

re:GENERATING

Q3/2009



ALGONQUIN
 POWER

Report to Unitholders

In the third quarter of 2009, Algonquin Power Income Fund showed results consistent with those in earlier quarters of 2009, demonstrating the strength our operations have in withstanding fluctuations in today's economic climate. While lower average energy rates, natural gas prices and a decrease in production have resulted in revenue and EBITDA coming in below our expectations, Algonquin's well diversified asset base and long-term contracts minimize fluctuations in performance and help to stabilize cash-flow. As a result, we have been able to continue throughout the quarter to focus our attention on a number of activities that will strengthen our position as a strong, successful power and utilities company.

A major accomplishment in the third quarter was the announcement of our intention to change the company from an income trust structure to a dividend paying corporation named Algonquin Power & Utilities Corp. This change, successfully completed at the end of October, represents an important milestone in the evolution into a growth oriented, dividend paying power and utility company. The shares of the corporation began trading on the Toronto Stock Exchange on October 29, 2009 under the symbol AQN and will continue to receive the same dividend as was paid on units of the Fund, which is presently \$0.24 per unit per year. The new structure will contribute to Algonquin's continuous focus on providing total shareholder return through a combination of dividends and capital appreciation realized through the successful execution of our growth strategies. The Board believes that the new corporate structure will better position Algonquin Power within the capital markets and will increase our competitive effectiveness in the power and utility sectors.

Following on the successful transition to a corporate structure, on November 10, 2009, Algonquin was very pleased to announce that it had entered an agreement to acquire three hydroelectric generating facilities totalling 36.8MW, located in New Brunswick and Maine. The hydro plants are interconnected to access the northeastern electricity markets of Northern Maine, New Brunswick, and New England, and are under firm energy and capacity sale contracts continuing through February 2011, with several future contract opportunities available beyond the existing contract expiries. The earnings and cash flow accretion generated by these long lived, utility grade hydroelectric generating facilities supports Algonquin's total shareholder return commitment by delivering growth of more than 10% in our renewable energy business.

Also on November 10, 2009, Algonquin announced a \$75 million offering of common shares and convertible debentures through an agreement to sell to a syndicate of underwriters led by CIBC World Markets Inc. and BMO Capital Markets, on a bought deal basis, 5,980,000 common shares at \$3.35 per common share for gross proceeds of \$20 million and \$55 million principal amount of 7% convertible unsecured subordinated debentures due June 30, 2017.

Proceeds of approximately \$35 million from the debenture offering will be used to reduce existing senior short term bank credit facilities. The proceeds of the common share offering and the balance of the debenture offering will be used to finance the hydroelectric generating facility acquisition noted above.

In the Power & Development division, Algonquin continues to advance several development projects including the Red Lily Wind Project and the re-contracting of the Windsor Locks facility. A Power Purchase Agreement with SaskPower is in place for the 25 MW first phase of the Red Lily project, and Algonquin has executed an agreement under the ecoENERGY for Renewable Power Program securing some of the funding for the project. During the quarter, Algonquin secured additional property in the area and is assessing the viability of an expanded project, which would be conditional upon operating results from the first phase. With respect to the re-contracting of Windsor Locks, the current Power Purchase Agreement with Connecticut Light & Power expires in 2010 and a number of options are being considered including maximizing net revenue from the existing equipment, and a

repowering of the facility. We will continue to provide you with updates on the progress of these two important projects over the coming quarters.

In the Utility Services division, we continue to progress with a number of requests for rate increases that have been initiated throughout 2009. Although we are experiencing some delays in the regulatory process, we anticipate that 2010 will see a revenue increase of \$7 million from the division.

Algonquin is committed to growth in cash flow, earnings and dividends through an expanding pipeline of renewable power and clean energy projects, organically within its regulated utilities services areas as well as through the pursuit of accretive acquisition opportunities. So far 2009 has been a very active year for Algonquin Power, with the announcement of the acquisition of an electrical distribution utility in April and the change from an income trust structure to a corporation. Through these activities, we aim to focus on value creation while operating within a moderate risk profile and enhancing long-term shareholder value. You are encouraged to obtain further detail about the performance of Algonquin in the Management's Discussion & Analysis. Thank you for your continued investment in Algonquin Power.

