]*	1,469	516
	41,968	32,983
Property, plant and equipment *[notes 3d and 8]*	1,687,990	1,223,606
Contributions in advance of construction	50,620	39,751
Operating and maintenance charges in advance	12,222	7,733
Regulatory assets, long-term *[note 7]*	2,378	2,797
Accrued benefit pension asset *[note 9]*	2,042	2,079
Goodwill	202,066	202,066
	$ 1,999,286	$ 1,511,015
LIABILITIES AND PARTNERS' EQUITY		
Current		
Accounts payable and accrued liabilities *[note 12]*	$ 120,430	$ 42,965
Other liabilities	1,753	1,319
Regulatory liabilities *[note 7]*	11,073	6,759
Current portion of long-term debt *[note 10]*	376	142
	133,632	51,185
Accrued employment benefits liabilities *[note 9]*	3,034	2,442
Other liabilities, long-term	3,416	3,242
Contributions in advance of construction liability	50,620	39,751
Operating and maintenance charges in advance liability	12,222	7,733
Regulatory liabilities, long-term *[note 7]*	124,445	20,774
Asset retirement obligations *[note 11]*	186,305	60,181
Long-term debt *[note 10]*	804,107	818,388
	1,317,781	1,003,696
Commitments and contingencies *[notes 18 and 19]*		
Partners' equity		
Partners' capital *[note 20]*	549,036	408,536
Retained earnings	132,469	98,783
	681,505	507,319
	$ 1,999,286	$ 1,511,015

See accompanying notes to the financial statements

Approved on behalf of the Board of Directors

(signed)
"David Tuer"
Director

(signed)
"Patricia Nelson"
Director

STATEMENTS OF INCOME, COMPREHENSIVE INCOME AND RETAINED EARNINGS

(in thousands of dollars)	Year ended December 31, 2009	December 31, 2008
REVENUE		
Transmission tariff *[note 13]*	$ 236,134	$ 222,228
Miscellaneous revenue *[note 14]*	14,927	8,656
Allowance for equity funds used during construction	6,597	2,472
	257,658	233,356
EXPENSES		
Operating *[note 12]*	72,155	61,319
Property taxes	16,475	16,753
Depreciation and accretion	79,150	74,487
	167,780	152,559
	89,878	80,797
Interest and amortization of deferred financing fee *[notes 10e and 12]*	(44,422)	(44,169)
Allowance for debt funds used during construction	7,281	3,278
	52,737	39,906
Gains on disposals of assets	3,792	822
Net and comprehensive income for the year	$ 56,529	$ 40,728
Retained earnings, beginning of year	$ 98,783	$ 80,055
Distributions	(22,843)	(22,000)
Net income for the year	56,529	40,728
Retained earnings, end of year	$ 132,469	$ 98,783

See accompanying notes to the financial statements

STATEMENTS OF CHANGES IN PARTNERS' EQUITY

(in thousands)	Units	Limited Partner	General Partner	Total
Balance at December 31, 2007	**331,904**	**$ 488,549**	**$ 42**	**$ 488,591**
Net income for the year	—	40,724	4	40,728
Distributions	—	(21,998)	(2)	(22,000)
Balance at December 31, 2008	**331,904**	**507,275**	**44**	**507,319**
Net income for the year	—	56,523	6	56,529
Distributions	—	(22,841)	(2)	(22,843)
Equity investment received *[note 20]*	—	140,500	—	140,500
Balance at December 31, 2009	**331,904**	**$ 681,457**	**$ 48**	**$ 681,505**

See accompanying notes to the financial statements

STATEMENTS OF CASH FLOWS

(in thousands of dollars)	Year ended December 31, 2009	December 31, 2008
OPERATING ACTIVITIES		
Net income for the year	$ 56,529	$ 40,728
Items not involving cash:		
Depreciation	70,245	71,524
Amortization of deferred financing fees	1,604	1,697
Accretion	8,905	2,963
Allowance for funds used during construction	(13,878)	(5,750)
Gains on disposals of assets	(3,792)	(822)
Change in regulatory assets and liabilities	(4,752)	4,333
Change in other non-cash items	803	1,352
Asset retirement obligations settled	(1,236)	(2,651)
Funds generated from operations	114,428	113,374
Change in non-cash working capital items *[note 15]*	9,656	24,984
Cash provided by operating activities	124,084	138,358
INVESTING ACTIVITIES		
Capital expenditures *[note 8]*	(364,541)	(168,758)
Change in non-cash working capital items *[note 15]*	71,890	(5,452)
Use of customer contributions related to capital expenditures *[note 8]*	70,552	32,883
Proceeds from disposals of assets	3,841	848
Cash used in investing activities	(218,258)	(140,479)
FINANCING ACTIVITIES		
Senior debt issued	102,840	100,142
Senior debt repaid	(248)	(100,135)
Net change in commercial paper and bank credit	(117,080)	24,322
Distributions	(22,843)	(22,000)
Equity investment received	140,500	—
Net change in other financing activities *[note 16]*	(676)	(208)
Cash provided by financing activities	102,493	2,121
Net increase in cash and cash equivalents	8,319	—
Cash and cash equivalents, beginning of year	—	—
Cash and cash equivalents, end of year	$ 8,319	$ —
Cash interest paid during the year	$ 45,091	$ 42,594

See accompanying notes to the financial statements

NOTES TO FINANCIAL STATEMENTS

1. Nature of Operations

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

The Partnership is a regulated electric utility under the jurisdiction of the Alberta Utilities Commission (AUC). Effective January 1, 2008, the AUC assumed responsibility from the Alberta 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 Partnership is indirectly owned by two limited partners. SNC-Lavalin Transmission Ltd. indirectly owns 76.915% of AltaLink, L.P. through subsidiaries, and Macquarie Transmission Alberta Ltd. owns the remaining 23.075%.

The Partnership is an electricity transmission facility owner, whose business is the ownership and operation of regulated electricity transmission facilities solely in the Province of Alberta. The Partnership also owns and operates Alberta's portion of the interconnection facilities which connect its network with the transmission system in British Columbia, and allow electricity to flow into and out of Alberta.

During the years ended December 31, 2009 and 2008, AltaLink operated in one primary reportable geographical and business segment, the ownership and operation of regulated electricity transmission facilities in the Province of Alberta. For the year ended December 31, 2009, approximately 94% *(Tariff Revenue and AFUDC Equity)* (December 31, 2008 – 96%) of the Partnership's revenue is from the Alberta Electrical System Operator (AESO).

2. Basis of Accounting

Management has prepared the Partnership's financial statements in accordance with Canadian generally accepted accounting principles (GAAP), including the accounting policies described in note 3(a) for the recognition and measurement of assets and liabilities arising from rate regulation. All amounts reported are in Canadian dollars unless otherwise stated.

These financial statements reflect the Partnership's financial position and results of operations and do not include all of the assets, liabilities, revenues and expenses of the partners.

3. Summary of Significant Accounting Policies

a) Regulation

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

The Partnership operates under cost of service regulation as prescribed by the AUC. Under the EUA, 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. Fair return is determined on the basis of return on rate base and allowance for funds used during construction (AFUDC) on construction work in progress (CWIP). The Partnership applies for tariff revenue based on forecast costs of service. Once the tariff is approved, it is not adjusted as a result of actual costs of service being different from that which was forecast, other than for certain prescribed costs, as explained further below.

The Partnership accounts for certain transactions using regulatory accounting when three criteria are met: (i) the rates for regulated services or products provided to customers are established by or are subject to approval by an independent, third-party regulator; (ii) the regulated rates are designed to recover the cost of providing the services or products; and (iii) in view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates are set at levels that will recover the cost that can be charged to and collected from customers.

Under regulatory accounting, the Partnership accounts for some transactions or events differently than it would in the absence of rate regulation. Through the regulatory process, certain expenses and credits are deferred as assets or liabilities on the balance sheet. Regulatory assets represent costs incurred in the current period or in prior periods that are expected to be recovered in future periods. Regulatory liabilities represent amounts collected which are either held as reserves for future use or are to be refunded in future periods. For information regarding the regulatory assets and liabilities recorded by the Partnership, see note 7 - *Regulatory Assets and Liabilities*.

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

b) Measurement Uncertainty

GAAP requires management to make estimates and assumptions that affect amounts reported in the financial statements and accompanying notes. Certain estimates are necessary since the regulatory environment the Partnership operates within often requires amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions, or other regulatory proceedings. Due to inherent uncertainty involved in making estimates, actual results reported in future periods could differ significantly from those estimates.

Significant estimates include: key economic assumptions used to determine the fair value of cash flows; the allowance for doubtful accounts; the allowance for obsolescence of materials and supplies; the estimated useful lives of assets; the recovery of intangible assets; estimates of future costs to retire physical assets; the recovery of costs associated with direct assigned projects; the valuation of intangible assets with indefinite lives, such as goodwill; the amount of future income tax liability; the accruals for accrued liabilities, payroll and other employee-related liabilities; certain actuarial and economic assumptions used in determining defined benefit pension costs, accrued pension benefit obligations and pension plan assets; and, the recovery and settlement of the regulated assets and liabilities.

c) Cash and Cash Equivalents

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

d) Property, Plant and Equipment

Property, plant and equipment are carried at cost, which includes direct labour, materials and allocated overheads, less depreciation. The Partnership capitalizes major replacements and upgrades to property, plant and equipment if these costs have been included in capital assets for regulatory purposes and are expected to be recovered within rates. The Partnership capitalizes an allowance for funds used during construction which represents the cost of debt and equity financing incurred during construction as approved by the AUC. AFUDC is a non-cash item that will be recovered in rates charged to customers over the service life of the assets, commencing with the assets' inclusion in the rate base.

