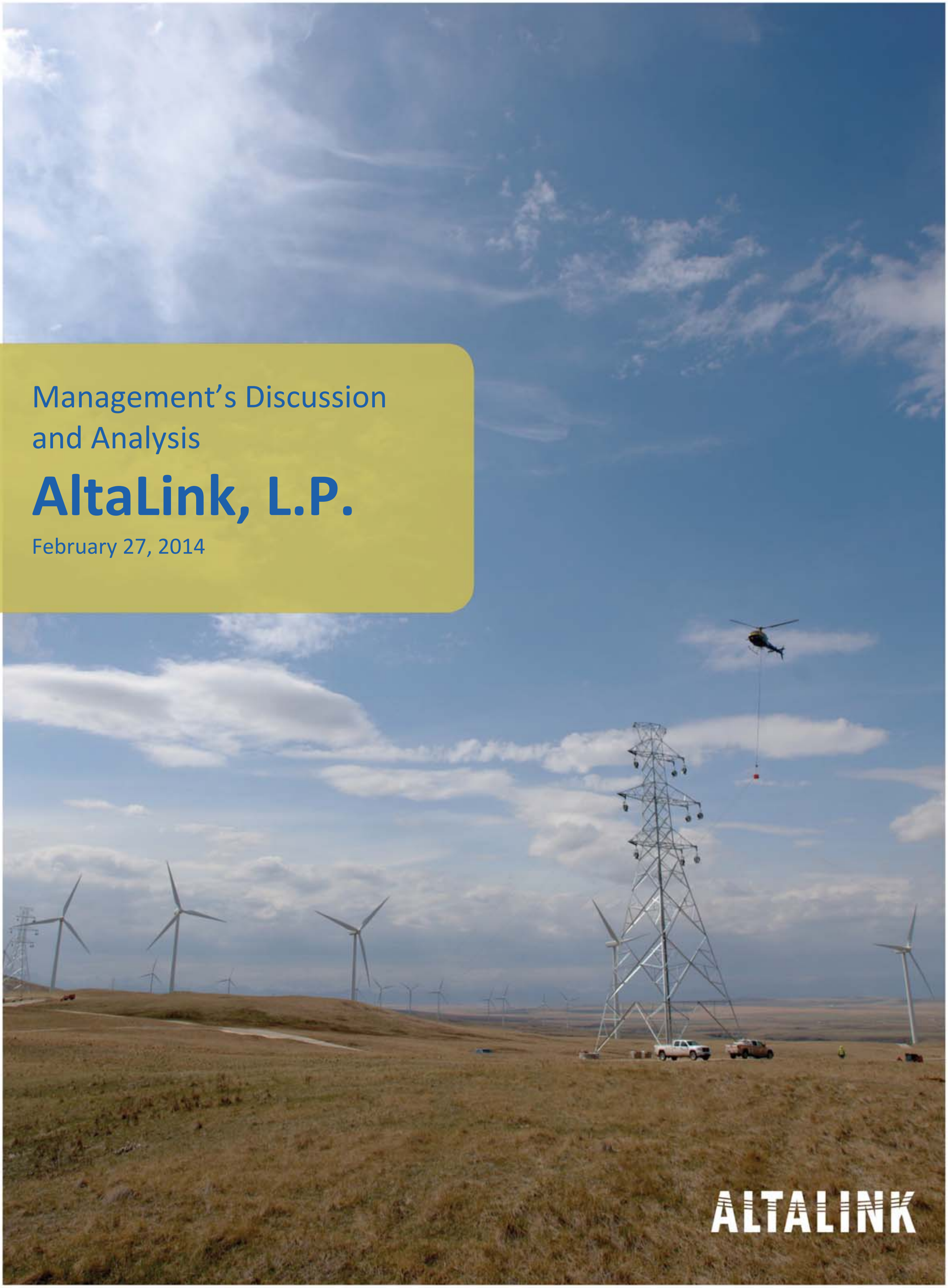
Management's Discussion and Analysis

AltaLink, L.P.

February 27, 2014



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Management's Discussion and Analysis

This Management's Discussion and Analysis (MD&A) reflects events known to us as of February 27, 2014. 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 27, 2014, based on the recommendation of our Audit Committee, which reviewed this MD&A in accordance with its terms of reference.

You should read this MD&A in conjunction with our legal advisory on Forward Looking Information, which we have included at the end of this MD&A, as well as our audited financial statements for the years ended December 31, 2013 and 2012 (the Financial Statements) and the notes thereto.

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

Unless otherwise noted, references in this MD&A to "we", "us", "our", "AltaLink" or "the Partnership" mean AltaLink, L.P. and references to a "quarter" and "year" refer to the three-month and twelve-month periods ended December 31, 2013, respectively. References to "AESO" mean Alberta Electric System Operator; "AUC" mean Alberta Utilities Commission; "CEA" mean Canadian Electricity Association; "CWIP" mean Construction Work-In-Progress; "GTA" mean General Tariff Application"; "GCOC" mean Generic Cost of Capital; "IFRS" mean International Financial Reporting Standards; "SNC" mean SNC-Lavalin Group Inc.; and "ATP" mean SNC-Lavalin ATP Inc.

Additional information relating to our business including our Annual Information Form for the year ended December 31, 2012 is available on SEDAR at www.sedar.com.

Executive Summary

2013 Highlights

- We invested $1,720.5 million (2012 - $974.7 million) in capital projects to significantly reinforce and expand the transmission system, providing service to Albertans;
- We issued $1,225.0 million of long-term senior debt to finance our capital program;
- We earned comprehensive income of $164.4 million (2012 - $107.0 million);
- We became the first electricity transmission utility in Canada to be designated as a Sustainable Electricity Company™ by the CEA; and,
- We put into service more than $1.4 billion of capital projects, including the Heartland, Cassils-Bowmanton, and Hanna projects.

Our Business and Strategies

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

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

Safe, Reliable and Cost-Effective Operations

We strive for excellence in our operating, maintenance and capital investment practices. We are committed to operating our transmission facilities efficiently and reliably and to protecting the safety of our employees, the public and the environment. We use life-extension and long-term asset replacement programs to replace facilities when they reach the end of their useful lives. For more information about our actual performance in this area, please see the section titled How We Measure Our Performance in this MD&A.

Expanding our Transmission Network

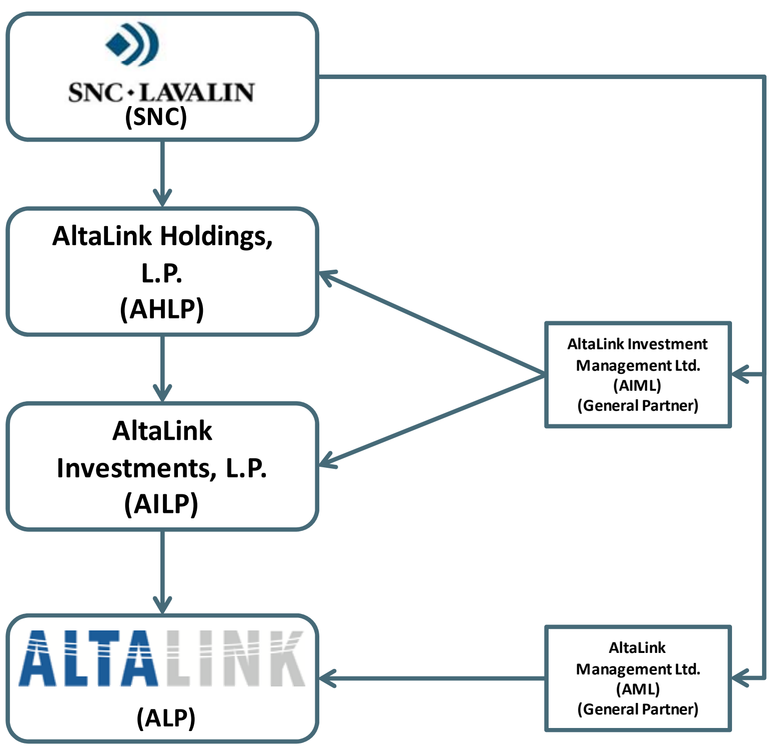
We are focused on keeping the lights on for Albertans and are committed to reinforcing Alberta's transmission infrastructure to ensure that the province's electricity grid can enable future prosperity. Although we grow and expand our transmission network primarily by constructing new transmission facilities, we are always searching for innovative methods to get more out of the existing grid, such as extending the life of the existing assets, re-using existing facilities and implementing new technologies. We will investigate and assess any future opportunities to acquire existing regulated electricity transmission assets in Alberta. For more information about our actual performance in this area, please see the Major Capital Projects section of this MD&A.

Stakeholder Engagement

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

Our Partnership Structure

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



On September 30, 2013, SNC announced it had initiated a process to sell up to 100% of its equity stake in AltaLink, as part of its strategic plan to reconfigure and rebalance its ownership in principal assets within its Infrastructure Concession Investments portfolio. Any change in our ownership structure requires the approval of the AUC. We expect SNC to make a decision regarding the proposed sale during 2014, and to seek regulatory approval from the AUC in a timely fashion.

Our Capability to Deliver Results

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

Financial Strength

We align our financing strategy with the regulated capital structure approved by the AUC and with targets for our key financial metrics. We finance our operations and maintenance capital expenditures from operating cash flows. We intend to fund the growth in capital expenditures from the balance of our operating cash flows, additional borrowings under our capital markets platform, and equity contributions from our limited partner, AILP. SNC is the indirect owner of AILP, and we expect SNC to continue to provide solid financial sponsorship and to contribute the additional equity needed to finance the capital investments we expect to make in the future. We do not expect the proposed sale to adversely affect our financial strength.