(signed) Ken Moore

Ken Moore

*Chairman of the Board of Directors
Algonquin Power & Utilities Corp.*

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per trust unit and convertible debenture values or where otherwise noted)

Algonquin Power Income Fund ("Algonquin") has prepared the following discussion and analysis to provide information to assist its unitholders' understanding of the financial results for the three and nine months ended September 30, 2009. This discussion and analysis should be read in conjunction with Algonquin's unaudited consolidated interim financial statements for the three and nine months ended September 30, 2009 and 2008 and the notes thereto. This material is available on SEDAR at www.sedar.com and on the Algonquin website at www.AlgonquinPower.com. Additional information about Algonquin, including the Annual Information Form for the year ended December 31, 2008 can be found on SEDAR at www.sedar.com.

This Management's Discussion and Analysis ("MD&A") is based on information available to management as of November 4, 2009.

Caution concerning forward looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of Algonquin and Algonquin Power Management Inc. ("APMI"), the entity which provides management services to Algonquin (including advice and consultation concerning business planning, support, guidance and policy making) with respect to future events, based upon assumptions relating to, among others, the performance of Algonquin's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of Algonquin, its future plans and its distributions to unitholders. Statements containing expressions such as "outlook", "believes", "anticipates", "continues", "could", "expect", "may", "will", "project", "estimates", "intend", "plan" and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require us to make assumptions and involve inherent risks and uncertainties. Algonquin and APMI caution that although we believe our assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that our actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the continued volatility of world financial markets; the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy and the taxation of income funds; and the state of the Canadian and the United States ("U.S.") economy and accompanying business climate. Algonquin and APMI caution that this list is not exhaustive, and other factors could adversely affect our results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Algonquin reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin and APMI believe that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of the dates hereof. Algonquin and APMI are not obligated nor do either of them intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures", "adjusted net earnings" and "earnings before interest, taxes, depreciation and amortization" ("EBITDA") are used throughout this MD&A. The terms "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures", "adjusted net earnings" and EBITDA are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). There is no standardized measure of "cash available for distribution", "cash available for distribution after growth and maintenance capital

expenditures”, “adjusted net earnings” and EBITDA, consequently Algonquin’s method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of “cash available for distribution”, “cash available for distribution after growth and maintenance capital expenditures”, “adjusted net earnings” and EBITDA can be found throughout this MD&A.

Overview

Algonquin is a mutual fund trust that owns and has interests in a diverse portfolio of clean, renewable power generation and sustainable infrastructure assets across North America, including 42 renewable energy facilities, 13 thermal energy facilities, and 18 water distribution and wastewater facilities. Algonquin was established in 1997 and produces stable earnings through a diversified portfolio of renewable energy and utility assets.

Algonquin owns 41 hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New York State, New Hampshire, Vermont and New Jersey with a combined generating capacity of 140 MW. Algonquin also owns a 99 MW wind farm in Manitoba. The renewable energy facilities are generally facilities operating under long term power purchase agreements with major utilities and have an average remaining contract life of 18 years. Algonquin’s 13 thermal energy facilities operate under power purchase agreements (“PPAs”) and have an average remaining contract life of 10 years with a combined generating capacity of 356 MW. In addition to its electricity generating assets, Algonquin also owns in its Utility Services business unit 18 regulated water distribution and wastewater facilities in Arizona, Illinois, Missouri and Texas. These utility operating companies are regulated investor-owned utilities subject to regulation, including rate regulation, by the public utility commissions of the states in which they operate.

Business Strategy and recent developments

Algonquin’s business strategy is to maximize long term unitholder value by strengthening its position as a strong renewable energy and infrastructure company through growth from greenfield renewable power and clean energy projects, from organic growth from existing facilities, and from accretive acquisitions within the business segments in which it operates. Algonquin is focused on growing cash flow, earnings and distributions. Algonquin currently makes monthly cash distributions to unitholders of \$0.02 per trust unit per month or \$0.24 per trust unit per annum. This level of cash distributions allows for both an immediate return on investment for unitholders and retention of sufficient cash within Algonquin to fund growth opportunities, debt repayment and mitigate the impact of volatility in foreign exchange rates. Algonquin strives to achieve its results within a moderate risk profile consistent with top-quartile North American power, utility, and infrastructure operations.