Depreciation is calculated on a straight-line basis, based on depreciation studies prepared by the Partnership which have also been approved by the AUC for regulation of tariffs. The depreciation rates are based on the estimated useful lives of assets. For more information, see note 8 – *Property, Plant and Equipment*.

	Approved Rates	Weighted Average Rates for 2009
Lines	1.73% - 6.24%	3.34%
Substations	1.85% - 6.78%	4.96%
Buildings & equipment	2.71% - 20.00%	9.01%
Land & CWIP	Not subject to depreciation	—
Long-lived assets	See note 11	—
Customer contributions	3.35%	3.35%

Changes to depreciation rates are accounted for on a prospective basis. The rates are applied to the original historical capital costs, which are used for regulatory rate setting purposes and may be greater than those reflected in these financial statements. Non-emergency spare parts and long-term capital inventory items are included in the property, plant and equipment balance, but are not depreciated. These assets are valued at the lower of cost or net realizable value. Cost is determined on a moving average cost basis, other than for major equipment, which is determined on a specific item basis. For regulatory purposes, the net proceeds from the retirement or disposal of an asset in the normal course of business is reflected in accumulated depreciation. When a regulated asset is retired or disposed of in the normal course of business, there is no gain or loss recorded in income, other than for land. Any difference between the cost of the asset and the accumulated depreciation is charged to the accumulated depreciation account for that asset.

e) Contributions and Operating and Maintenance Charges in Advance of Construction

For certain projects, customers contribute their share of capital project costs in advance of construction. The Partnership is entitled to use these cash contributions to fund capital expenditures as construction progresses. The customers' shares of capital project costs are offset against the cost of property, plant and equipment and are amortized over the useful life of the assets.

In addition, certain customers are required to provide advance funding for future operating and maintenance costs of customer contributed assets. After these assets are put into service, the Partnership draws down these contributions to fund related operating and maintenance costs over the life of the related assets.

f) Deferred Financing Fees

Costs incurred to arrange debt financing are capitalized as deferred financing fees and are recorded as an offset to long-term debt. Deferred financing costs that are not expected to be recovered through rates are amortized using the effective interest rate method over the term of the related debt. Deferred financing fees that are expected to be recovered through transmission tariff rates are amortized using methods and rates approved by the AUC. The amortization of these charges is included as part of interest on debt.

g) Goodwill

Goodwill represents the excess of the purchase price over the fair value of the net identifiable assets of operations acquired. Goodwill is carried at initial cost less any write-down for impairment. In the last quarter of each fiscal year and as economic events dictate, management reviews the valuation of the goodwill, taking into consideration any events or circumstances which might have impaired the fair value.

Management performed a goodwill impairment test in December 2009 by examining the business and regulatory environment, current market conditions, the ownership structure, financing activities, credit ratings and interest rates. It also performed a discounted cash flow and net fair value analysis, which compared favourably to the carrying amount of goodwill. Management concluded that there have been no significant changes in circumstances since the fair value determination in December 2008 and that the carrying value of the goodwill has not been impaired.

h) Employee Future Benefit Plans

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

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

Cumulative net unamortized actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or fair value of plan assets at the beginning of the fiscal year and unamortized past service costs are amortized over the expected average remaining service lifetime of active employees receiving benefits under the plan.

When the recognition of a transfer of employees and employee related benefits gives rise to a curtailment and a settlement of obligations, the curtailment is accounted for prior to settlement.

The employee future pension expense is calculated under GAAP. However, under regulatory accounting principles, the final employee future benefit expense recognized in these financial statements is adjusted for amounts which will be recovered within rates (notes 7 – *Regulatory Assets and Liabilities* and 9 – *Employee Future Benefits Plans*).

i) Taxes

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

On October 31, 2006, the Minister of Finance (Canada) announced the Specified Investment Flow-Through (SIFT) Rules, which proposed changes to the manner in which certain partnerships are taxed. In management's opinion, the Partnership is not subject to the SIFT Rules, and no provision for such taxes has been made in the financial statements. On December 20, 2007, the Federal Minister of Finance announced proposed technical amendments, that align with the opinion of management, to ensure that only those structures targeted by the SIFT Rules will be subject to the SIFT regime. On March 12, 2009, the technical amendments received Royal Assent.

j) Foreign Currency Translation

The Partnership's functional currency is the Canadian dollar. Monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Non-monetary assets and liabilities are translated at exchange rates prevailing at the transaction date. Revenues and expenses are translated at the exchange rate prevailing on the date of the transaction except for depreciation and amortization, which are translated at the exchange rate prevailing when the related assets were acquired. Gains and losses on translation are reflected in income when incurred.

k) Revenue Recognition

Revenues from rate regulated operations are recognized on the accrual basis in accordance with revenue requirements approved by the AUC, and 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. Miscellaneous revenue includes, but is not limited to, services provided on a cost recovery basis to other utilities. A summary of miscellaneous revenue and its components is provided in note 14 – *Miscellaneous Revenue*.

l) Deferred Lease Inducements

Deferred lease inducements represent leasehold improvements paid for by the landlord. Deferred lease inducements are amortized on a straight-line basis over the periods of the leases, and the amortization is recorded as a reduction of rent expense. The unamortized balance in deferred lease inducements is included in “Other liabilities”.

m) Asset Retirement Obligations

The estimate of the fair value of liabilities for asset retirement obligations is recognized in the period they are incurred. A corresponding increase to the carrying amount of the related asset is recorded and depreciated over the life of the asset. The amount of the liability is subject to remeasurement at each reporting period and is accreted over the estimated time period until settlement of the obligation.

4. Changes in Significant Accounting Policies

Changes Affecting the Current Year Financial Statements

a) 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).

b) 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 (December 31, 2009 - $108.4 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.

c) 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.

5. Financial Instruments

a) Fair Value of Financial Instruments

Financial Instrument	Designated Category	Measurement Basis	Associated Risks	Fair Value at December 31, 2009
Cash and cash equivalents	Held for trading	Fair value	• Market • Credit • Liquidity	Measured at fair value
Accounts receivable	Loans and receivables	Initially at fair value and subsequently at amortized cost	• Credit • Liquidity	Carrying value approximates fair value due to short-term nature
Regulatory assets, short-term and long-term	Loans and receivables	Initially at fair value and subsequently at amortized cost	• Credit • Liquidity	Carrying value approximates fair value due to nature of asset [1]
Accounts payable and accrued liabilities	Other liabilities	Initially at fair value and subsequently at amortized cost	• Liquidity	Carrying value approximates fair value due to short-term nature [2]
Regulatory liabilities, short-term and long-term	Other liabilities	Initially at fair value and subsequently at amortized cost	• Liquidity	Carrying value approximates fair value due to nature of liability [1]
Long-term debt	Other liabilities	Initially at fair value and subsequently at amortized cost	• Market • Liquidity	$834.2 million [3]
Contributions in advance of construction	Held for trading	Fair value	• Market • Credit • Liquidity	Measured at fair value [4]
Contributions in advance of construction liability	Other liabilities	Initially at fair value and subsequently at amortized cost	• Liquidity	Carrying value approximates fair value due to the nature of the liability [4]
Operating and maintenance charges in advance	Held for trading	Fair value	• Market • Credit • Liquidity	Measured at fair value [5]
Operating and maintenance charges in advance liability	Other liabilities	Initially at fair value and subsequently at amortized cost	• Liquidity	Carrying value approximates fair value due to the nature ofthe liability [5]

1. Regulatory assets and liabilities are amounts collected in advance or under collected in revenue requirement which are settled either through a GTA or a separate filing. These amounts have typically been settled at or close to management's estimate.

2. Accounts payable and accrued liabilities are expected to mature in less than one year.

3. Fair values are determined using quoted market prices (which are classified as level 1 inputs) for the same or similar issues. Where market prices are not available, fair values are estimated using discounted cash flow analysis based on the Partnership's current borrowing rate for similar borrowing arrangements.

4. Contributions in advance of construction are held in short-term investments, the carrying values of which do not differ materially from the fair values. Contributions in advance of construction earned an effective interest rate of 0.25% for the year ended December 31, 2009 (December 31, 2008 - 1.49%). Interest received is accumulated throughout the year and paid annually to the AESO.

5. Operating and maintenance charges in advance are held in short-term investments, the carrying values of which do not differ materially from the fair values. Operating and maintenance charges in advance earned an effective interest rate of 0.25% for the year ended December 31, 2009 (December 31, 2008 - 1.49%).