Operations

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

Capital Project Execution

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

In 2012, we completed a competitive bidding process and entered into five-year contracts with Burns and McDonnell Canada Ltd. and ATP, to provide EPCM services for future capital projects. All projects that had reached the proposal to provide service stage, as submitted to the AESO, prior to April 2012 are continuing to be executed by ATP under the previous contract.

Organizational Leadership and People

From January 21, 2013 until February 28, 2014, Scott Thon, our Chief Executive Officer was seconded to SNC-Lavalin Inc. During that time, he has not been involved in the management of AltaLink, and served as a member of our Board of Directors during this period. Our Chief Operating Officer, Dennis Frehlich, has been acting as interim President and Chief Executive Officer during this period. Effective March 1, 2014, Mr. Thon will resume his duties as Chief Executive Officer and will continue to serve as a member of our Board of Directors.

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

We strive continuously to enhance programs to attract, retain and develop a high quality workforce to enable us to not only sustain our business, but to remain at the forefront of innovation and continuous improvement. We employ over 800 skilled and dedicated people and are continuing to increase our workforce to deliver on the major transmission projects planned in Alberta.

On September 23, 2013, we asked our employees to complete an employee engagement survey, and 95% of our employees responded. Our employee engagement score was 83%. Compared to Mercer's normative data for Canada, we are in the top 10 percent of Canadian companies for employee engagement.

Environmental Leadership

We provide environmental leadership through innovative practices and sound risk management. In designing and constructing new transmission facilities, we consider ways to reduce land use impacts and improve efficiency. We strive to be leaders in environmental best practices.

We have been designated as a Sustainable Electricity Company™ by the CEA. With this designation, we became the first-ever transmission utility and second major electricity utility in Canada to earn this seal of approval of our sustainability efforts.

The CEA established the Sustainable Electricity Company™ designation in February, 2009 for electricity utilities across Canada. To obtain the designation applicants must meet several criteria, including a commitment to fully meet ISO 14001 standards for Environmental Management Systems, adherence to ISO 26000 guidance on Social Responsibility, and transparency of reporting of annual sustainability performance. In addition, we passed a third party external verification to ensure adherence to the sustainability criteria. Obtaining the Sustainable Electricity Company ™ designation is a reflection of our commitment to meeting the needs of our stakeholders, communities and employees through sustainable business practices.

How We Measure Our Performance

Delivering Customer Value

We use certain key measures to determine whether we are meeting our goals and the needs of our customers. As noted below, during 2013 our performance continued to compare favourably to other transmission facility owners in Canada for reliability, safety and cost effectiveness.

Reliability

We have a long-term trend of improving reliability through proactive operating practices and capital investment. Our reliability statistics are consistently better than those of our peers, as reported by the CEA.

We operate our transmission system so as to minimize disruption of service to our customers. Nevertheless, severe weather and other unplanned events cause service disruptions to which we respond as quickly as possible. During the twelve months ended December 31, 2013, the duration of service disruptions increased slightly from record levels achieved in 2012, as noted in the table below. In the same period, we decreased the frequency of service disruptions compared to the preceding twelve-month period. During the twelve months ended December 31, 2012, we reduced the duration of service disruptions, as noted in the table below. We also decreased the frequency of service disruptions compared to the preceding twelve-month period.

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

	Twelve months ended		
	December 31, 2013	December 31, 2012	December 31, 2011
Duration of outages (SAIDI) [1]			
AltaLink	**0.83**	0.61	0.73
CEA [3]	**N/A**	1.11	1.11
Frequency of outages (SAIFI) [2]			
AltaLink	**0.62**	0.78	1.04
CEA [3]	**N/A**	1.74	1.53

1. System Availability Interruption Duration Index is the average number of interruption hours per delivery point during a twelve-month period.
2. System Availability Interruption Frequency Index is the average number of interruptions per delivery point during a twelve-month period.
3. Statistics from the CEA are provided on a transmission only basis. The CEA results are not yet available for 2013.

Safety

Our safety management initiatives encompass all aspects of our safety systems, and our safety statistics are consistently stronger than our peers. Our safety statistics include all man-hours worked by contractors and sub-contractors. During the twelve months ended December 31, 2013, our workplace Injury Frequency Rate improved significantly compared to the preceding twelve month period. Our exposure hours have doubled in 2013 as compared to 2012, and tripled compared to 2011. During 2012 our workplace Injury Frequency Rate remained at approximately half of our peers in Canada. We strive to continuously improve our safety performance through focused training and our ongoing commitment to our safety culture and safety management processes.

		Twelve months ended	
	December 31, 2013	December 31, 2012	December 31, 2011
All injury frequency rate (AIFR)[1]			
AltaLink	**0.76**	1.03	0.61
CEA [2]	**N/A**	1.77	2.02

1. Number of lost time accidents and medical aid incidents per 200,000 man hours worked by employees and contractors.
2. Statistics from the CEA are provided on a transmission-only basis, and are for employees only. The CEA results are not yet available for 2013.

Cost Effectiveness

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

Financial and Operational Performance

Transmission Tariffs

We recognize revenue based on transmission tariffs approved by the AUC, including adjustments arising from deferral accounts established under those tariffs.

In our 2013-2014 general tariff application, we requested approval from the AUC for increases in our revenue requirements of $491.7 million and $636.2 million for 2013 and 2014 respectively, primarily due to our continued investment in capital projects as directed by the AESO. On November 12, 2013, the AUC issued Decision 2013-407 approving the majority of our requested revenue requirement. We submitted a compliance filing as directed by the Commission in Decision 2013-407 on January 15, 2014, requesting approval of a revenue requirement of $481.3 million and $621.4 million for 2013 and 2014, respectively. On February 26, 2014, in Decision 2014-046, the AUC increased our monthly interim tariff, effective March 1, 2014, enabling us to collect the majority of the requested revenue requirement for 2013 and 2014 applied for in the compliance filing.

In 2012, the AUC issued several decisions related to our transmission tariff revenue for 2011 and 2012. On January 30, 2013, the AUC issued Decision 2013-023 approving our compliance filing, which finalized our transmission tariffs for 2011 and 2012.

In Decision 2011-474, the Commission approved an increase of 1% in our common equity ratio and reduced the generic rate of return on common equity to 8.75% from 9%. The Commission has established a process schedule for review of the GCOC for 2013 and 2014, with an oral hearing scheduled for May 26, 2014. In doing so, the Commission has directed a placeholder of 8.75% for 2013 and 2014 return on common equity, pending a final decision as part of the announced GCOC proceeding.

Growth in Regulated Capital Assets

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

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

Mid-year rate base and construction work in progress	**2013**	2012	2011
(in millions of dollars)			
Mid-year rate base	**$ 2,485.9**	$ 1,781.6	$ 1,552.2
Mid-year construction work in progress	**1,159.1**	794.0	397.3

In the compliance filing for our 2013 – 2014 GTA, we have forecast our 2014 gross direct assigned capital expenditures to be $1.7 billion. Our actual capital program may vary from our regulatory filings, depending on the timing of regulatory approvals, directions from the AESO, and other factors beyond our control. In particular, certain developments that we discuss in the Major Capital Projects section of this MD&A may materially impact our capital expenditure outlook. On January 31, 2014, the AESO released an update to its long range capital plan. We are currently evaluating the impact of this plan on our forecast capital expenditures.

Regulated Tariff Revenue

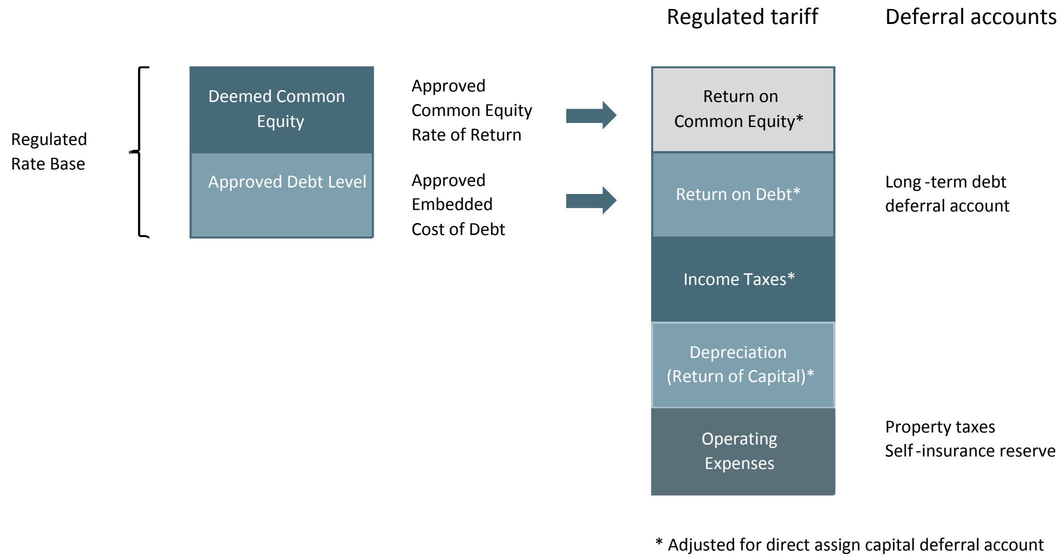
We are an electric utility regulated by the AUC, pursuant to the Electric Utilities Act (Alberta), the Public Utilities Act (Alberta), the Alberta Utilities Commission Act (Alberta) and the Hydro and Electric Energy Act (Alberta). Through various regulatory decisions, these statutes and their respective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

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

Overview of Our Transmission Tariffs

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

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



Return on Rate Base and Allowance for Funds Used During Construction

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

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

General Tariff Application and Transmission Tariffs for 2013 and 2014

During 2013 the AUC issued Decision 2013-407 with respect to our GTA for 2013-2014. On January 15, 2014 we filed our compliance filing to give effect to the Commission's directives included in Decision 2013-407 and Decision 2013-459, which directed a placeholder return on equity of 8.75% for 2013 and 2014, pending the GCOC decision.