Algonquin’s operations are aligned into two major business units: Power Generation & Development, and Utility Services.

The Power Generation & Development business unit develops and operates a diversified portfolio of electrical energy generation facilities. Within this business unit there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates Algonquin’s hydroelectric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops Algonquin’s greenfield power generation projects, pursues accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within Algonquin’s existing portfolio of renewable energy and thermal energy facilities. The renewable power and thermal energy generation business of Algonquin is managed with an emphasis on growth through the development of green-field projects and opportunities within Algonquin’s existing portfolio. This involves building on Algonquin’s expertise in the origination of greenfield renewable energy projects, building

upon Algonquin's existing portfolio of assets for further growth, and capitalizing on opportunities that may emerge in the current turbulence of the capital markets.

The Utility Services business unit targets delivery of long term shareholder value by profitably operating and strategically managing a portfolio of utility and utility-like infrastructure businesses and delivering continued growth in earnings by discerningly identifying opportunities which accretively expand its business portfolio. The current focus of the Utility Services business unit is on the provision of safe, reliable transportation and delivery of water and wastewater treatment in its service area. To leverage its experience in the regulated water utility sector, Utility Services is committed to expanding its operations into other regulated essential utilities such as electricity and natural gas distribution.

Acquisition announcement

On April 23, 2009, Algonquin announced that it plans to co-acquire an electrical generation and regulated distribution utility through a strategic partnership with Emera Inc. ("Emera"). Algonquin and Emera will each own 50% of the newly formed California Pacific Electric Company, LLC, a California limited liability company ("Calpeco"), which intends to acquire the California-based electricity distribution and related generation assets (the "California Utility") of NV Energy, Inc. for the purchase price of approximately US \$116 million, subject to certain working capital and other closing adjustments. Algonquin and Emera will jointly own and operate the California Utility through Calpeco. The California Utility currently provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The transaction is subject to state and federal regulatory approval which is expected to occur in 2010.

As an element of the California Utility strategic partnership, Emera has also agreed to a conditional treasury subscription of approximately 8.5 million trust units of Algonquin at a price of \$3.25 per unit. Delivery of the trust units under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of the California Utility.

As of September 30, 2009, Algonquin has incurred costs of \$0.8 million related to the acquisition of the California Utility. These costs are recorded as deferred transaction costs in other assets on the Consolidated Balance Sheet. In October 2009, an application was filed with the California Public Utilities Commission requesting approval of the transaction in which NV Energy has agreed to sell its California electric distribution and generation assets to Calpeco.

Unit Exchange announcement

During the second quarter of 2009, the Board of Trustees of Algonquin (the "Board") announced that they had entered into a unit-share exchange support agreement to support an offer (the "Unit Exchange Offer") which would provide Algonquin's unitholders the opportunity to exchange their trust units of Algonquin, on a one-for-one basis, for common shares of Hydrogenics Corporation an existing corporation which pursuant to a Plan of Arrangement would have all operations and existing shares transferred to a new Hydrogenics Corporation ("New Hydrogenics") immediately before the Unit Exchange Offer occurs. The remaining Hydrogenics Corporation would be renamed by Algonquin following closing of the transactions contemplated by the Unit Exchange Offer.

Subsequent to September 30, 2009, on October 27, 2009 Algonquin unitholders exchanged 100% of outstanding trust units for a new class of common shares ("New Common Shares") of Algonquin Power & Utilities Corp. ("APUC"), (formerly Hydrogenics Corporation), on a one for one basis. As a result, the existing unitholders of Algonquin became shareholders of APUC and Algonquin became a subsidiary entity of APUC. Excluding shares issued under the CD Exchange Offer (as defined below), the number of common shares of APUC outstanding

immediately after completion of the transactions described herein would be exactly the same as the number of Algonquin trust units outstanding immediately before the Unit Exchange Offer.