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

b) Credit Risk

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

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

The Partnership has a concentration of credit risk as approximately 91% of its accounts receivable balance is due from the AESO (December 31, 2008 – 95%). For the year ended December 31, 2009, transmission tariff revenues accounted for approximately 92% (December 31, 2008 – 95%) of operating revenues. The remainder was comprised mainly of revenue from tower and land leases and the provision of services to other utilities.

The AESO is the Independent System Operator established as a statutory corporation under the EUA of the Province of Alberta, whose board members are appointed by the Alberta Minister of Energy. The remainder of the receivables are mostly from investment grade entities.

The Partnership does not require an allowance for doubtful accounts. As of December 31, 2009, over 99% of receivables have been outstanding for less than 30 days (December 31, 2008 – 99%).

The Partnership's maximum exposure to credit risk as at December 31, 2009, without taking into account collateral held, equalled the current carrying values of accounts receivable, contributions in advance of construction, operating and maintenance charges in advance and regulatory assets as disclosed in these financial statements.

c) Market Risk

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

i) Interest rate risk

Approximately 90% of the long-term debt issued by the Partnership has been approved by the AUC as regulatory debt, and the associated interest costs are fully recoverable through revenue requirements at approved interest rates. The Partnership is not exposed to interest rate risk with respect to the cost of the approved component of long-term debt issues during the current General Tariff Application period, due to deferral account treatment (note 7).

The non-regulated components of the long-term debt have been issued at fixed rates, maturing in 2012 and 2013, and the Partnership may be exposed to interest rate price risk upon renewal.

The Partnership's commercial paper, bankers' acceptances and bank loans have variable interest rates and, accordingly, expose the Partnership to interest rate cash flow risk through fluctuations in the variable interest rates.

To help manage interest rate risk, the Partnership controls the proportion of fixed and variable rate positions in accordance with the capital structure and ensures access to diverse sources of funding.

The Partnership's commercial paper, bankers' acceptances and bank loans are not subject to deferral account treatment. The Partnership forecasts the interest rate on its commercial paper, bankers' acceptances and bank loans in the GTA and is subject to interest rate risk. As at December 31, 2009, the Partnership had $48.0 million of commercial paper at an average rate of 0.40%. A 10% increase in short-term interest rates would increase interest expense and reduce net income for the year by $0.005 million.

ii) Foreign exchange risk

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

d) Liquidity Risk

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

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

To manage this risk, the Partnership ha s readily accessible standby credit facilities and other funding arrangements in place; generally uses financial instruments that are tradeable in highly liquid markets; and, has a liquidity portfolio structure wherein surplus funds are invested in highly liquid financial instruments.

6. Capital Risk Management

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

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

Summary of Capital Structure

	As at					
	December 31, 2009			December 31, 2008		
		(millions)	%		(millions)	%
Total long-term debt [1]	$	810.5	54.0	$	825.2	61.9
Partners' capital		549.0	36.6		408.5	30.7
Retained earnings		132.5	8.8		98.8	7.4
Cash and cash equivalents		8.3	0.6		—	—
Total	$	1,500.3	100.0	$	1,332.5	100.0

1. Does not include deferred financing fees of $6.4 million (December 31, 2008 - $6.9 million)

As at December 31, 2009, the Partnership was subject to externally imposed capital requirements under the Master Trust Indenture and the bank credit facilities described in note 10 - *Debt*. These reports limit the amount of debt that can be incurred relative to partners' equity. The Partnership was in compliance with these capital requirements as at December 31, 2009.

7. Regulatory Assets and Liabilities

(in thousands of dollars)		As at December 31, 2009		Change to regulatory asset/liability balance in 2009	Remaining recovery/ settlement period (years)		As at December 31, 2008
Regulatory assets							
Regulated financing fees A, B	$	791	$	(487)	2	$	1,278
Hearing costs reserve A, B		442		(74)	1-2		516
Canada Revenue Agency deferral		—		(542)	—		542
Debt cost deferral account A		977		—	1-2		977
500 kV costs		1,637		1,637	1		—
Total regulatory assets		3,847					3,313
Less: Current portion of regulatory assets		1,469					516
Regulatory assets, long-term	$	2,378				$	2,797
Regulatory liabilities							
Self-insurance reserve A, B	$	1,398	$	294	1-2	$	1,104
Pension liability account B		3,623		(162)	—		3,785
Pension asset offset *[note 9]*		2,042		(37)	—		2,079
Future income tax liability B		8,100		—	—		8,100
Property tax deferral account A		7,328		406	1-2		6,922
Insurance premium deferral account A, B		570		(88)	1-2		658
Debt cost deferral account A		2,269		2,146	1-2		123
Canada Revenue Agency reserve B		404		—	—		404
Annual tower payments account A		1,295		463	1-2		832
Direct Assigned Capital Projects deferral account B		133		(3,380)	1-2		3,513
Approved hearing costs		—		(13)	—		13
Site restoration		108,356		108,356	1-40		—
Total regulatory liabilities		135,518					27,533
Less: Current portion of regulatory liabilities		11,073					6,759
Regulatory liabilities, long-term	$	124,445				$	20,774

A. For the identified reserve and deferral accounts, the change in the regulatory asset/liability balance in the current year reflects the regulatory disposition of the opening balance or is equal to the difference between actual and approved forecast expenses, both of which are offset by a corresponding adjustment to revenue. Therefore the net income effect of the change in the reserve and deferral regulatory asset/liability account balances for the year ended December 31, 2009 is nil (December 31, 2008 – nil).

B. These identified regulatory asset and liability accounts are included in the rate base and affect the amount of return on investment.

For some of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by uncertainties relating to the ultimate authority of the AUC in determining the item's treatment for regulatory purposes.

The following describes each of the Partnership's circumstances in which rate regulation affects the accounting for a transaction or event:

Reserve Accounts

The Partnership's reserve accounts represent amounts that are initially established through AUC approval. Actual costs incurred in relation to the respective reserve are charged against the reserve, thereby decreasing the balance. If the Partnership's actual expenses are lower than the approved forecast, then the reserve will grow and may be released in the next regulatory period. If expenses are higher than forecast, the excess costs are recoverable in the next regulatory period, to the extent that they are considered prudent by the AUC.

The Partnership's revenue requirement is not adjusted for these differences until they are filed as part of the next application. However, as there is reasonable assurance of cost recovery, to reflect the revenue adjustment to the relevant period, the corresponding additional revenue is recognized in the financial statements as the reserve amounts are exceeded. Conversely, to the extent actual costs are less than the approved forecast, the Partnership correspondingly reduces the amount of revenue recognized in the current period.

The Partnership has a number of reserve accounts. The hearing costs reserve account represents a reserve for costs incurred, including those of intervenors, during hearings in which the Partnership is an Applicant. The self-insurance reserve provides coverage for uninsurable or uninsured losses and represents claims costs incurred by the Partnership. The Canada Revenue Agency (CRA) reserve captures the provincial tax effect of claims which have not yet received CRA approval. In the absence of rate regulation, these reserve accounts would not exist on the balance sheet and would be recorded as period expenses or revenue on the income statement.

The pension liability account represents amounts for pension expense which the Partnership collected in revenue but for which no contribution has been made into the plan. This liability has been extinguished to a certain extent, through required funding of the plan, while not recognizing any pension expense and resulting revenue, and it is expected that this will continue in the future.

Deferral Accounts

Deferral accounts are intended to mitigate the impact to customers as a result of variances between forecast and actual costs. To the extent actual costs differ from the approved forecast, the following year's revenue requirement may be adjusted accordingly. The Partnership has a number of deferral accounts. The Partnership's direct assigned capital deferral account captures the difference between the tariff earned on forecasted capital additions and those earned on actual capital additions for projects directly assigned by the AESO. The intent of the insurance premium deferral account is to capture the non-controllable cost variances with respect to commercial insurance premiums. The property tax deferral account is intended to capture the difference between forecast taxes other than income taxes and the actual taxes incurred. The long-term debt cost deferral account records the differences between the forecast and actual cost of a debt issue due to changes in interest rates, a change in term or change in the issue costs. The CRA deferral account records the differences between the forecasted provincial tax effect of expense claims and the actual expense claims which have been filed with the CRA.

The Annual Tower Payments account records the difference between the forecasted and actual expenses.

In the absence of rate regulation, these deferral accounts would not exist on the balance sheet and would be recorded as period expenses or revenue on the income statement.

500 kV Costs

In 2007, 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 the Partnership's 2009-2010 GTA, it asked the AUC to include approximately $38.6 million of costs related to the Genesee to Langdon 500 kV project in 2007 rate base. In its 2009-10 GTA Decision, the AUC: (i) stated that the Partnership should not be harmed financially by the project's cancellation; (ii) directed the Partnership to invoice the AESO for $35.0 million of the project costs; and (iii) directed the Partnership to recover the balance of the project costs in its 2009-10 revenue requirements. Pursuant to the AUC's directions, the Partnership invoiced the AESO for $35.0 million and included in its 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 the Partnership to recover the $35.0 million amount under its 2009-10 tariffs. The AESO paid $35.0 million to the Partnership 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, the Partnership accounted for the voided 500 kV project costs as capital assets, consistent with its 2009-2010 general tariff application. Following the 2009-10 GTA Decision, the Partnership reclassified the remaining net book value of $36.7 million from capital assets to regulatory assets. When the AUC rules on its compliance filing, it will recognize the difference, if any, between the amount it is allowed to recover and the amounts it previously recognized in its financial statements. The Partnership expects that the AUC's ruling on its compliance filing will not have a material adverse impact on its financial results.