In Decision 2013-407, the AUC did not approve for inclusion in our forecast capital project expenditures in 2013 and 2014, the rates for engineering, procurement and construction management ("EPCM") services resulting from the Competitive Procurement Process ("CPP"). The AUC directed us to re-forecast the capital project expenditures for such EPCM services to reflect a two times labour multiplier and other approved mark-ups. We plan to seek approval of the capital project expenditures, including the new competitively bid EPCM rates, in a future DACDA proceeding. We have applied to the Alberta Court of Appeal for Leave to appeal Decision 2013-407.

In recent tariff and cost of capital decisions, the AUC stated that it was in the best interests of ratepayers for us (and other transmission facility owners) to maintain our current credit ratings. The AUC affirmed its support by approving certain measures to maintain our credit metrics in anticipation of significantly higher capital expenditures which we expect to finance over several years. We attribute the increases in capital expenditures largely to new asset construction projects that we expect the AESO to directly assign to us. As outlined in the Major Capital Projects section of this MD&A, the AUC has approved facility applications for more than $5.5 billion (including Cassils Bowmanton Whitla, Heartland, WATL and FATD projects). In addition, we have filed

$904 million of facility applications for which we expect AUC decisions in 2014.

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

In Decision 2011-453, the AUC approved credit metric relief for our 2011 and 2012 transmission tariffs in the form of (i) the continuation of the future income tax method for federal income taxes and (ii) the use of CWIP in Rate Base. In Decision 2013-407 pertaining to our 2013-2014 GTA, the Commission approved the continuation of the existing credit metric relief for 2013, and 2014, and provided additional relief in the form of approving the use of the future income tax method for calculating the recovery associated with provincial income taxes.

Generic Cost of Capital

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

In Decision 2011-474, which was effective January 1, 2011, the AUC decreased the generic rate of return on common equity applicable to all utilities to 8.75% from the previously approved rate of 9.00%. In addition, the AUC increased our common equity ratio from 36% to 37%. The approved common equity ratio and generic rate of return on common equity will remain in effect until changed by the AUC. In 2012, we and other utilities regulated by the AUC applied to the Alberta Court of Appeal for Leave to Appeal, based on, among other things, the AUC's finding that utilities bear the risk of stranded assets. This matter is set to be heard on April 17, 2014.

We and other utilities regulated by the AUC applied to the AUC for Review and Variance (R&V) of Decision 2011-474. On June 4, 2012, the AUC issued Decision 2012-154, rejecting the R&V application on the basis that its statements regarding stranded asset risk were unnecessary for the AUC to make a determination of the issues. The AUC then held that issues relating to stranded asset risk should be evaluated in a broader Utility Asset Disposition Proceeding.

Subsequent to issuing Decision 2013-417 regarding the Utility Asset Disposition Proceeding, the AUC issued a revised process schedule regarding the 2013 GCOC proceeding that reflects a tentative oral hearing date of May 26, 2014, with a final decision expected in the fourth quarter of 2014.

Utility Asset Disposition Proceeding

On November 26, 2013 the AUC issued Decision 2013-417, in which it determined that certain losses or gains related to asset dispositions are to be borne by the shareholders. The AUC did not direct any changes with respect to retirements in the ordinary course of business. However, they directed that the costs of all assets that are no longer used and useful must be removed from rate base and any under or over recovery of costs related to extraordinary retirements are to be borne by the utility.

We and other utilities regulated by the AUC filed a Leave to Appeal with the Alberta Court of Appeal on December 23, 2013 regarding Decision 2013-417 on the grounds that the AUC erred, among other things, by failing to apply the express statutory standard applicable to Transmission Facility Owners with regard to the process for removing assets from rate base that are no longer used or required to be used in the provision of utility services.

The appeal regarding the Utility Asset Disposition Decision 2013-417 is expected to be heard in conjunction with the appeal on the GCOC Decision 2011-474 on April 17, 2014.

Deemed capital structure and generic returns	Interim 2013	Approved 2012	Approved 2011
Deemed capital structure			
Common equity ratio	**37.00%**	37.00%	37.00%
Debt ratio	**63.00%**	63.00%	63.00%
Generic returns			
Return on equity	**8.75%**	8.75%	8.75%

Transmission Tariffs

The table below summarizes the 2013 and 2014 tariff filed by us in our 2013-2014 GTA Compliance Filing, which was submitted on January 15, 2014, in accordance with the AUC's directions in Decision 2013-407:

(in millions of dollars)	2014 Compliance filing	2013 Compliance filing	2012 Approved
Return on equity	$ 159.0	$ 113.5	$ 83.7
Return on debt	128.0	97.1	83.0
Operating costs	129.5	112.9	104.4
Miscellaneous revenue	(7.6)	(7.5)	(7.6)
Depreciation and amortization	157.5	125.5	104.3
Income taxes	55.0	39.7	20.3
Revenue requirement	**$ 621.4**	**$ 481.3**	**$ 388.1**

**Totals may not add due to rounding*

In Decision 2013-024, dated January 31, 2013, the AUC approved an interim refundable revenue requirement of $455.8 million for 2013. On January 15, 2014, we submitted an application to the AUC seeking approval for the collection of an increased interim refundable revenue requirement of $646.9 million for 2014. As noted above, we received their decision on February 26, 2014, in which they approved collection of most of the amount requested in the application.

The forecast revenue requirement is based on our January 15, 2014 compliance filing, which includes our estimates of the impact of the Commission's directives in Decision 2013-407, including the continuation of the credit metric relief approved in Decision 2011-453, together with the additional relief of allowing us to use the future income tax method for calculating the recovery of deemed provincial income taxes. Please refer to the Regulatory Financial risk section in this MD&A for more information.

Operating expenses

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

Taxes Other Than Income Taxes

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

Depreciation and Reserve for Salvage Costs

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

Income Taxes

As a limited partnership, we do not pay federal or provincial income taxes directly. Income taxes related to our operations are paid by the corporations owned by SNC-Lavalin that hold partnership interests in AHLP. Our transmission tariffs include recovery of income taxes that the AUC deems we would have paid in connection with our regulated operations if we were a tax paying entity. The AUC approves our collection of these amounts as the corporate owners of AHLP are obliged to pay these amounts to the tax authorities. In Decision 2011-453, the AUC directed us to continue to use the future income tax method for calculating deemed federal income taxes. In Decision 2013-407, the AUC also approved the use of the future income tax method for provincial income taxes for 2013 and 2014 revenue requirements.

In the future, the AUC may direct us to stop using the future income tax method for federal and provincial income taxes and provide options for the disposition of the accumulated future income tax balances. The amounts of future income taxes received to date are deducted from rate base in calculating our revenue requirement.

Our Transmission Facilities

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

Our transmission facilities are an integral part of the AIES. We own approximately 12,500 kilometres of transmission lines and 290 substations which we manage and operate through our control centre and extensive telecommunications network. Our transmission lines are comprised of wood or metal support structures, conductors, foundations, insulators, connecting hardware and grounding systems. Our substations are comprised of high-voltage power transformers, power circuit breakers, switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems, buildings and security systems. Our substations integrate the transmission lines into a network and transform the voltage of electricity to meet the requirements of generators and customers. We generally accept electricity into our system at our generator interconnection substations and deliver power to distribution facility owners and wholesale customers at our customer supply substations. Where the transmission system connects to a distribution network, transmission substations step down the voltage to distribution level voltages.

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

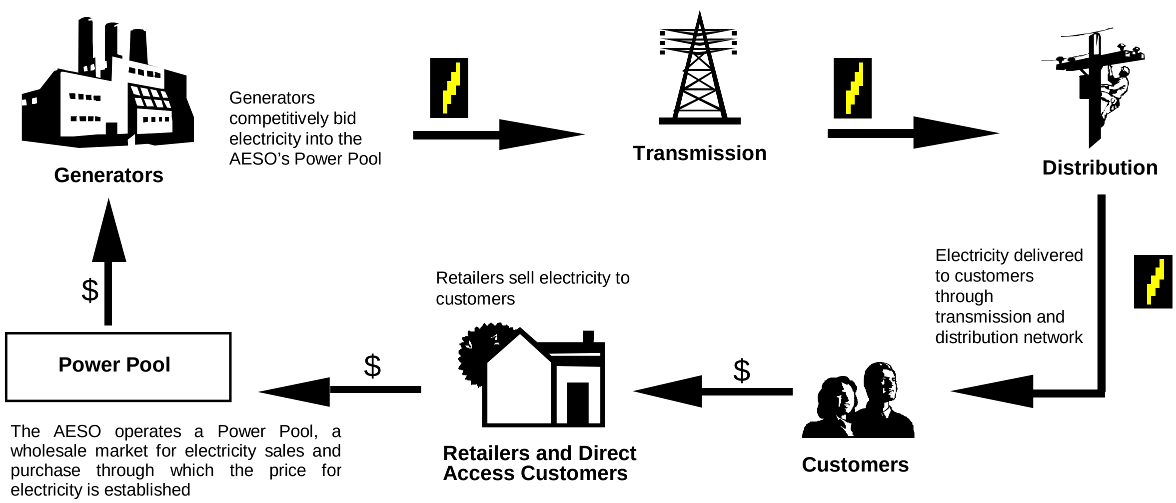
Most of our transmission facilities are situated on lands owned by private landowners, railway companies, industrial customers, and federal and provincial governments, for which we have obtained appropriate land use rights through utility right-of-way agreements, crossing agreements, leases, permits,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