As required under the Support Agreement, immediately following closing of the Unit Exchange Offer, APUC paid New Hydrogenics approximately \$10,813. APUC retains tax attributes of approximately \$192,000 which is in addition to the existing tax attributes of the Algonquin.

CD Exchange announcement

During the second quarter of 2009, the Board also announced that, in conjunction with the Unit Exchange Offer, holders of Algonquin's convertible debentures would be provided the opportunity to exchange their debentures for new debentures of APUC (the "CD Exchange Offer") on the following terms:

In respect of the 6.65% convertible debentures maturing on July 31, 2011 ("Series 1"), holders of Series 1 debentures would receive, for each \$1 of Series 1 debenture principal, either of the following, at the option of each debenture holder to be exercised at the time of tender of their debentures:

(a) 311.52 common shares in APUC

- i. A maximum of 12,460,800 common shares will be available under this option and, if demand for this option exceeds such amount, such shares will be allocated pro-rata amongst tendering debenture holders; or

(b) a convertible debenture issued by APUC ("New Series 1") with the following terms:

- i. Principal: \$1.05
- ii. Coupon: 7.50%, payable semi-annually (Series 1 coupon is 6.65%)
- iii. Conversion Price: \$4.08 for each APUC share, representing a conversion premium of 20% over the most recent closing price of Algonquin's trust units of \$3.40. (Series 1 conversion price is \$10.65 for each Algonquin trust unit)
- iv. Maturity: November 30, 2014

In respect of the 6.20% convertible debentures maturing on November 30, 2016 ("Series 2"), holders of the Series 2 debentures would receive, for each \$1 of Series 2 debenture principal, a convertible debenture issued by APUC ("New Series 2") with the following terms:

- i. Principal: \$1.00
- ii. Coupon: 6.35%, payable semi-annually (Series 2 coupon is 6.20%)
- iii. Conversion Price: \$6.00 for each APUC share (Series 2 conversion price is \$11.00 for each Algonquin trust unit)
- iv. Maturity: November 30, 2016

Subsequent to September 30, 2009, on October 27, 2009 holders of Algonquin's convertible debentures exchanged their convertible debentures for convertible debentures of APUC (the "New Debentures") or New Common Shares resulting in, among other things, Algonquin's debentureholders becoming debentureholders of APUC.

Pursuant to the CD Exchange Offer, \$63,755 of the outstanding Series 1 debentures were exchanged for New Series 1 convertible unsecured subordinated debentures in a principal amount of \$66,943 and \$21,209 of the Series 1 debentures were exchanged for 6,607,027 shares of APUC. In addition, all of the outstanding Series 2 debentures were exchanged for New Series 2 convertible unsecured subordinated debentures in a principal amount of \$59,967.

A description of the accounting treatment related to the Unit Exchange and CD Exchange Offer can be found later in this document under Accounting Treatment for the Unit Exchange and CD Exchange Offer.

Corporate Governance

At the annual general meeting of unitholders held on July 27, 2009, in addition to the re-election of existing Trustees, Mr. Huskison was elected as a Trustee. The Board and management of Algonquin believe that Mr. Huskison's utility and power experience will make a strong addition to the Board and will support Algonquin's long term strategy and corporate governance activities.

Management Internalization

As previously announced the Board has commenced a process to internalize management at Algonquin. The Board has retained advisors to assist them in the process and continues to discuss the internalization of management with APMI. The Board expects to complete the internalization of management by the end of 2009. On an interim basis, the management of APUC is being undertaken by APMI pursuant to the existing management agreement.

2009 Nine month results from operations

Key Selected Nine Month Financial Information

	Nine months ended September 30	
	2009	2008
Revenue	\$ 143,824	\$ 157,291
EBITDA ²	\$ 61,341	\$ 66,772
Cash provided by Operating Activities	37,473	52,471
Net earnings	32,623	2,057
Adjusted net earnings ²	18,999	9,949
Distribution to Unitholders ¹	14,328	52,981
Per trust unit:		
Net earnings	\$ 0.42	\$ 0.03
Adjusted net earnings ²	\$ 0.24	\$ 0.13
Diluted net earnings	\$ 0.42	\$ 0.01
Cash provided by Operating Activities	\$ 0.47	\$ 0.68
Distribution to Unitholders	\$ 0.18	\$ 0.69
Total Assets	925,702	962,722
Long Term Debt	278,025	296,791

¹ Includes distributions to Algonquin unitholders and Airsource units exchangeable into Algonquin units.