Regulated Financing Fees

As directed by the AUC, finance fees associated with the Partnership's initial Bridge Bonds were rolled over into replacement debt and they are being recovered in transmission revenue over the terms of the new debt issues: five years (2003-2008) for the $100 million debt issue, 10 years (2003-2013) for the $200 million debt issue, and approximately 9.5 years for the $125 million debt issue. The balance represents the unrecovered debt issue costs. In the absence of rate regulation, GAAP would require the write-off of unamortized debt issue costs in the year the debt is retired.

Deferred financing fees are being amortized using the effective interest rate method. For the year ended December 31, 2009, amortization of finance fees totalled $1.6 million (December 31, 2008 - $1.7 million), which is $0.5 million (December 31, 2008 - $0.5 million) higher than would have been recorded in the absence of rate regulation.

Pension Asset Offset

In order to recognize the pension expense or income in these financial statements on the same basis as it is recovered through the rates charged to customers, a regulatory liability has been established which is equal to the pension asset recognized. This liability is being reduced or increased on the same basis as the pension asset is reduced or increased.

In the absence of rate regulation, under GAAP, the amount of pension expense that would have been recorded for the year ended December 31, 2009 is $3.8 million (December 31, 2008 - $3.0 million) versus $3.4 million (December 31, 2008 - $2.7 million) actually recorded as a result of rate regulation. Consequently, net income for the year ended December 31, 2009 is $0.4 million (December 31, 2008 - $0.3 million) higher than would have been recorded in the absence of rate regulation.

Future Income Tax Liability

As a limited partnership, AltaLink does not pay federal or provincial income taxes directly. Instead, income taxes are paid by the corporations that ultimately hold limited partnership interests in the Partnership. The revenue requirement includes an allowance for income taxes attributable to the Partnership's regulatory net income. In calculating this allowance, the Partnership currently uses 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 the Partnership's 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 the Partnership with higher tariffs and cash flow to support cash flow credit metrics during the construction of major transmission projects. Previously, in Decision 2007-012, the AUC had directed the Partnership to switch to the flow-through method for federal income taxes in 2009 and subsequent years. The AUC approved the Partnership'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 the Partnership to recommend options as to the disposition of federal future income taxes paid in previous periods.

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. The Partnership is required to use its deemed capital structure and the generic return on equity when calculating tariff revenue requirements.

In its 2009 GCOC Decision, the AUC increased the Partnership's 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.

Other Items Affected by Rate Regulation

The AUC permits AFUDC to be included in the rate base, based on the Partnership's weighted average cost of capital. AFUDC is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated over future periods as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFUDC component, will be approved for inclusion in future customer rates. Since AFUDC includes not only an interest component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation.

The regulatory rate base consists of property, plant and equipment less the cost of assets under construction and includes a provision for working capital, site restoration costs, and the regulatory asset and liability accounts identified in the table below.

8. Property, Plant & Equipment

(in thousands of dollars)	Lines [1]	Substations [2]	Buildings & Equipment [3]	Land & CWIP [4]	Long Lived Assets [5]	Customer Contributions [6]	Total
Cost							
As at Jan 1, 2008	$ 501,908	$ 767,238	$ 89,357	$ 140,618	$ 44,165	$ (106,489)	$ 1,436,797
Additions	68,612	86,060	22,793	4,252	1,771	(33,117)	150,371
Retirements	(1,282)	(1,526)	(6,204)	(28)	(751)	—	(9,791)
As at Dec 31, 2008	569,238	851,772	105,946	144,842	45,185	(139,606)	1,577,377
Additions	47,669	126,918	35,052	156,200	117,142	(23,903)	459,078
Retirements	(1,321)	(1,019)	(8,108)	(49)	—	—	(10,497)
Reclass voided 500 kV costs	(29,090)	(2,159)	—	(5,388)	—	—	(36,637)
As at Dec 31, 2009	**$ 586,496**	**$ 975,512**	**$ 132,890**	**$ 295,605**	**$ 162,327**	**$ (163,509)**	**$ 1,989,321**
Accumulated Depreciation							
As at Jan 1, 2008	$ (85,467)	$ (164,436)	$ (25,474)	$ —	$ (21,062)	$ 11,260	$ (285,179)
Depreciation expense	(30,461)	(50,454)	(8,861)	—	(2,281)	4,251	(87,806)
Retirements & salvage	9,604	2,741	6,118	—	751	—	19,214
As at Dec 31, 2008	(106,324)	(212,149)	(28,217)	—	(22,592)	15,511	(353,771)
Depreciation expense	(19,320)	(45,340)	(10,760)	—	—	5,175	(70,245)
Reclass SRC	77,657	48,786	272	—	18,360	—	108,355
Retirements & salvage	2,932	3,441	7,957	—	—	—	14,330
As at Dec 31, 2009	**$ (45,055)**	**$ (205,262)**	**$ (30,748)**	**$ —**	**$ (40,952)**	**$ 20,686**	**$ (301,331)**
Net Book Value							
As at Dec 31, 2008	$ 462,914	$ 639,623	$ 77,729	$ 144,842	$ 22,593	$ (124,095)	$ 1,223,606
As at Dec 31, 2009	**$ 541,441**	**$ 770,250**	**$ 102,142**	**$ 295,605**	**$ 121,375**	**$ (142,823)**	**$ 1,687,990**

1. Lines – transmission lines, related equipment and surface rights.

2. Substations – substation and telecontrol equipment.

3. Buildings & Equipment – Office buildings, vehicles, tools and instruments, office furniture, telephone and related equipment and computer hardware and software.

4. Land & CWIP – Land, capitalized inventory and emergency capital spare parts and assets under construction.

5. Long-Lived Assets – originally established as the offset to the Asset Retirement Obligations (see note 11).

6. Customer Contributions – Customer contributions (see note 3e).

The total amount of AFUDC capitalized for the year ended December 31, 2009 was $13.9 million ($5.8 million for the year ended December 31, 2008) at a capitalization rate of 6.81% (6.72% for the year ended December 31, 2008).

The following table provides a reconciliation of our cash capital expenditures:

(in thousands of dollars)	
Increase in net book value in the year [1]	$ 464,384
Add: Proceeds from disposals of assets	3,841
Depreciation	70,245
Customer contributions related to capital expenditures	70,552
Less: Non-cash items	
Gains on disposals of assets	3,792
AFUDC	13,878
Reclassification of site restoration	108,355
Increase in ARO	118,456
Capital expenditures	$ 364,541

1. Included in this figure is $23.9 million for customer contributions related to capital additions.

9. Employee Future Benefits Plans

	Year ended			
	December 31, 2009		December 31, 2008	
(in thousands of dollars)	Pension Plan	Other Benefits	Pension Plan	Other Benefits
Fair value of plan assets				
Balance, beginning of year	$ 7,011	$ —	$ 8,420	$ —
Employee contributions	14	—	17	—
Company contributions	212	1	101	9
Benefit payments	(222)	(1)	(131)	(9)
Actual gain (loss) on plan assets	1,113	—	(1,396)	—
Balance, end of year	8,128	—	7,011	—
Accrued benefits obligation				
Balance, beginning of year	6,625	1,971	7,941	2,454
Current service cost	75	283	149	347
Employee contributions	14	—	17	—
Benefit payments	(222)	(1)	(131)	(9)
Interest cost	495	165	439	152
Experience (gain) loss	627	245	(1,790)	(973)
Balance, end of year	7,614	2,663	6,625	1,971
Funded status				
Funded status – surplus (deficit)	514	(2,663)	386	(1,971)
Supplemental pension plan	—	(457)	—	(346)
Unamortized past service costs	—	317	—	371
Unamortized actuarial losses (gains)	1,528	(231)	1,794	(496)
Solvency deficiency payment	—	—	(101)	—
Accrued asset (liability), end of year	$ 2,042	$ (3,034)	$ 2,079	$ (2,442)
Amortization period in years	4	15	4	15
	%	%	%	%
Discount rate for funded status	6.70	6.00	7.50	7.40
Discount rate for expense determinations	7.50	7.40	5.50	5.50
Expected long-term rate of return on plan assets	7.00	—	7.00	—
Rate of compensation increase	4.00	—	4.00	—
Health care cost escalation	—	5.00	—	5.00
Dental care cost escalation	—	5.00	—	5.00
Provincial health care premium escalation	—	N/A	—	3.50

a) Description

The General Partner employs staff and provides administrative and operational services to the Partnership on a cost reimbursement basis. As part of the purchase of the transmission assets the Partnership assumed pension obligations in respect of the transmission employees that are part of the defined benefit plan. At the valuation date of April 30, 2002, pension assets to be transferred exceeded the related liabilities assumed. The pension obligation was transferred by the Partnership to the General Partner at the value of the pension surplus and the Partnership is credited with any pension income and charged for any pension expense. The transfer resulted in a long-term pension asset being established in the Partnership which is being reduced through pension expense charges or increased by pension income. Any cash funding of the pension plan by the General Partner is reimbursed by the Partnership. The Partnership has indemnified the General Partner for all costs and liabilities associated with its employment of staff, including any pension liabilities. As such the pension is reported as if it is held by the Partnership even though the legal plan sponsor and employer of the staff is the General Partner.