Overview of Electricity Industry in Alberta

The electricity industry in Alberta consists of four principal segments:

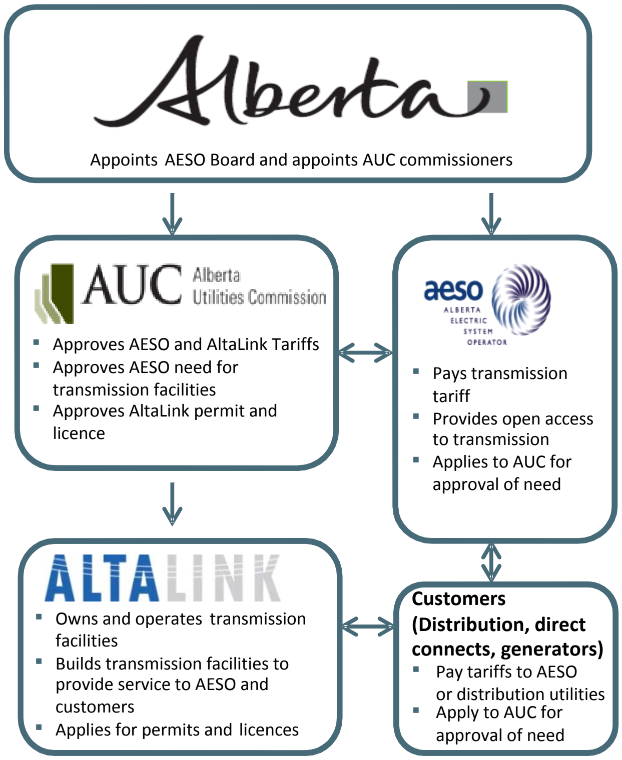
- Generation is the production of electric power. Generators sell wholesale power into the power pool operated by the AESO or through direct contractual arrangements. Most of the power produced in Alberta is generated using coal or natural gas as the fuel source with hydro and wind power adding the majority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

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



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

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



Alberta Utilities Commission

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

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

Alberta Electric System Operator

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

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

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

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

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

- Customer Rates - All end-users (or load customers) are charged the same "postage stamp" tariff for transmission service, regardless of where they are located in Alberta.
- Supplier Rates - All suppliers are charged the same "postage stamp" tariff for transmission service in addition to an adjustment for losses which are location specific.
- Import/Export Rates - All importers or exporters are charged the same "postage stamp" tariff for transmission service in addition to an adjustment for losses which are location specific.

Alberta Reliability Standards

The AESO continues to introduce mandatory reliability standards for planning and operating the AIES and its interties to other jurisdictions. Several new cyber security standards will come into effect over the next several years. We are working closely with the AESO in preparations for the introduction of these new standards. Reliability standards are the planning and operating rules that electric utilities follow to ensure reliable systems.

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

Transmission Planning and Development

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

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

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

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

Cost Estimates

Prior to filing a facility application with the AUC, we provide the AESO with a proposal to provide service that includes our initial cost estimate for the project, which reflects our proposed route, preliminary design and other information available to us at the time.

After the AESO accepts our proposal to provide service, we include the initial cost estimate as part of our facility application with the AUC. The AUC's process to review and approve facility applications may take up to two years from the date of filing, depending on the complexity of the project and other factors. Six months after the AUC issues a permit and licence pursuant to an approved facility application, we are required to provide the AESO with an updated cost estimate. The timing of the updated cost estimate may be as long as three years after our proposal to provide service and may vary materially from the initial cost estimate. The updated cost estimate reflects a significant amount of additional information that typically includes the AUC's approved route, contracted construction labour and material pricing, geotechnical information, scope changes from detailed design, and any other material information that may impact the final project cost.

Once the project is completed, we include the final costs in our direct assign capital deferral account application to the AUC where we seek approval to include our final and prudently incurred costs of the project into our rate base.

Critical Transmission Infrastructure

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

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

On January 17, 2014, the AESO announced that five qualified organizations will compete for the opportunity to build, finance, own and operate a major component of Alberta's transmission infrastructure from the Wabumun to the Fort McMurray area (Fort McMurray West) under the newly created competitive process. Fort McMurray West is the first project launched under the AESO's competitive bid process. Fort McMurray West will consist of approximately 500 kilometres of 500kV transmission line and associated facilities and is needed to support increasing growth in northeastern Alberta.

The five qualified organizations selected to bid include Athabasca Transmission, which is owned by us and AEP Transmission Holding Company LLC (AEP). We have entered into an agreement with AEP to participate in the competitive process. In late 2014, Athabasca Transmission plans to submit a proposal to the AESO to develop, design, construct, own, operate and maintain the Fort McMurray West project.

Major Capital Projects

The AESO's 2011 Long Range Transmission System Plan identified the potential for $13.5 billion in existing and proposed transmission development projects over the next ten years, to ensure a reliable supply of electricity in Alberta. In addition to the transmission projects for which the AESO has filed a need application, the ten-year transmission system plan also identified additional transmission facilities that could be required depending on how power generation and demand scenarios unfold, including a number of regional upgrades.

We expect to develop a significant portion of the plan, as either or both of the AESO's need applications and our facility applications have been filed with the AUC. After the AUC approves our facility applications, we are responsible for constructing and operating the related transmission facilities.

The AESO released an updated Long Range Transmission System Plan on January 31, 2014. We are currently evaluating the impact of this plan on our forecast capital expenditures.

Overview

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

Project/ Description	Need Application	Facility Application	Status
Southern Alberta Transmission Reinforcement Large scale project to construct transmission lines and substations across southern Alberta to interconnect up to 2,700 MW of proposed wind generation projects. **Stage I**	AUC approved in 2009	• All applications approved.	• Cassils-Bowmanton energized in 2013 and Bowmanton to Whitla scheduled for 2014 completion. • South Foothills scheduled for 2015 completion.
Stage II	AUC approved in 2009	• Medicine Hat 138kV Transmission Project approved in Q4, 2013. • Multiple applications planned in 2014.	• Construction scheduled for 2015 completion. • Preparing facility applications
Western Alberta Transmission Line Reinforce system backbone between Edmonton and Calgary with a HVDC transmission line and converter substations.	CTI designation in 2009	• Approved in 2012.	• Construction scheduled for 2015 completion.
Heartland Region Transmission Development Double-circuit 500kV transmission line between the Ellerslie Substation and a new substation in the Gibbons-Redwater area and 240kV loop from the new substation to service industrial load.	CTI designation in 2009	• Approved in 2011.	• Energized in 2013 at 240kV. Energization at 500kV scheduled for 2014.
Edmonton Region Transmission System Upgrade Debottleneck 240kV system for load growth and decommissioning of coal-fired generation.	AUC approved in 2009	• All applications approved.	• Construction scheduled for 2014 completion.
Foothills Area Transmission Development Expand and construct substations and transmission lines in south Calgary region to reinforce local transmission and further interconnect wind energy into the AIES.	Filed in July 2012	• All applications approved in October, 2013.	• Construction scheduled for completion in 2015.
Hanna Region Transmission Development Reinforcements and enhancements of the transmission system in southeastern Alberta.	AUC approved in 2011	• All applications approved.	• All three projects energized in 2013.
Christina Lake Area Development Construction of 240kV transmission line and substations in the Christina Lake area to meet forecasted load growth.	AUC approved in 2012	• Three applications approved.	• One project completed in 2013. • Remaining projects scheduled for completion in 2014 and 2015.
Red Deer Region Transmission Development Reinforcement and enhancements of the transmission system in the central Alberta region.	AUC approved in 2012	• One application approved. • Two applications filed in Q2, 2013. • Two additional applications planned for 2014.	• Completed. • Awaiting AUC hearing for applications under review.

CTI – Critical Transmission Infrastructure

Southern Alberta Transmission Reinforcement (SATR)

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

In 2009, the AUC approved the AESO's need application for a comprehensive reinforcement of the transmission system in southern Alberta, to be constructed in several stages. Stage I will enable the interconnection of proposed wind generation facilities capable of producing at least 1,200 MW. Subsequent development of Stage II is expected to further reinforce the system, consistent with the AESO's growth forecast for wind generation facilities in the region. The AESO has determined that SATR III is no longer needed and has cancelled this stage.

We expect the total cost for Stages I and II of the SATR project to be approximately $2.5 billion.

Stage I

SATR I consists of five projects. Milo and Russell were energized in 2011. In 2013, we completed construction on the Cassils to Bowmanton facilities ahead of schedule. We continue to construct the Bowmanton to Whitla facilities, which are scheduled for completion in the first quarter of 2014 The South Foothills Transmission Project was approved in 2013 and we began construction in the fourth quarter of 2013. We expect to complete this project in 2015. We have estimated the total costs of Stage I to be $1.1 billion. As at December 31, 2013, we have spent $730.6 million (December 31, 2012 - $545.0 million).