² Non-GAAP measurement, see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 3.

For the nine months ended September 30, 2009, Algonquin reported total revenue of \$143.8 million as compared to \$157.3 million during the same period in 2008, a \$13.5 million or 8.6% decrease. The decrease in revenue from energy sales in the nine months ended September 30, 2009 was primarily the result of \$18.1 million in lower

revenue due to reduced average energy rates and production at the Sanger and Windsor Locks facilities in the Thermal Energy division, and \$4.9 million lower revenue due to lower weighted average energy rates and energy production generated in the Renewable Energy division, as compared to the same period in 2008. These decreases were partially offset by an increase of \$2.6 million due to the Brampton Cogeneration Inc. ("BCI") facility being operational in the Thermal Energy division as compared to the same period in 2008 where BCI commenced operations June 2008. Algonquin reported increased revenue of \$5.9 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008. A more detailed analysis of these factors is presented within the business unit analysis. Algonquin attributes the reduced average energy rates to the overall effect the economic slow down has had on energy prices primarily in New York and New England where its hydro electric plants sell merchant power. Algonquin attributes lower revenue at its Sanger and Windsor Locks facilities to lower gas prices and to lower demand from the steam hosts resulting from the recession in the U.S.

For the nine months ended September 30, 2009, Algonquin experienced an average U.S. exchange rate of approximately \$1.170 as compared to \$1.019 in the same period in 2008. As such, any year over year variance in revenue or expenses, in local currency, at any of Algonquin's U.S. entities are affected by a change in the average exchange rate, upon conversion to Algonquin's reporting currency. Although a weaker Canadian dollar relative to the U.S. dollar has an impact on both revenue and expenses generated by its U.S. subsidiaries, Algonquin's foreign exchange forward contracts partially offset the impact on earnings (see Risk Management).

EBITDA in the nine months ended September 30, 2009 totalled \$61.3 million as compared to \$66.8 million during the same period in 2008, a decrease of \$5.4 million or 8.1%. The decrease in EBITDA is primarily related to lower earnings from operations resulting from lower gas prices and reduced demand for steam in the Thermal Energy division and lower average energy rates earned by the Renewable Energy division's U.S. facilities. A more detailed analysis of these factors is presented within the reconciliation of EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the nine months ended September 30, 2009, net earnings totalled \$32.6 million as compared to net earnings of \$2.1 million during the same period in 2008. Net earnings per trust unit totalled \$0.42 for the nine months ended September 30, 2009, as compared to net earnings per trust unit of \$0.03 during the same period in 2008.

The increase in net earnings as compared to 2008 was primarily the result of income of \$32.0 million due to unrealized mark to market gains on derivative financial instruments partially offset by losses on derivative financial instruments contracts settled in the period, as a result of increased interest rates and the weaker Canadian dollar.

Unrealized mark to market losses on derivative financial instruments resulting from changes in foreign exchange rates relate to contract periods which extend to fiscal 2013. Unrealized mark to market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. The following chart provides a summary of the period over period changes between realized and unrealized mark to market gains and losses of derivative financial instruments:

	Nine months ended September 30		
	2009	2008	Change
Foreign Exchange Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	\$ (14,421)	\$ 7,890	\$ (22,311)
Realized loss/(gain) on derivative financial instruments	431	(5,422)	\$ 5,853
	\$ (13,990)	\$ 2,468	\$ (16,458)

	Nine months ended September 30		
	2009	2008	Change
Interest Rate Swap Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	\$ (5,797)	\$ 3,894	\$ (9,691)
Realized loss/(gain) on derivative financial instruments	<u>3,984</u>	<u>260</u>	<u>\$ 3,724</u>
	\$ (1,813)	\$ 4,154	\$ (5,967)
Derivative Financial Instruments Total:			
Unrealized mark to market loss/(gain) on derivative financial instruments	\$ (20,218)	\$ 11,784	\$ (32,002)
Realized loss/(gain) on derivative financial instruments	<u>4,415</u>	<u>(5,162)</u>	<u>\$ 9,577</u>
Total loss/(gain) on derivative financial instruments	\$ (15,803)	\$ 6,622	\$ (22,425)