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

The latest actuarial valuation was done as at December 31, 2007, and extrapolated to December 31, 2009. The effective date of the next required valuation for funding purposes is December 31, 2010.

Other accrued employment benefits include the health and dental coverage provided to some employees.

In addition, the General Partner has a supplemental pension plan. The supplemental pension plan is provided to those employees who exceed the income tax limits on maximum pension contributions in a year. The supplemental pension plan is a defined contribution plan with 8% (2008 – 6%) employer contributions, which is not registered. Membership in the supplemental pension plan is automatic once registered pension plan contributions have reached the maximum annual amount.

b) Costs Recognized

	Year ended			
	December 31, 2009		December 31, 2008	
(in thousands of dollars)	Registered	Other	Registered	Other
Current service cost	$ 75	$ 283	$ 149	$ 347
Interest cost on benefit obligation	495	165	439	152
(Gain) loss on plan assets	(1,113)	—	1,396	—
Experience (gain) losses	627	245	(1,790)	(973)
Difference between expected return and actual return on plan assets	619	—	(1,987)	—
Difference between actuarial (gain) loss recognized for the year and actual actuarial (gain) loss on accrued benefits obligation for the year	(353)	(265)	2,042	990
Difference between amortization of past service costs for the year and actual plan amendments for the year	—	53	—	53
Expense	350	481	249	570
Regulatory adjustment to offset expense	(350)	—	(249)	—
Defined contribution expense of registered pension plan	3,415	—	2,729	—
Supplemental pension expense	—	112	—	67
Net expense recognized in the financial statements	$ 3,415	$ 593	$ 2,729	$ 637

Sensitivity to changes in assumed health care cost trend rates as at December 31, 2009 are as follows:

(in thousands of dollars)	One percentage point increase	One percentage point decrease
Effect on total service and interest cost	$ 58	$ (50)
Effect on post-retirement benefits obligation	332	(289)

The asset mix of the defined benefit component of the pension plan as of December 31, 2009 consists of 59% equity, 37% bonds, and 4% cash (December 31, 2008 – 55% equity, 39% bonds and 6% cash).

10. Debt

(in thousands of dollars)	Effective Interest Rate	Maturing	As at December 31, 2009	December 31, 2008
Senior Debt *[note 10d]*				
Series 03-2, 5.430%	**5.804%**	2013	$ 325,559	$ 325,701
Series 2006-1, 5.249%	**5.299%**	2036	150,000	150,000
Series 2008-1, 5.243%	**5.312%**	2018	100,000	100,000
Series 2008-1 (additional issue), 5.243%	**5.328%**	2018	102,358	—
			677,917	575,701
Series 3, subordinated 8.000% *[note 12]*	**8.020%**	2012	85,000	85,000
Commercial paper *[note 10b]*	**0.501%**	2011	47,982	26,951
Bank credit facilities *[note 10b]*	**N/A**	2011	—	137,735
			810,899	825,387
Less: Deferred financing fees				
Series 3, 8.000%			42	55
Series 03-2, 5.430%			3,796	4,769
Series 2006-1, 5.249%			1,068	1,086
Series 2008-1, 5.243%			878	891
Series 2008-1 (additional issue), 5.243%			632	56
			6,416	6,857
Total debt, net of deferred financing fees			804,483	818,530
Less: current portion of long-term debt			376	142
Total long-term debt			$ 804,107	$ 818,388

The Partnership does not intend to redeem any of its long-term debt prior to maturity.

On May 16, 2008, the Partnership filed a short form base shelf prospectus to facilitate the issuance of medium-term notes. This shelf prospectus has a 25-month life and permits the Partnership to issue up to an aggregate of $800.0 million of secured, medium-term notes. On May 29, 2008, $100.0 million of Series 2008-1 notes were issued under the shelf prospectus and the proceeds were used to repay $100.0 million of Series 03-1 notes, which matured on June 5, 2008. On May 14, 2009, $100.0 million of additional Series 2008-1 medium-term notes were issued under the shelf prospectus and the proceeds were used to repay outstanding commercial paper. The Series 2008-1 notes are senior secured obligations of the Partnership. Collateral for the secured debt obligations consists of a first floating charge security interest on the Partnership's present and future assets. Additional Series 2008-1 notes were issued at a premium of $2.6 million, which will be amortized over the term of the related debt.

a) Capital Markets Platform

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

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

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

The Partnership has secured the obligations relating to the Series 03-2 Senior Bonds, Series 3 Subordinated Bonds, Series 2006-1 Medium-term Notes, Series 2008-1 Medium-term Notes and its credit facilities. Collateral for the secured debt obligations consists of a first floating charge security interest on the Partnership's present and future assets. The Series 03-2 Senior Bonds, Series 2006-1 Medium-term Notes, Series 2008-1 Medium-term Notes and the credit facilities rank equally with each other and all future senior secured indebtedness that is issued by the Partnership.

b) Bank Credit Facilities

As at December 31, 2009, the Partnership had $485.0 million (2008 - $285.0 million) of committed bank credit facilities which mature in 2011.

As at December 31, 2009 (in thousands of dollars)	**Committed**	**Drawdowns**	**Commercial Paper Outstanding**	**Availability**	**Maturity Date**
Commercial paper back-up facility	**$ 400,000**	**$ —**	**$ 47,982**	**$ 352,018**	**December 17, 2011**
Revolving line of credit	**85,000**	**—**	**—**	**85,000**	**April 30, 2011**
	$ 485,000	**$ —**	**$ 47,982**	**$ 437,018**	

As at December 31, 2008 (in thousands of dollars)	Committed	Drawdowns	Commercial Paper Outstanding	Availability	Maturity Date
Commercial paper back-up facility	$ 200,000	$ 137,735	$ 26,951	$ 35,314	December 10, 2011
Revolving line of credit	85,000	—	—	85,000	May 1, 2011
	$ 285,000	$ 137,735	$ 26,951	$ 120,314	

The commercial paper back-up facility provides support for the borrowing under the unsecured commercial paper program of $200.0 million. Drawdowns under the commercial paper back-up facility may be in the form of Canadian prime rate loans and bankers' acceptances. As at December 31, 2009, borrowing under this facility was nil (December 31, 2008 – $137.7 million). Commercial paper issued reduces the availability under the $400.0 million commercial paper back-up facility. As at December 31, 2009, commercial paper outstanding was $48.0 million (December 31, 2008 - $27.0 million). The average term to maturity for outstanding commercial paper was 11 days as at December 31, 2009 (December 31, 2008 – 11 days) with a weighted average interest rate of 0.40% (December 31, 2008 – 2.72%).

The $85.0 million credit facility may be used for capital expenditures and general corporate purposes. This $85.0 million facility bears interest at either the lenders' rates for Canadian prime rate loans, U.S. base rate loans, bankers' acceptances or LIBOR loans, plus applicable margins.

c) Letters of Credit

As at December 31, 2009, the Partnership had secured letters of credit outstanding totaling $0.1 million (December 31, 2008 - $0.1 million).

d) Debt Facilities

Series 03-1, Series 03-2, Series 2006-1 and Series 2008-1

The Series 03-1 Senior Bonds had no provision for early redemption and matured on June 5, 2008. The Series 03-2 Senior Bonds, Series 2006-1 and Series 2008-1 medium-term notes are redeemable by the Partnership at the greater of (i) the prevailing Government of Canada bond yield plus a pre-determined premium, and (ii) the face amount of the debt to be redeemed plus, in each case, accrued and unpaid interest.

e) Interest Expense and Amortization of Deferred Financing Fees

	Year ended	
(in thousands of dollars)	December 31, 2009	December 31, 2008
Deferred financing fees amortized	$ 1,604	$ 1,697
Interest on debt	42,818	42,472
Total interest and amortization of deferred financing fees on debt	44,422	44,169
Less: short-term portion of interest on debt	—	—
Total long-term portion of interest and amortization of deferred financing fees	$ 44,422	$ 44,169

f) Scheduled Principal Repayments

(in thousands of dollars)	
Maturing	
2010	$ 376
2011	47,982
2012	85,000
2013	325,409
2014	—
2015 and thereafter	352,132
	$ 810,899

11. Asset Retirement Obligations

As of December 31, 2009 the estimated total undiscounted amount of asset retirement obligations was approximately $453.1 million (December 31, 2008 - $130.7 million). The obligations will be settled over the useful lives of the assets, with the majority of the retirements estimated to occur between 2010 and 2050. In determining the fair value of the asset retirement obligations, the estimated cash flows of new obligations incurred during the year have been discounted, using a discount rate adjusted for credit risks and inflation factors, at 4.96% (2008 – 6.73%). The depreciation rates included in the regulatory revenue requirements include an amount to enable the Partnership to cover the costs of present and future asset retirement obligations. As depreciation expense is recovered through the General Tariff Application process, there is no net income effect on the Partnership's financial statements.