SATR II consists of five major lines projects and four smaller projects. We estimate that the projects will cost $1.5 billion. The Medicine Hat 138kV Reconfiguration facility application was approved by the AUC in October 2013 and construction has commenced. The AESO requested we delay the filing of our facility applications for Goose Lake to Etzikom Coulee, Etzikom Coulee to Whitla and Picture Butte to Etzikom Coulee until 2014, pending an analysis related to the intertie restoration initiative. As at December 31, 2013, we have incurred capital expenditures of $81.5 million.

Western Alberta Transmission Line

On December 6, 2012, the AUC approved our facility application to construct 350 km of high voltage direct current transmission line and two 1,000 MW converter stations in the Lake Wabamun area west of Edmonton and in the Langdon area east of Calgary. The AESO has extended the in-service date for this project to April 2015 due to extensive procedural delays leading up to the AUC's approval of the project. We have estimated the total costs of these facilities to be $1.7 billion. We began construction in 2013 and have spent $678.7 million as of December 31, 2013 (December 31, 2012 - $133.7 million).

Heartland Region Transmission Development

In 2010, we and EPCOR jointly applied for approval of 65km of 500kV transmission facilities along the east transportation utility corridor route, as that route crosses the service territories of both utilities. Concurrently, we also filed separate applications for certain facilities located entirely within our service territory, including the Ellerslie substation expansion, the Heartland substation, and 22km of 240kV transmission line to interconnect proposed industrial load within the Heartland region. The AUC approved all of these facility applications in November 2011. During 2013, we completed the first phase of construction and put the facilities into service at 240kV. We plan to complete the phased energization of the facilities to 500kV in 2014. As at December 31, 2013, our share of the costs related to this project totaled $400.7 million (December 31, 2012- $156.3 million).

In addition, In December of 2013, we filed an application with the AUC to partition the Heartland assets. This application requests that the AUC approve each utility owning its portion of the line within its transmission service area. We also requested a financial adjustment and to allocate the capital costs equally between ourselves and EPCOR for rate base purposes.

Edmonton Region 240kV Transmission System Upgrades

In February 2009, the AUC approved the AESO's Need Application to reinforce the transmission system in the Edmonton Area to debottleneck transmission capability, to change power system flows due to the retirement of Wabamun Unit #4, and to meet the increasing electrical demand in Edmonton and northeastern Alberta. We have completed all portions of the projects, except the portion that crosses First Nations land, which are owned by another utility from which we are waiting for direction to continue construction. We have estimated the total costs of these facilities to be $119 million. As at December 31, 2013, our total capital expenditures related to this project were $101.1 million (December 31, 2012 - $84.4 million).

Foothills Area Transmission Development

The Foothills Area Transmission Development project is an integral part of the system required to move wind energy to the load centres of the greater Calgary area. The scope of these developments includes various transmission line upgrades, replacements and modifications to existing substations as well as construction of a new Foothills substation. We have estimated the total costs of these facilities to be $413 million, with in-service dates planned for 2015. As at December 31, 2013, our total capital expenditures related to this project were $64.7 million (December 31, 2012 - $24.0 million). We received all permits and licences for this area development in November 2013 and have commenced construction.

Hanna Region Transmission Development

The Hanna Region Transmission Development consists of three projects that were energized in 2013. As at December 31, 2013, we have incurred capital expenditures of $291.9 million (December 31, 2012 - $125.0 million), with estimated final costs of $306 million.

Christina Lake Area Development

The Christina Lake Area Development consists of three projects, including a 240kV switching station interconnection, two new substations and approximately 100km of 240kV transmission line. One project was completed in 2013, and two projects are in construction, with in-service dates planned for 2014 and 2015. We have estimated the cost of these projects to be $424 million. As at December 31, 2013, we have incurred capital expenditures of $112.9 million (December 31, 2012 - $9.4 million).

Red Deer Transmission Development

The AUC approved the need for the Red Deer Area Transmission Development in 2012. The development includes five facility applications. One application has been approved and construction is complete. Two applications were submitted in 2013 and a hearing is scheduled for 2014. We plan to file the two remaining applications in 2014. Project estimates are approximately $400 million, with in-service dates ranging from 2013 – 2016. As at December 31, 2013, we have incurred capital expenditures of $69.5 million (December 31, 2012 - $33.3 million).

Environment, Health and Safety

Environmental Management System

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

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

- We continued having comprehensive environmental assessments completed by experienced environmental firms to support major project developments;
- We have engaged with provincial regulatory agencies to develop a streamlined Water Act approval process which will create regulatory approval efficiencies and have a positive impact on project timelines. We have piloted the proposed process on the Western Alberta Transmission Line;
- We spent approximately $9.5 million (2012 - $13.7 million) to manage environmental aspects of our business, including environmental assessments for new transmission facilities; and,
- We continued to demonstrate innovation in environmental protection technology by working with Cantega Technologies Inc. and installing their GREENJACKET® protective covers, which has dramatically reduced bird and other wildlife outages at our substations by 95%. We have completed the retrofit of approximately 90 substations to date, including 12 substations in 2013, and we are installing protective covers in approximately 10 substations per year.

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

Under our environmental management system, we identify, manage and mitigate key environmental risks and maintain regulatory compliance through our established operational standards and procedures. We support and enhance the effectiveness of our system through appropriate reporting, record keeping, training and audit processes. We have modelled our system after ISO 14001, the international standard for environmental management systems, and we have included five broad programs. We reviewed our system in 2013, as part of our cycle of continuous improvement and we plan to implement our revisions in early 2014.

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

Chemical & Spill Management

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

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

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

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

Land Management

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

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

Rights-of-Way Management

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

We use herbicides to control vegetation on rights-of-way and within substations. All herbicide use is completed by a licensed applicator as required by Alberta Environment and Sustainable Resources Development. We do annual inspections to monitor whether herbicide in any material quantity has migrated from our property or rights-of-way.

Treated Wood Management

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

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

Waste Management

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

We have developed a process to recycle large transformers, which typically are larger than a full sized pick-up truck and which may contain trace amounts of PCB. We collaborated with a specialized hazardous waste handling contractor to develop the process. These types of transformers are completely enclosed within a secure containment system during transportation. We ensure salvaged metals are clean of any trace amounts of PCB prior to recycling. In 2013, we recycled four large transformers and we anticipate that we will recycle another six transformers in 2014.

Electric and Magnetic Fields

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

We provide accurate and up-to-date information, including measurements, to the public upon request. During 2013, the volume of requests for information increased as a result of the extensive landowner consultations supporting our capital projects. To meet the needs of our stakeholders, we have increased the resources available to support these activities.

Health and Safety

Culture

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

Safety Codes

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

Non-GAAP Financial Measures

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

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

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

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

Financial Position

In the following table, we discuss significant changes (over $50.0 million) in our statement of financial position during the year ended December 31, 2013. Our annual audited Financial Statements include more detailed information regarding the changes in our property, plant and equipment.

	Increase/(Decrease) ($ Millions)	Explanation
Intangible assets (Note 6)	52.7	We added $68.1 million to construction work-in-progress, offset by $15.3 million in amortization.
Property, plant and equipment (Note 7)	1,662.0	We added $1,787.0 million to capital assets and construction work-in-progress, partially offset by $117.7 million in depreciation and $7.2 million of net asset retirements.
Third party deposits (Note 8)	55.6	We received $230.3 million from our customers to fund projects that we build on their behalf, and applied $174.7 million to such projects.
Trade and other payables (Note 10)	169.1	Trade payables increased due to the level of capital activity in 2013.
Long-term debt maturing in less than one year (Note 11(b))	(325.0)	We repaid $325.0 million of senior secured Bonds, as they matured on June 5, 2013.
Long-term debt (Note 11(b))	1,218.2	We issued $1,225.0 million of senior secured Medium-Term Notes to finance our capital expenditure program, and repay maturing debt.
Deferred revenue (Note 12)	162.4	We transferred $174.6 million of third party deposits and $18.8 million of funding for salvage costs into deferred revenue. We also recognized $16.1 million of revenue to fund salvage costs, and amortized $14.8 million of third party contributions.
Partner's equity (Note 19)	463.7	We received $337.5 million in equity injections from AILP and generated comprehensive income of $164.4 million. We distributed $38.2 million to our partners.

Liquidity and Capital Resources

Liquidity

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

The aggregate of our bank credit facilities at December 31, 2013 was $1.3 billion (December 31, 2012 - $1.5 billion). The $1.225 billion commercial paper backstop facility provides support to our commercial paper program. As at December 31, 2013, $42.5 million (December 31, 2012 – nil) of commercial paper was outstanding under our commercial paper program. All bank credit facilities may be used for general corporate purposes. As at December 31, 2013, we had $1.256 billion of liquidity remaining under those facilities. Our liquidity arrangements are considered adequate to accommodate our expected capital expenditures and working capital requirements over the next few years.

As at December 31, 2013, we have issued $1.5 billion (December 31, 2012 - $275 million) of Medium-Term Notes under our $2.5 billion Short Form Base Shelf Prospectus, which expires on December 9, 2014.

We plan to finance our projected capital investments, working capital requirements and any maturities of long-term debt through a prudent combination of cash flow from operating activities, new long-term debt, and equity contributions from AILP.

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

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

Liquidity Ratios [1]

	Year ended December 31,		
	2013	2012	2011
Interest coverage			
EBIT coverage [2, 3]	**2.80X**	2.48X	2.39X
EBITDA coverage [2, 4]	**4.28X**	3.87X	3.93X
FFO coverage [2, 5]	**2.79X**	2.71X	2.55X
Debt/total capitalization [6]	**60.22%**	57.20%	56.90%

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

Working Capital

At December 31, 2013, our working capital deficiency was $377.2 million, compared with $449.7 million at December 31, 2012. The working capital deficiency includes drawn bank credit, commercial paper and trade payables.