In addition, net earnings for the nine months ended September 30, 2009 increased \$12.2 million related to a recovery in future income taxes primarily due to the final determinations made for claiming discretionary deductions on 2008 income tax returns, the impact of which reduces future income tax liabilities previously recorded, as well as tax losses on U.S. operations resulting from bonus depreciation and lower natural gas prices. Net earnings were also impacted by \$4.8 million from reduced interest expense due to lower rates on Algonquin's variable interest rate debt booked in the period, \$2.7 million due to non-cash gains resulting from the weaker Canadian dollar and \$0.5 million due to increased earnings on portfolio investments as compared to the same period in 2008. These items were partially offset by \$2.2 million due to increased amortization expense, \$4.3 million due to lower earnings from operating facilities, \$1.6 million due to increased administrative expenses and \$3.7 million resulting from increased minority interest gains at the St. Leon facility primarily due to unrealized gains on financial instruments.

During the nine months ended September 30, 2009, cash provided by operating activities totalled \$37.5 million or \$0.47 per trust unit as compared to cash provided by operating activities of \$52.5 million, or \$0.68 per trust unit during the same period in 2008. The change in cash provided by operating activities after changes in working capital in the nine months ended September 30, 2009 is primarily due to increased realized losses from derivative instruments and decreased earnings from operating facilities, as compared to the same period in 2008.

2009 Third quarter results from operations

Key Selected Quarterly Financial Information

	Three months ended September 30	
	2009	2008
Revenue	\$ 45,110	\$ 55,084
EBITDA 2	\$ 20,276	\$ 22,236
Cash provided by Operating Activities	14,388	21,062
Net earnings	13,078	(4,406)
Adjusted net earnings 2	7,243	1,722
Distribution to Unitholders 1	4,775	18,019

	Three months ended September 30	
	2009	2008
Per trust unit		
Net earnings	\$ 0.17	\$ (0.06)
Adjusted net earnings ²	\$ 0.09	\$ 0.02
Diluted net earnings	\$ 0.17	\$ (0.06)
Cash provided by Operating Activities	\$ 0.18	\$ 0.27
Distribution to Unitholders	\$ 0.06	\$ 0.23
Total Assets	925,702	962,722
Long Term Debt	278,025	296,791

1 Includes distributions to Algonquin unitholders and Airsource units exchangeable into Algonquin units.

2 Non-GAAP measurement, see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 3.

For the three months ended September 30, 2009, Algonquin reported total revenue of \$45.1 million as compared to \$55.1 million during the same period in 2008, a decrease of \$10.0 million or 18.1%. The decrease in revenue from energy sales in the three months ended September 30, 2009 was primarily the result of \$8.8 million due to reduced average energy rates and production at the Sanger and Windsor Locks facilities in the Thermal Energy division, \$1.6 million due to lower weighted average energy rates and hydrology in the Renewable Energy division, as compared to the same period in 2008. These decreases were partially offset by a revenue increase of \$1.5 million in the Utility Services business unit as compared to the same period in 2008. In addition, Algonquin reported increased revenue of \$1.2 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008. A more detailed analysis of these factors is presented within the business unit analysis.

For the three months ended September 30, 2009, Algonquin experienced an average U.S. exchange rate of approximately \$1.097 as compared to \$1.042 in the same period in 2008. As such, any year over year variance in revenue or expenses, in local currency, at any of Algonquin's U.S. entities are affected by a change in the average exchange rate, upon conversion to Algonquin's reporting currency. Although a weaker Canadian dollar relative to the U.S. dollar has an impact on both revenue and expenses generated by its U.S. subsidiaries, Algonquin's foreign exchange forward contracts in place partially offset the impact on earnings (see Risk Management).