During the second quarter of 2009, the Partnership updated its estimate of costs with the assistance of an independent third party, resulting in an increase in the discounted asset retirement obligations of $86.6 million. The change is mainly the result of an increase in labour costs.

	As at	
(in thousands of dollars)	December 31, 2009	December 31, 2008
Balance, beginning of year	$ 60,181	$ 57,954
Net change in liabilities for the year	118,455	1,915
Liabilities settled in year	(1,236)	(2,651)
Accretion expense	8,905	2,963
Balance, end of year	$ 186,305	$ 60,181

Retirement obligations may apply to both the retirement of an entire facility or to parts of the larger system. Interim retirement obligations are recognized in the latter circumstances, when a component is retired prior to the retirement of the entire facility. Asset retirement obligations are recorded as a liability, with a corresponding increase to capital assets.

The Partnership analyzed the component parts of the system to determine whether it has legal obligations associated with the transmission system. The transmission system includes transmission lines, substations and telecom equipment.

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

The Partnership has determined that there are legal obligations associated with the interim retirement of the component parts of the transmission lines. The calculation of costs to dismantle and remove the component parts, including poles and towers, was estimated using historical information regarding the replacement and retirement of these types of assets.

No asset retirement obligation has been recognized for the final retirement and removal of the transmission lines as the date of the retirement, and therefore the fair value of the obligation, cannot be determined.

12. Related Party Transactions

The Partnership is related to the following companies: SNC-Lavalin Group Inc. (SNC); SNC-Lavalin Transmission Ltd., SNC-Lavalin Transmission II Ltd., SNC-Lavalin Energy Alberta Ltd., SNC-Lavalin Capital Inc., Macquarie Group Inc., Macquarie Transmission Alberta Ltd. and Macquarie GP Holdings Ltd.

In 2002, the Partnership executed a 10-year contract for engineering, procurement and construction management services. These services are provided to the Partnership by SNC-Lavalin ATP Inc., a wholly-owned subsidiary of SNC. The terms and conditions of this contract have been reviewed by the AUC and are subject to ongoing regulatory oversight.

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

	As at	
(in thousands of dollars)	December 31, 2009	December 31, 2008
Receiving/(Rendering) of Services		
Interest on Series 3 Subordinated Bond		
AltaLink Investments, L.P.	$ 6,800	$ 6,800
Employee compensation and benefit charges		
AltaLink Management Ltd.	58,858	47,610
Miscellaneous revenue		
AltaLink Investments, L.P.	(211)	(192)
AltaLink Holdings, L.P.	(133)	(135)
Construction related services in Property, Plant and Equipment		
SNC-Lavalin ATP Inc.	200,103	54,423

During the years ended December 31, 2009 and 2008, there were other transactions which were not material individually or in total with SNC-Lavalin Capital Inc., Macquarie North America Ltd., AltaLink Investment Management Ltd., SNC-Lavalin Environmental Inc., and SNC-Lavalin Inc.

Amounts included in accounts receivable and accounts payable are:

(in thousands of dollars)	As at December 31, 2009 Amount owed (to)/from related parties	December 31, 2008 Amount owed (to)/from related parties
AltaLink Management Ltd.	$ (6,882)	$ (4,873)
SNC-Lavalin ATP Inc.	(82,995)	(17,231)
AltaLink Investments, L.P.	(1,063)	(1,092)

As at December 31, 2009 and 2008 accounts receivable and accounts payable included amounts which are not material individually or in total that were owed to/from related parties including AltaLink Investment Management Ltd., AltaLink Holdings, L.P., Macquarie North America Ltd., Heartland Transmission, L.P., Heartland Transmission Management Ltd. and AltaLink Heartland Holdings, L.P.

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

Remuneration of Senior Management

(in thousands of dollars)	Year ended December 31, 2009	December 31, 2008
Salary and other short-term benefits	$ 2,729	$ 2,315
Other long-term benefits	585	566
Post employment benefits	207	162
Total for all senior management	$ 3,521	$ 3,043

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

Salary and other short-term benefits represent actual salary received during the year, and annual short-term incentive plan that pays out based on the achievement of specific predetermined performance goals and perquisites. Other long-term benefits represent long-term incentive plan (LTIP) award grants earned during the year. LTIP provides incentives aligned with the value created for AltaLink's customers and partners. Post-employment benefits include the defined contribution pension plan and supplemental pension plan.

Remuneration of Board of Directors of General Partner

(in thousands of dollars)	Year ended December 31, 2009	December 31, 2008
Total fees earned by Directors [1]	$ 359	$ 307

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

13. Transmission Tariff

AltaLink is regulated under a cost-of-service methodology under which all prudently incurred costs are recovered in addition to an allowed return on the rate base.

	Year ended	
(in thousands of dollars)	December 31, 2009	December 31, 2008
Return – Equity [1]	$ 33,900	$ 29,900
Return – Debt [2]	38,500	39,600
Recovery of expenses	154,400	149,500
Deemed income taxes	11,200	9,700
Approved transmission tariff	238,000	228,700
Deferral and reserve account adjustments	(1,866)	(6,472)
Transmission tariff	$ 236,134	$ 222,228

1. In 2009, the approved return on equity (ROE) was 9.00%, with a deemed common equity ratio of 36%. The Partnership was approved an ROE of 8.75% with deemed common equity ratio of 33% in 2008.

2. In 2009, the Partnership was approved a return on debt (ROD) of 5.58%, with a deemed common equity ratio of 64%. In 2008, the approved ROD was 5.78%, with a deemed common equity ratio of 67%.

14. Miscellaneous Revenue

	Year ended	
(in thousands of dollars)	December 31, 2009	December 31, 2008
Capital related service contracts to third parties [1]	$ 7,726	$ 2,132
Recovery of costs for services provided to other utilities	4,711	4,722
Tower, land and other lease revenue	1,573	1,171
Related party and other billings	917	631
Miscellaneous revenue	$ 14,927	$ 8,656

1. There is no significant net income impact as this revenue is based on cost recovery.

15. Supplemental Cash Flow Information

	Year ended	
(in thousands of dollars)	December 31, 2009	December 31, 2008
(Increase) decrease in accounts receivable	$ (3,545)	$ 20,727
(Increase) decrease in prepaid expenses and deposits	3,830	(3,369)
Increase in accounts payable and accrued liabilities	77,465	1,295
Increase (decrease) in other liabilities	434	(49)
Increase in current regulatory assets and liabilities	3,362	928
Change in non-cash working capital items	81,546	19,532
Related to investing activities	(71,890)	5,452
Related to operating activities	$ 9,656	$ 24,984

16. Net Change in Other Financing Activities

(in thousands of dollars)	Year ended December 31, 2009	December 31, 2008
Deferred financing fees paid	$ (676)	$ (984)
Increase in contributions in advance of construction	(10,870)	(1,238)
Increase in contributions in advance of construction liability	10,870	2,014
Increase in operating and maintenance charges in advance	(4,489)	(5,351)
Increase in operating and maintenance charges in advance liability	4,489	5,351
	$ (676)	$ (208)

17. Regulatory Decisions

The effects of the following Decisions have been reflected in these financial statements:

a) 2004-06 Deferral Accounts

Decision 2008-076 was issued on August 26, 2008 confirming full recovery of the Direct Assign capital deferral account for May 2004 through December 2006 and the disposition of other deferral accounts. On January 30, 2009, the Partnership was directed to settle the related regulatory assets and liabilities with the AESO in the amount of $1.4 million, which was paid on February 17, 2009.

b) 2009-2010 GTA & GCOC Decisions

On October 2, 2009, the AUC issued Decision 2009-151 regarding the Partnership's General Tariff Application for 2009 and 2010 and on November 12, 2009 the AUC issued Decision 2009-216 regarding the Generic Cost of Capital (GCOC) proceeding. On December 23, 2009, the Partnership submitted a Compliance Filing Application to reflect the findings, conclusions and directives of both of these decisions. The Partnership has reflected its best estimate of the GTA Decision, the GCOC Decision and the Compliance Filing in these financial statements. In accordance with the Partnership's accounting policy outlined in note 3(a), any effects of the AUC's final decision on the Partnership's Compliance Filing Application will be reflected in the financial statements in the period in which the decision is issued.

c) Genesee to Langdon 500 kV Project Costs

In Decision 2009-151, the Partnership was directed to recover $35.0 million of costs related to the Genesee to Langdon 500 kV project from the AESO and to include the balance of the costs in the 2009-2010 revenue requirements. On December 31, 2009 the Partnership received $35.0 million from the AESO, which is reflected in these financial statements.

18. Commitments

On September 22, 2005 the Partnership entered into a 20-year operating lease for its head office. The Partnership is committed to additional operating leases for other premises in Red Deer, Lethbridge and Calgary that all have lease terms up to five years. Of the total expected minimum lease payments, 85% relates to the Partnership's head office leases.