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

Cash Flows

	Quarter ended		Year ended	
	December 31, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
(in millions of dollars)				
Cash and cash equivalents, beginning of period	**$ —**	$ —	**$ 9.2**	$ 15.4
Cash flow provided by (used in):				
Operating activities	**(25.5)**	31.5	**309.2**	136.8
Investing activities	**(658.2)**	(325.0)	**(1,544.7)**	(846.4)
Financing activities	**689.6**	302.7	**1,232.2**	703.4
Cash and cash equivalents, end of period	**$ 5.9**	$ 9.2	**$ 5.9**	$ 9.2

Operating Activities

For the year ended December 31, 2013, our cash flow from operating activities increased by $172.4 million compared to the same period in 2012. The change is primarily due to an increase in net income, increase in the recovery of depreciation and amortization, increase in operating accounts payable and a decrease in accounts receivable as a result of lower regulatory accruals.

For the three months ended December 31, 2013, our cash flow from operating activities decreased by $57.0 million compared to the same period in 2012. This change is primarily due to an increase in accounts receivable as a result of higher regulatory accruals and the timing of GST refunds from the Receiver General, partially offset by increases in both net income and the recovery of depreciation and amortization.

Investing Activities

Compared to the same periods in 2012, our cash flow used in investing activities increased by $698.3 million and $333.2 million for the year and quarter ended December 31, 2013, respectively, primarily due to higher investment in new transmission facilities. We incurred most of our 2013 capital expenditures in connection with major capital projects that we discuss in more detail in the Major Capital Projects section.

Financing Activities

For the year ended December 31, 2013, cash flow provided by financing activities increased by $528.8 million compared to the same period in 2012. We issued $40.7 million of commercial paper and $1,225.0 million of long-term debt to repay $325 million of Senior Bonds and to finance our capital program. AILP contributed equity of $337.5 million and received distributions of $38.2 million from us. During the same period in 2012, we issued $575.0 million of long-term debt, used the proceeds to repay $85.0 million of subordinated debt and $17.2 million of commercial paper, received $270.8 million of equity, and distributed $36.5 million to AILP.

For the three months ended December 31, 2013, cash flow provided by financing activities increased by $386.9 million compared to the same period in 2012. We issued $500.0 million of long-term debt and used the proceeds to repay commercial paper and to finance our capital program. We also received $225.0 million of equity and distributed $8.8 million to AILP. During the same period in 2012 we received $121.0 million of equity, and distributed $10.0 million to AILP.

As most users of our Financial Statements find the information in the indirect method of computing cash flows useful, we have used this method to present our cash flow statement. In addition, as some users of our Financial Statements find the information in the direct method useful, we have included the direct method of presenting cash flows from operating activities below. There are no material differences in presentation of cash flow from investing and financing activities.

	Quarter ended		Year ended	
	December 31, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012
(in millions of dollars)				
Cash flows from operating activities				
Net receipts from AESO	**$ 113.9**	$ 85.1	**$ 524.6**	$ 311.5
Receipts from other third parties	**47.1**	30.8	**167.5**	88.1
Payments to suppliers and contractors	**(152.3)**	(47.2)	**(262.4)**	(156.5)
Payments to employees	**(8.2)**	(6.5)	**(42.6)**	(33.6)
Interest payments	**(26.0)**	(30.7)	**(77.9)**	(72.7)
Net cash provided by operating activities	**$ (25.5)**	$ 31.5	**$ 309.2**	$ 136.8

Earnings Coverage

	Year ended December 31,		
	2013	2012	2011
Earnings-to-interest coverage on total debt [1,2]	**2.02X[3]**	2.11X	2.08X

1. Earnings-to-interest coverage on total debt is a non-GAAP financial measure. As a result of distributing securities by way of a medium-term note program using the debt shelf procedures, we must include updated earnings coverage ratios in conjunction with our financial statements. Refer to "Non-GAAP Financial Measures" for further information concerning the non-GAAP financial measures used in this MD&A.
2. Earnings-to-interest coverage on total debt equals income before interest expense (including amortization of deferred financing fees) on all indebtedness and income taxes divided by annual interest requirements on long-term debt (including capitalized interest). We calculate this ratio by giving pro-forma effect to any long-term debt issued during the period and the use of the proceeds from such long-term debt issues.
3. Our interest requirement on short and long-term debt for the twelve months ended December 31, 2013 was $126.9 million (December 31, 2012 - $85.5 million; December 31, 2011 - $70.7 million), including the pro-forma effect of interest payable on the Series 2013-1, 2013-2, 2013-3 and 2013-4 Medium-Term Notes. Our earnings before interest and income tax for the twelve months ended December 31, 2013, for the purposes of calculating this ratio, were approximately $256.5 million (December 31, 2012 - $180.7 million; December 31, 2011 - $146.8 million).

Credit Ratings

	Year ended December 31,		
	2013	2012	2011
DBRS - Commercial paper[1]	**R-1 (low)**	R-1 (low)	R-1 (low)
DBRS - Senior secured bonds and medium-term notes (secured) [1]	**A**	A	A
Standard & Poor's - Senior secured bonds and medium-term notes [2]	**A-**	A-	A-

1. On September 25, 2013, DBRS confirmed the above ratings, both with stable trends.
2. On January 17, 2014, Standard & Poor's confirmed the above rating with a stable trend.

Commitments

		Payments due by periods			
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
(in millions of dollars)					
Short and long-term debt	**$ 2,700.0**	**$ —**	**$ —**	**$ 200.0**	**$ 2,500.0**
Operating leases	**45.0**	**4.8**	**9.3**	**9.5**	**21.4**
Total contractual obligations	**$ 2,745.0**	**$ 4.8**	**$ 9.3**	**$ 209.5**	**$ 2,521.4**

We have contractual commitments for the repayment of long-term debt in the amount of $2,700.0 million, as disclosed in note 11(d) – *Scheduled principal repayments*, in our Financial Statements.
We are committed to operating leases that have lease terms, which expire between 2014 and 2026. Of the total expected minimum lease payments, 87.3% relates to our head office leases. See note 21 – *Commitments*, in our Financial Statements.

We also have contractual commitments for the purchase of property, plant and equipment as at December 31, 2013 of $1,791.8 million. Of these commitments, approximately 86% are with ATP, a wholly-owned subsidiary of SNC.

Results of Operations

Revenue

	Year ended		
	December 31, 2013	December 31, 2012	December 31, 2011
(in millions of dollars)			
Operations	**$ 503.0**	$ 379.9	$ 343.2
Other	**31.1**	26.7	22.3

	Quarter ended		
	December 31, 2013	December 31, 2012	December 31, 2011
(in millions of dollars)			
Operations	**$ 170.9**	$ 110.8	$ 116.5
Other	**11.0**	9.0	6.0

Revenue from operations

Revenue from operations includes all revenue earned from providing electricity transmission services. The principal components of our transmission tariff include recovery of forecast operating costs, deemed income taxes, depreciation and amortization expenses, and return on rate base.

Compared to the same periods in 2012, our revenue from operations increased by $60.1 million and $123.1 million for the quarter and year ended December 31, 2013, respectively, primarily due to additional investments in capital assets.

Compared to the same period in 2011, our revenue from operations increased by $36.7 million for the year ended December 31, 2012, primarily due to additional investments in capital assets.

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

Other Revenue

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

Compared to the same periods in 2012, cost recovery revenue from third parties increased by $2.0 million and $4.4 million for the quarter and year ended December 31, 2013, respectively. Revenue associated with costs recovered from third parties is received on a cost recovery basis and there is no net income impact. The variances are primarily due to the volume of transmission construction services provided to third parties during these periods, which fluctuates in response to the need for such services and is not predictable. Compared to the same periods in 2011, cost recovery revenue from third parties increased by $3.0 million and $4.4 million for the quarter and years ended December 31, 2012, respectively for similar reasons to those noted above.

Comprehensive income

	December 31, 2013	December 31, 2012	December 31, 2011
(in millions of dollars)			
Year ended	**$ 164.4**	$ 107.0	$ 85.3
Quarter ended	**65.8**	31.3	30.3

Our comprehensive income for the quarter and year ended December 31, 2013 increased by $34.5 million and $57.4 million, respectively, compared to the same periods in 2012, primarily due to increased investment in electricity transmission infrastructure and the accrual for the collection of provincial future income taxes. Our net and comprehensive income for the quarter and year ended December 31, 2012 increased by $1.0 million and $21.7 million, respectively, compared to the same periods in 2011, primarily due to similar reasons, except for the accrual for the collection of provincial future income taxes.

Operating expenses

		December 31, 2013		December 31, 2012		December 31, 2011
(in millions of dollars)						
Year ended	**$**	**90.0**	$	78.9	$	73.8
Quarter ended		**25.5**		19.3		19.8

Our operating expenses include salaries and wages, contracted manpower and general and administration costs. Our operating expenses for the quarter and year ended December 31, 2013 increased by $6.2 million and $11.1 million, respectively, compared to the same periods in 2012, due to growth in our transmission system. Our operating expenses for the year ended December 31, 2012 increased by $5.1 million compared to the same period in 2011, due to both growth in our transmission system and an increase in cost recovery projects. Our operating expenses for the quarter ended December 31, 2012 decreased by $0.5 million, compared to the same period in 2011, due to adjustments recorded in the last quarter of 2011, following receipt of the 2011-12 GTA decision.