Expected minimum lease payments in future years are as follows:

	Year ended			
(in thousands of dollars)	December 31, 2009		December 31, 2008	
Operating lease obligations payable on non-cancellable leases are as follows:				
No later than 1 year		$ 3,199		$ 3,549
No later than 2 years	3,583		3,166	
No later than 3 years	3,564		3,166	
No later than 4 years	3,335		3,166	
No later than 5 years	2,710		3,047	
Later than 1 year and no later than 5 years		13,192		12,545
Later than 5 years		24,760		27,557
		$ 41,151		$ 43,651

19. Contingencies

In Decision 2007-012, the AUC had directed the Partnership, effective January 1, 2009 to begin using the flow-through (i.e. current taxes payable) method for determining deemed federal and provincial income tax expenses to be included in its revenue requirement. The AUC also indicated that a determination with respect to the accumulated but unpaid future income tax amounts as at December 31, 2008 would have to be made. In Decision 2009-151, the AUC approved the Partnership's proposal to continue using the future income tax method for 2009 and 2010 and indicated that it will review the matter again at the time of the next GTA. As a result, there is no impact on the Partnership's financial statements.

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

20. Partners' Capital

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

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

Any units issued by the Partnership must first be offered to the existing limited partners in proportion to their ownership interests. Any units offered for sale by any of the existing limited partners to non-owners must first be offered to the existing limited partners. Generally, only units not purchased by the existing limited partners can be issued to outside parties.

During the year, the Partners invested additional equity of $140.5 million (2008 – nil). No partnership units were issued during the year (2008 – nil).

21. Comparative Figures

Certain comparative figures have been reclassified to conform to the current year's presentation.

CORPORATE GOVERNANCE

The role of the Board and its committees is to provide independent, effective leadership to supervise the management of AltaLink's business and affairs. AltaLink supports this role through its dedication to leading corporate governance systems modelled on guidelines recommended as best practices by security regulators.

AltaLink is proud of its commitment to corporate governance and believes that good governance practices add value for all stakeholders. AltaLink's Board is entirely independent from management and comprised of a diverse group of experienced individuals all with the same goal of providing responsible stewardship for AltaLink. The Board is therefore able to act in the best interests of AltaLink without being unduly influenced by management.

AltaLink's dedication to strong corporate governance practices is also exemplified through the requirements for its Audit Committee. AltaLink voluntarily elects to have its Audit Committee meet the standards set for publicly listed companies, including requiring its members to be independent and financially literate. AltaLink believes that such practices support higher investor confidence in its financial controls and reporting.

As part of its practices, AltaLink provides orientation for new directors and continuing education initiatives for the Board as a whole. The Board has also approved the AltaLink Code of Ethics as a statement of the ethical principles expected of AltaLink's directors, officers and employees.

The Board is currently comprised of nine members: David Tuer (Chairman of the Board), Michael Bernstein, Jack Bittan, Jim Burke, Gilles Laramée, Paul McCoy, Douglas Mitchell Q.C., Patricia Nelson and Robert Turgeon.

Board Committees

The stewardship of AltaLink is the responsibility of the Board and its three committees: the Audit Committee, the Human Resources and Governance Committee and the Environmental, Health and Safety Committee.

Audit Committee

Chair: Patricia Nelson
Members: David Tuer and Robert Turgeon

The primary purpose of the Audit Committee is to assist the Board in fulfilling its oversight responsibilities for financial reporting, controls and risk management. The Committee meets regularly with AltaLink's external and internal auditors and reviews financial security filings, such as the annual and quarterly financial statements and management's discussion and analysis, before they are approved by the Board. The Committee also reviews and makes a recommendation to the Board in respect to the appointment of the external auditor and monitors accounting, financial reporting, control and audit functions.

The Audit Committee meets to discuss and review the audit plans of internal and external auditors, and questions the external and internal auditors independently of management. Responsibilities also include reviewing and reporting to the Board on AltaLink's risk management policies and procedures and reviewing results from the testing of key internal controls. The Committee is responsible for the implementation and effectiveness of AltaLink's Code of Ethics and for monitoring compliance with the Inter-Affiliate Code of Conduct.

Audit Committee members are independent of AltaLink's management, owners, and auditors, and they bring a wealth of experience in understanding and supervising financial reporting. The Chair of the Audit Committee, Ms. Nelson, is the former Minister of Finance for the Province of Alberta and served on the Alberta Treasury Board for 12 years, including four years as Chair of the Treasury Board.

Human Resources and Governance Committee

Chair: Paul McCoy
Members: Michael Bernstein, Gilles Laramée and Douglas Mitchell, Q.C.

Among its responsibilities, the Human Resources and Governance Committee performs the functions of a compensation committee and a nominating committee. Its mandate includes the responsibility to assist the Board on human resources and corporate governance issues, and management of AltaLink on human resource matters. The Committee is specifically committed to the continuing review, development and improvement of strong corporate governance practices which the Board and management believe are the cornerstones of investor trust and good management.

The Human Resources and Governance Committee reviews succession plans for key management positions within AltaLink, human resources policies and plans, and the performance and development of the CEO and other senior officers of AltaLink. It also makes recommendations to the Board in respect of CEO compensation and other compensation matters, such as incentive programs and benefits. The Committee is also responsible for reviewing the compensation set for Board and committee service.

It is the Committee's mandate to assess the effectiveness of the Board as a whole, its committees and individual members. It assesses AltaLink's approach to corporate governance (including its internal policies and codes of conduct) and monitors the relationship between management and the Board. The Committee is also responsible for the implementation of initiatives to maintain AltaLink's high standard of corporate governance practices.

Environmental, Health and Safety Committee

Chair: Robert Turgeon
Members: Patricia Nelson and David Tuer

The Environmental, Health and Safety Committee was established in 2008 to assist the Board in its oversight of environmental, health and safety (EH&S) matters at AltaLink. Among its responsibilities, the Committee reviews AltaLink's response to EH&S issues, including compliance with applicable legislation, regulatory requirements and industry standards.

The Committee is also responsible for reviewing AltaLink's programs for EH&S assurances and the implementation of relevant policies. To accomplish these goals, the Committee helps develop internal and external audit plans and reviews the results of all such audits. The Committee also receives regular reports on incidents and compliance from management and would be expected to review in depth any significant incidents or events of non-compliance should they occur.

Members of the Committee are all independent of AltaLink's management, owners, and auditors, and they bring valuable expertise to overseeing the development and implementation of systems and programs for the management of EH&S matters.

BOARD OF DIRECTORS

David Tuer

Chairman of the Board

Mr. Tuer is the Vice Chairman and Chief Executive Officer of a private oil and gas company. He is an independent businessman and was Chairman of the Calgary Health Region from 2001 to 2008. He has held senior executive positions in various energy companies throughout his career. He is the former President and Chief Executive Officer of PanCanadian Petroleum Limited, prior to its merger in 2002 with the Alberta Energy Company to form EnCana Corporation. He also serves on the Board of Directors of a number of public companies, including Canadian Natural Resources Limited.

Michael Bernstein

Director

Mr. Bernstein is the President and Chief Executive Officer of Macquarie Power and Infrastructure Income Fund, the President and Chief Executive Officer of Macquarie Essential Assets Partnership and President of Macquarie Capital Funds Canada Ltd. Previously, he was Head of Macquarie's Infrastructure and Utilities advisory team in Canada. Mr. Bernstein is a director of a number of companies, including Macquarie North America Ltd., Sea to Sky Highway and Leisureworld Senior Care. Prior to joining Macquarie in 2005, Mr. Bernstein was a senior member of the Power and Utilities Group at CIBC World Markets Inc. He holds a Masters in Business Administration from the University of Western Ontario and a Bachelor of Arts from Dartmouth College and the CFA designation.

Jack Bittan

Director

Mr. Bittan is Senior Vice President of Macquarie Capital Funds Canada Ltd. where he is responsible for the evaluation and strategic management of infrastructure investments in North America. Prior to joining Macquarie in 2004, Mr. Bittan worked in the financial services practice group at PricewaterhouseCoopers LLP. He is a director of Macquarie Canada Highway Holdings Ltd. and Access Roads Edmonton Ltd. Mr. Bittan holds Honours Bachelor of Science and Master of Management degrees from the University of Toronto and is designated as a Chartered Accountant (Ontario).

Jim Burke

Director

Mr. Burke is Executive Vice President of SNC-Lavalin Group Inc. and a member of SNC-Lavalin's Office of the President. He is responsible for SNC-Lavalin's worldwide transportation and environment operations. Mr. Burke has extensive experience in the design, construction and management of transit systems, and led SNC-Lavalin's $1.9 billion Canada Line LRT project. Mr. Burke also has significant experience in the transmission and distribution industry where he spent over 15 years of his career working both for the City of Calgary Electric System and on a major hydroelectric project in British Columbia. Mr. Burke holds a Bachelor of Science degree in Electrical Engineering from the University of Calgary, and is a member of the Association of Professional Engineers and Geoscientists in British Columbia.

Gilles Laramée

Director

Mr. Laramée is a chartered accountant with 25 years experience in business acquisitions, corporate and project financing, financial reporting and controls, external auditing, investment, and asset management and taxation. He has a Bachelor of Business Administration, with a major in Public Accounting from the University of Montreal's School of Business Administration, HEC, and has completed the Advanced Management Program at Harvard University. He is also a Fellow of the Order of Chartered Accountants of Quebec. Since 1999, Mr. Laramée has held the position of Executive Vice President and Chief Financial Officer of SNC-Lavalin. He has played a key role in many aspects of SNC-Lavalin's financial operations.