Property Taxes, Salvage, and Other

		December 31, 2013		December 31, 2012		December 31, 2011
(in millions of dollars)						
Year ended	**$**	**52.3**	$	45.1	$	44.6
Quarter ended		**15.9**		14.3		11.5

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

Our property taxes, salvage and other expenses increased by $1.6 million and $7.2 million, respectively, for the quarter and year ended December 31, 2013, compared to the same periods in 2012. The increase is due to the timing of salvage costs incurred and to increases in property tax expense and annual structure payments as a result of assets being put into service. Our property taxes, salvage and other expenses increased by $2.8 million and $0.5 million, for the quarter and year ended December 31, 2012, respectively, compared to the same periods in 2011. The increase is primarily due to the timing of salvage costs incurred.

Depreciation and amortization

		December 31, 2013		December 31, 2012		December 31, 2011
(in millions of dollars)						
Year ended	**$**	**133.1**	$	99.2	$	93.1
Quarter ended		**43.0**		31.3		31.3

We calculate depreciation and amortization on a straight-line basis using various rates which are approved by the AUC. Depreciation for the quarter and year ended December 31, 2013 increased by $11.7 million and $33.9 million, respectively, compared to the same periods in 2012, primarily as a result of an increase in capital projects that have been completed and added to our regulatory rate base.

Depreciation for the year ended December 31, 2012 increased by $6.1 million compared to the same period in 2011 primarily as a result of an increase in capital projects that have been completed and added to our regulatory rate base partially offset by recording a reduction in depreciation rates approved in Decision 2012-221. Depreciation for the three months ended December 31, 2012 had no change compared to the same period in 2011 due to a decrease in depreciation rates.

Finance costs

		December 31, 2013		December 31, 2012		December 31, 2011
(in millions of dollars)						
Year ended	**$**	**91.3**	$	73.0	$	62.4
Quarter ended		**28.5**		20.7		24.0

Finance costs include interest costs and amortization of deferred financing fees less capitalized borrowing costs. Our interest expense for the quarter and year ended December 31, 2013 increased by $7.8 million and $18.3 million, respectively, compared to the same periods in 2012, primarily due to interest costs associated with having a full year of interest on the $575.0 million of long-term debt that was issued subsequent to June 1, 2012 and as a result of the debt added throughout 2013. Our interest expense for the quarter and year ended December 31, 2012 decreased by $3.3 million and increased by $10.6 million, respectively, compared to the same periods in 2011. The lower quarterly finance costs in 2012 relate to the implementation of CWIP in rate base relief in the fourth quarter of 2011, following receipt of Decision 2011-453. In addition, the repayment of the subordinated debenture early in 2012 reduced total interest expense for the year and quarter ended December 31, 2012 relative to the 2011 periods. These reductions were partially offset by the impact of additional debt issued in 2011 and 2012.

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

	December 31, 2013	December 31, 2012	December 31, 2011
(in millions of dollars)			
Year ended	**$ 389.6**	$ 279.9	$ 241.5
Quarter ended	**137.4**	83.1	78.7

Our EBITDA for the quarter and year ended December 31, 2013 increased by $54.3 million and $109.7 million, respectively, compared to the same periods in 2012. The reasons for these increases are similar to those noted above for the changes in our comprehensive income for the same period. Please refer to "Non-GAAP Financial Measures" for more information about how we calculate EBITDA. Our EBITDA for the quarter and year ended December 31, 2012 increased by $4.4 million and $38.4 million respectively, compared to the same periods in 2011. The reasons for these increases are similar to those noted above for the changes in our net income for the same periods.

Selected Financial Information Derived from our Financial Statements

	December 31, 2013	December 31, 2012	December 31, 2011
Net income per unit ($/unit)	**0.487**	0.326	0.258
Funds generated from operations ($ millions)	**253.9**	196.0	156.5
Distributions per unit ($/unit)	**0.115**	0.110	0.093
Total assets ($ millions)	**5,858.2**	4,083.7	3,156.5
Short and long term debt ($ millions) [1]	**2,743.9**	1,803.5	1,331.1

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

Summary of Quarterly Financial Information

Quarter ended	Revenue ($ millions)	Net income ($ millions)	Units outstanding (millions)	Net income per unit ($/unit)
December 31, 2013	**181.9**	**62.7**	**331.9**	**0.189**
September 30, 2013	125.5	38.4	331.9	0.116
June 30, 2013	117.5	33.4	331.9	0.100
March 31, 2013	109.2	27.2	331.9	0.082
December 31, 2012	119.8	32.2	331.9	0.097
September 30, 2012	97.6	27.3	331.9	0.082
June 30, 2012	96.7	25.9	331.9	0.078
March 31, 2012	92.5	22.9	331.9	0.069
December 31, 2011	122.5	30.7	331.9	0.092
September 30, 2011	82.1	20.6	331.9	0.062
June 30, 2011	84.7	17.1	331.9	0.052
March 31, 2011	76.3	17.4	331.9	0.052

Risk Management

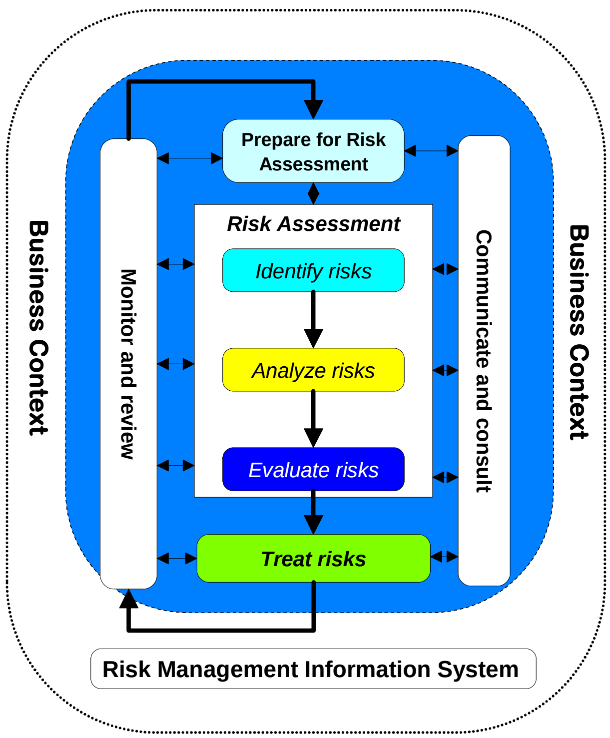
Our transmission business is subject to risks and uncertainties, including those described below. Our goal is to manage these risks to reasonably protect us from unacceptable outcomes including undesirable financial results. You should carefully consider these risk factors and uncertainties in addition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

Our Approach to Enterprise Risk Management

We use an enterprise-wide portfolio approach to manage key business risks. These risks stem from the uncertainty that permeates our business. Managing these risks successfully requires a systematic, structured and timely approach. To achieve this, we have developed an enterprise risk management ("ERM") policy which has been approved by our Board of Directors. We have also defined an ERM Framework and developed an ERM program modelled after the ISO 31000 standard. A primary goal of our ERM program is to provide uniform processes to identify, analyze, evaluate, treat and report our key risks for the benefit of our customers and shareholders. By strengthening our risk management practices, ERM supports the corporate governance needs of our Board of Directors and the due diligence responsibilities of senior management.

We integrate risk management with our strategic planning and business planning processes to promote and facilitate proactive management of risks and opportunities that may impact our strategic and business objectives.

The following diagram depicts our ERM process.



Risk Assessments

Risk assessments involve identifying, analyzing and evaluating the risks we face. Some of the methods we use to identify risks and opportunities include management interviews, facilitated risk workshops, and stakeholder discussions. Under our ERM program, we conduct annual risk assessments to identify and analyze our most significant risks and opportunities and the existing controls which manage them. Risk owners are defined for all of our key risks. We then combine quantitative and qualitative methods to analyze the residual likelihood and potential impact associated with the risks and opportunities.

We use a heat map as a tool to document residual risk levels for our most significant risks and opportunities. These heat maps and our risk criteria are also helpful in determining whether risk treatment plans should be prepared. We consider previously set risk targets and risk velocity when deciding whether risk treatment plans are appropriate. The greater the speed or velocity at which we expect the risks, events or opportunities could materialize; the greater the likelihood that a risk treatment plan is necessary or appropriate.

Our risk management program facilitates management's quarterly review and update of current and emerging risks or opportunities against our approved risk criteria.

Risk treatment involves making decisions as to the appropriate course of action to increase or decrease risk to target or optimal levels. Risk treatment approaches may include avoiding the risk by discontinuing activities, taking an appropriate amount of additional risk to pursue opportunities, taking actions to modify the likelihood or consequence of the risk, sharing or outsourcing the risk, or making an informed choice to retain the risk at the already appropriate level. Management monitors residual risks and risk treatment plan implementation and reports the status to the Board of Directors quarterly.

Insurance and Statutory Liability Protection

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

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

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

Risk Factors and Uncertainties

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

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

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

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

Project Execution

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

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

These project risks can translate into performance issues and project delays, which under traditional regulatory accounting would delay the receipt of expected cash flows related to a project. Delays in receiving cash flows for large projects could have a material adverse impact on our credit metrics, which are considered by debt rating agencies in assigning a particular rating to our debt securities. This risk was mitigated for 2011 through to 2014 in part because the AUC has approved the use of the CWIP in rate base method in determining our 2011-14 transmission tariffs.

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

Regulatory Financial Risk

As the AESO directly assigns the construction of large multi-year transmission facility projects to us, 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.

Recent AUC decisions have been supportive of these increased debt service requirements by providing credit metric support through both CWIP in Rate Base and the recovery of Provincial and Federal future income taxes in our revenue requirement. However, 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.

Similarly, our rating agencies DBRS and Standard & Poors (S&P), have identified ongoing regulatory support during our significant capital expenditure program in the next few years as a risk to maintaining our credit profile. In addition, both rating agencies have also identified the reliance on our parent company for equity injections as credit risks. In its September 25, 2013 report, DBRS stated that it believes our parent company has the financial capability and commitment to fund the equity portion of our projects. S&P, in their report dated January 17, 2014 stated that AltaLink's dependence on equity support from SNC is diminishing because the large capital program is winding down.

In Decision 2013-407, related to our 2013-14 GTA, the AUC expressed concern that the rates negotiated by us in the new contracts with external providers for engineering, procurement and construction management services may not be competitive. The AUC ruled that it could not accept the rates resulting from the competitive procurement process. As a result, it did not allow the rates proposed by us for forecasting capital expenditures. The AUC said that it expects our capital project expenditures to be subject to a future DACDA application, at which time we intend to provide evidence to support our position that the rates for the EPCM services are competitive.

In addition, the AUC expressed concern regarding certain actions taken by us with respect to cost, consultation and schedule for the South West project. Consequently, the Commission has ordered an audit for the South West project and has approved placeholder treatment for project costs pending final assessment of the prudence of the project costs. We intend to provide evidence to support our position that the costs associated with the South West project were prudently incurred.

As noted above, we cannot predict with certainty how AUC decisions may adversely impact us and there can be no assurance that we can entirely recover the actual costs of directly assigned capital projects through the revenue requirement approved by the AUC. Substantial unrecovered costs could have a material adverse effect on our financial condition and results of our operations.

Reliability

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

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

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

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

Restructuring of Electricity Industry

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

Capital Resources

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

Labour Relations

Approximately 60% of our employees are members of one of two labour unions, the United Utility Workers Association (UUWA), who have about 450 AltaLink members, or the International Brotherhood of Electrical Workers (IBEW), who have about 25 AltaLink members. These two unions have entered into collective bargaining agreements with our general partner. The provisions of these collective agreements affect the flexibility and efficiency of our business. We have negotiated a renewed collective bargaining agreement with the UUWA, which is effective from January 1, 2013 to December 31, 2015. We have negotiated a renewed collective bargaining agreement with the IBEW, which is effective from January 1, 2014 to December 31, 2016. We consider our relationships with these labour unions to be satisfactory; however, there can be no assurance that current relations will not change in negotiations or mediation, or that the collective bargaining agreements will not be renewed on acceptable terms. If these events occur, we could face the risks of service interruptions arising from labour disputes or increased labour costs. The inability to recover any significant difference between forecast and actual labour costs could adversely affect our financial condition and results of our operations.

Availability of People

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

Environment, Health and Safety

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

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

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

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

Electric and Magnetic Fields

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

Annual Impairment Tests

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

Competition

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

Credit Ratings

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

Cyber Security

We have recognized the growing importance of actively managing risk related to cyber security. In 2013, we assessed various risks associated with the integrated network operations and information systems and the maturity of our information technology (IT) governance procedures. We also completed a number of reviews in 2013 to assess the effectiveness of our IT governance, cyber security and general IT controls. During these reviews we compared our procedures with leading practices in the Canadian and US utility industries.

We utilized a third party, a subject matter expert in IT security, with extensive experience in assessing utilities in Canada. Their independent opinion of our network security versus peers in Canada ranged between average to a leading practice in specific areas.

As a result of these assessments, we have created a three year plan to enhance our IT risk management procedures and controls and bring them into line with leading practices in our industry. Our plan also includes steps to ensure that we continue to meet all regulatory compliance requirements with respect to information technology and cyber security controls and procedures.

Transactions with Related Parties

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

We have incurred construction related services costs of $373.4 million and $1,529.9 million with ATP during the quarter and year ended December 31, 2013, compared to $275.1 million and $784.7 million, respectively, for the same periods in 2012, and $206.0 million and $419.6 million for the same periods in 2011. On December 31, 2013, our accounts payable and accrued liabilities included $287.9 million owing to ATP, compared to $167.4 million at December 31, 2012, and $143.9 million at December 31, 2011.

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

Legal Proceedings

We have not commenced and are not currently contemplating any legal proceedings that would have a material impact on our financial results. We are not aware of any material legal proceedings that have been commenced or are being contemplated against us.

Off Balance Sheet Arrangements

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

Critical Accounting Estimates

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

Contingencies

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

Accounting Changes

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

Standards effective beginning on or after January 1, 2013

We adopted the following standards:

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

Adoption of the above standards had no material impact on our financial statements or our disclosures.

Amendments to standards effective beginning on or after January 1, 2013

We implemented the following amendments:

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

Implementation of the above amendments had no material impact on our financial statements or our disclosures.

Future Accounting Changes That May Impact Our Financial Statements

Effective after 2013

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

- IFRS 9 - *Financial instruments: Classification and measurement*. We are evaluating the potential impact on our financial statements. Currently, we do not expect that adopting this standard will have a material impact on our financial statements.
- Amendments to IAS 32 - *Financial instruments: Presentation*. We do not expect that adopting these amendments will have a material impact on our financial statements.
- IFRIC 21 – *Levies* was issued in May 2013 and is an interpretation of IAS 37 – *Provisions, Contingent Liabilities and Contingent Assets.* The interpretation clarifies the obligating event that gives rise to a liability to pay a levy. IFRIC 21 is effective for periods beginning on or after January 1, 2014. We are currently evaluating the impact of this interpretation on our financial statements.

Update on the International Accounting Standards Board (IASB) work plan and rate-regulated project

The IASB's comprehensive rate-regulated activities project has two distinct components at this time. Firstly, there is a component to develop an interim standard for the recognition of regulatory balances within IFRS reporting until the remainder of the comprehensive project is completed. Secondly, there is a research project, which aims to develop a Discussion Paper to consider whether rate regulation creates assets or liabilities that should be recognized in accordance with IFRS.

The IASB issued an Exposure Draft regarding Regulatory Deferral Accounts in April, 2013, which proposed to provide temporary guidance on accounting for rate-regulated activities for first-time adopters of IFRS. The objective of the proposed interim standard was to enhance the comparability of financial reporting by entities with rate-regulated activities until guidance is developed through research on accounting for assets and liabilities arising from rate regulated activities. The IASB's process for considering this component of the project has been completed, and the IASB issued the interim standard on January 30, 2014.

In March, 2013, the IASB issued a Request for Information to gather high-level overviews of the types of rate-regulation that are currently in force to help determine the scope of the IASB's research project for rate-regulated activities. The IASB received a significant number of responses to this request. The Request for Information asked specific questions about the objectives of rate-regulation and how those objectives are reflected in the rate-setting mechanisms employed by rate regulators. The information identified through this Request for Information and other research is being used to develop a Discussion Paper. The aim of the Discussion Paper is to identify what information about the consequences of rate-regulation would be most useful for users of IFRS financial statements and whether the IASB should develop specific guidance for accounting for those consequences.

The IASB established a consultative group for this research project. The group held a meeting in July and a follow up meeting in November to provide input into the issues that were identified. During 2014, the group will continue to be involved in the second component of this project, i.e. the development of the Discussion Paper. We expect that the Discussion Paper will be issued in the middle of 2014.

Forward Looking Information

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

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

- no changes in the legislative and operating framework for Alberta's electricity market that are adverse to us;
- decisions from the AUC concerning outstanding tariff and other applications that are consistent with past regulatory practices and decisions and are obtained in a timely manner;
- approved rates-of-return and deemed capital structures for our transmission business that are sufficient to foster a stable investment climate;
- a stable competitive environment;
- obtaining sufficient capital on acceptable terms to finance our transmission system expansion; and,
- no significant event occurring outside the ordinary course of business such as a natural disaster or other calamity.

These assumptions and factors are based on information currently available to us including information obtained by us from third-party industry analysts. In some occurrences, material assumptions and factors are presented or discussed elsewhere in this document in connection with the statements or disclosure containing the forward-looking information. We caution prospective investors that the foregoing list of material factors and assumptions is not exhaustive.

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

- the risks associated with being subject to extensive regulation including risks associated with AUC action or inaction;
- the risk that the AUC does not provide specific relief to support us in sustaining our credit metrics over a growth period characterized by large, multi-year transmission facilities projects;
- the risk that transmission projects are not directly assigned to us by the AESO or that we are not designated for filing a facility application;
- the risk that we are not able to arrange sufficient, cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risk that system expansion plans are delayed;
- the risks that the actual costs of completing a transmission project significantly exceed estimated costs;
- the risks to our facilities posed by severe weather, other natural disasters or catastrophic events and the limitations on our 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 and administrative costs above those included in our approved revenue requirement.

We caution prospective investors that the above list of risk factors is not exhaustive. Other factors, which could cause our actual results, performance or achievements to differ materially from those contemplated (whether expressly or by implication) in the forward-looking statements or other forward-looking information, are disclosed in our publicly filed disclosure documents, including those disclosed under "Risk Factors and Uncertainties" in this MD&A and under "Risk Factors" in our Annual Information Form. Risk factors that could lead to such differences include, without limitation, legislative and regulatory developments that could affect costs or revenues, the speed and degree of competition entering the market, global capital markets conditions and activity, timing and extent of changes in prevailing interest rates, currency exchange rates, inflation levels and general economic conditions in geographic areas where we operate, results of financing efforts, changes in counterparty risks, and the impact of accounting standards issued by standard setters.

All forward-looking information is given as of February 27, 2014. 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.