Paul McCoy

Director

Mr. McCoy is President of Trans-Elect Development Company, LLC, an independent electric transmission company located in the United States. He also provides consulting services through McCoy Energy, LLC. Prior to co-founding the original Trans-Elect in 1999, he spent 27 years at Commonwealth Edison (ComEd), lastly as Executive Senior Vice President of Unicom (ComEd's holding company), and President of ComEd's Transmission Group. Mr. McCoy has held numerous leadership positions in major transmission industry organizations and has significant experience working with state and federal utility regulators in the United States regarding policy issues on electricity transmission systems. In that regard, he is currently the president of WIRES (Working group for Investment in Reliable and Economic Electric Systems), an industry coalition that promotes the development of an economic and robust high-voltage transmission grid. Mr. McCoy earned a Bachelor of Science in electrical engineering from the Illinois Institute of Technology, and is a licensed professional engineer in the state of Illinois.

Douglas Mitchell, Q.C.

Director

Mr. Mitchell helped to lead the national merger resulting in the law firm of Borden Ladner Gervais LLP (BLG) and is BLG's National Co-Chairman. He serves on a number of corporate boards and community organizations. He is the past Chair of the Calgary Chamber of Commerce and the Alberta Economic Development Authority.

Patricia Nelson

Director

Ms. Nelson is the Chief Executive Officer of the Calgary Health Trust and a former Member of the Legislative Assembly for Calgary-Foothills. In her four terms with the Alberta legislature, Ms. Nelson served as Minister of Finance and Chair of the Treasury Board, preceded by her roles as Minister of Energy, Minister of Economic Development and Tourism, Minister of Government Services and Deputy Government House Leader. Ms. Nelson graduated from the University of Calgary with a Bachelor of Commerce degree and gained 15 years of finance related experience in the oil and gas industry prior to joining Alberta politics. She previously was controller of Sabre Energy Ltd. and Petroterra Natural Resources Ltd. and the manager of financial control with Suncor Inc.

Robert Turgeon

Director

Mr. Turgeon is Past President of Trans-Québec & Maritimes Pipeline Inc., a natural gas transportation business in Quebec. During his 16 year tenure as President, Mr. Turgeon directed the planning and development of major pipeline work in addition to guiding significant corporate restructuring. Mr. Turgeon holds a Bachelor of Commerce degree from Sir George Williams (Concordia) University and a Bachelor of Laws degree from the Université de Montréal.

MANAGEMENT TEAM

Scott Thon

President and Chief Executive Officer

In more than 25 years of power industry experience in Alberta, Scott has held a variety of senior positions in the electricity industry from operations and engineering to market design and financial management. Scott is a registered professional engineer who graduated with a Bachelor of Science in Electrical Engineering from the University of Saskatchewan. He is also a graduate of the Executive Program from the University of Western Ontario's Richard Ivey School of Business.

Scott is an active member in the Canadian Electricity Association (CEA) serving on the Board of Directors, Management Board and as the past-Chair of both the Association's Transmission Council and Environmental Commitment & Responsibility Program. He also serves as Chair of the Board of Governors for Bow Valley College and as the Vice Chair of the Board of Directors for the United Way of Calgary and Area.

Scott participates on the Board of Management for the Alberta Economic Development Authority and is a member of their Energy and the Environment Committee. Scott is also a member of the Canadian Athletic Foundation's Board of Trustees. In 2005, Scott was recognized by the provincial government with the Alberta Centennial Medal.

Joseph Bronneberg

Executive Vice President and Chief Financial Officer

Joe brings more than 30 years of financial experience to AltaLink, most notably from the energy and mining sectors in western Canada and internationally.

As Chief Financial Officer, Joe oversees all aspects of AltaLink's financial affairs, including financial reporting, internal control and treasury. Under his direction, AltaLink continues to optimize finance operations to fit the business needs of stakeholders through innovation and continuous improvement. AltaLink's finance team provides efficient, cost-effective transaction processing within a balanced framework that promotes financial discipline and corporate governance through integrity and business ethics.

Joe holds a Bachelor of Business Administration and Commerce degree from the University of Alberta and is also a graduate of the Ivey Executive Development Program. He is a member of the Institute of Chartered Accountants of Alberta and of the Financial Executives Institute.

Dennis Frehlich

Executive Vice President and Chief Operating Officer

As a registered professional engineer, Dennis has more than 20 years of experience in the electric industry with a career focus in transmission. In the past 10 years, Dennis has led various areas of the transmission business including operations, maintenance, asset management, engineering, and construction of transmission facilities within Alberta. Since 2002, Dennis has led AltaLink in these areas as Executive Vice President and Chief Operating Officer. His career experience includes engineering in the technical areas of power system engineering, reliability, and asset management with additional experience in other areas of the industry such as distribution, information technology and marketing.

Dennis is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA), an Executive Member of CIGRE (International Council on Large Electric Systems) Canada and of the Canadian Electricity Association, Transmission Council. Dennis is a longstanding supporter of the United Way, Foster Parents Plan and several other charitable organizations.

Leigh Clarke

Senior Vice President, External Engagement and General Counsel

Leigh has been extensively involved in the Alberta electricity industry since the early 1990s. As a member of AltaLink's senior management team, he is responsible for leading AltaLink's stakeholder engagement programs, its corporate communications and government relations functions as well as the legal risk management programs and governance practices.

Upon graduating from the University of Alberta in 1991, Leigh was called to the Alberta bar in 1992 and acted as regulatory counsel to TransAlta from that time until 1999. Leigh was also seconded to the law branch of the National Energy Board where he handled gas and electricity facilities applications. Leigh is a member of the Canadian Public Relations Society and a member of the Conference Board of Canada's Council of Public Affairs Executives.

Zora Lazic

Senior Vice President, Regulatory and Client Services

With more than 20 years experience in various areas of the electricity industry, Zora's background involves work with a major Canadian utility, a power marketer, an Independent System Operator, and energy crisis management for a state agency with responsibility for markets, external affairs, contracts, compliance, regulatory and legal matters both in the regulated and deregulated side of the industry. Zora holds a Masters of Law from Cambridge University (UK) and degrees in Civil Law (B.C.L.) and Common Law (LL.B.) from McGill University.

Duane Lyons

Senior Vice President, Business Development

Duane has been extensively involved in various aspects of the electric power industry in Alberta and internationally for more than 40 years. As Senior Vice President of Business Development, Duane is responsible for leading AltaLink's growth initiatives and has been heavily involved in evaluating appropriate alternatives to meet Alberta's future transmission demands. Prior to joining AltaLink, he led the development of numerous energy projects in Canada, Mexico, Australia, New Zealand and the United States.

Duane holds a Bachelor of Science in Electrical Engineering from the University of Saskatchewan, and is also a graduate of the Executive Program of the School of Business from the University of Western Ontario. Duane is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta (APPEGA).

Linda Shea

Senior Vice President, Human Resources

With more than 20 years experience as a member of several senior management teams in the oil and gas and telecommunications industries, Linda has an extensive background in human resource management, organizational change and effectiveness, leadership development, and mergers and acquisitions.

Linda holds a Bachelor of Arts from Mount Allison University in Sackville, New Brunswick and a Master of Science in Organizational Development from American University, Washington, DC.

Johanne Picard-Thompson

Senior Vice President, Projects

Johanne has more than 25 years of experience across multiple industry sectors and brings a wealth of experience to AltaLink, having lead business improvement strategies across Canada, the United States, Mexico and Brazil. Prior to joining AltaLink, Johanne was the General Manager, Oil Sands Growth Operations at Shell Canada and was responsible for overseeing the operations, commissioning and startup planning for expansion projects.

Johanne is an engineering graduate from the University of Toronto and has served on NAIT's Advisory Board for the Shell Manufacturing Centre. She was named one of Canada's "Top 40 under 40" in The Globe and Mail's 2001 Report on Business for her leadership in growing Celestica's Canadian Operations by more than 80 per cent in a single year.

CORPORATE INFORMATION

Directors

David Tuer [1,3]
Chairman of the Board

Michael Bernstein [2]
Director

Jack Bittan
Director

Jim Burke
Director

Gilles Laramée [2]
Director

Paul McCoy [2]
Director

Douglas Mitchell Q.C. [2]
Director

Patricia Nelson [1,3]
Director

Robert Turgeon [1,3]
Director

Committee Members

[1] Audit
[2] Human Resources and Governance
[3] Environmental, Health and Safety

Executives

Scott Thon
President and Chief Executive Officer

Joseph Bronneberg
Executive Vice President and Chief Financial Officer

Dennis Frehlich
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Leigh Clarke
Senior Vice President, External Engagement and General Counsel

Zora Lazic
Senior Vice President, Regulatory and Client Services

Duane Lyons
Senior Vice President, Business Development

Linda Shea
Senior Vice President, Human Resources

Johanne Picard-Thompson
Senior Vice President, Projects

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Deloitte & Touche LLP

Legal counsel

Borden Ladner Gervais LLP

ALTALINK

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