EBITDA in the three months ended September 30, 2009 totalled \$20.3 million as compared to \$22.2 million during the same period in 2008, a decrease of \$2.0 million or 8.8%. The decrease in EBITDA is primarily related to lower earnings from operations resulting from lower gas prices and reduced demand for steam in the Thermal Energy division and lower average energy rates earned by the Renewable Energy divisions U.S. facilities. A more detailed analysis of these factors is presented within the reconciliation of EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended September 30, 2009, net earnings totalled \$13.1 million as compared to a net loss of \$4.4 million during the same period in 2008. Net earnings per trust unit totalled \$0.17 for the three months ended September 30, 2009, as compared to net loss per trust unit of \$0.06 during the same period in 2008.

The increase in net earnings as compared to 2008 was primarily the result of gains of \$15.0 million due to unrealized mark to market gains on derivative financial instruments partially offset by losses on derivative financial instruments contracts settled in the period, as a result of increased interest rates and the stronger Canadian dollar.

Unrealized mark to market losses on derivative financial instruments resulting from changes in foreign exchange

rates relate to contract periods which extend to fiscal 2013. Unrealized mark to market losses on derivative financial instruments resulting from changes in interest rates relate to contract periods which extend to fiscal 2015. The following chart provides a summary of the period over period changes between realized and unrealized mark to market gains and losses of derivative financial instruments:

	Three months ended September 30		
	2009	2008	Change
Foreign Exchange Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	\$ (7,696)	\$ 4,126	\$ (11,822)
Realized loss/(gain) on derivative financial instruments	(77)	(1,428)	\$ 1,351
	<u>\$ (7,773)</u>	<u>\$ 2,698</u>	<u>\$ (10,471)</u>
	Three months ended September 30		
	2009	2008	Change
Interest Rate Swap Contracts:			
Unrealized mark to market loss/(gain) on derivative financial instruments	\$ (849)	\$ 2,353	\$ (3,202)
Realized loss/(gain) on derivative financial instruments	1,522	168	\$ 1,354
	<u>\$ 673</u>	<u>\$ 2,521</u>	<u>\$ (1,848)</u>
Derivative Financial Instruments Total:			
Unrealized mark to market loss/(gain) on derivative financial instruments	\$ (8,545)	\$ 6,479	\$ (15,024)
Realized loss/(gain) on derivative financial instruments	1,445	(1,260)	\$ 2,705
Total loss/(gain) on derivative financial instruments	<u>\$ (7,100)</u>	<u>\$ 5,219</u>	<u>\$ (12,319)</u>

In addition, net earnings for the three months ended September 30, 2009 increased by \$1.7 million as a result of reduced interest expense due to lower rates on Algonquin's variable interest rate debt booked in the period, \$1.0 million due to higher earnings on portfolio investments and \$1.0 million due to non-cash gains resulting from the weaker Canadian dollar as compared to the same period in 2008. These items were partially offset by \$0.9 million resulting from increased minority interest gains at the St. Leon facility primarily due to unrealized gains on financial instruments, \$2.2 million due to lower earnings from operating facilities, \$0.4 million due to increased amortization expense, and \$0.8 million due to increased administrative expenses as compared to the same period in 2008.

During the three months ended September 30, 2009, cash provided by operating activities totalled \$14.4 million or \$0.18 per trust unit as compared to cash provided by operating activities of \$21.1 million, or \$0.27 per trust unit during the same period in 2008. The change in cash provided by operating activities after changes in working capital in the three months ended September 30, 2009, is primarily due to increased realized losses from derivative instruments and decreased cash flow from operating facilities, as compared to the same period in 2008.

Outlook

The Power Generation & Development division is expecting at or below long term average resource conditions in the fourth quarter of 2009. It is expecting that lower than historic weighted average energy rates at Algonquin's

U.S. renewable facilities to persist through the fourth quarter of 2009 due to the overall effect the economic slow down has had on energy prices in those markets. Throughput at the Energy-From-Waste (“EFW”) facility is expected to continue at the levels experienced in 2008. The Windsor Locks and Sanger facilities are expected to operate below Algonquin’s expectations for the fourth quarter of 2009 due to the lower than expected natural gas costs. There is also reduced demand for steam from the steam hosts at each of these facilities due to overall economic slowdown. Algonquin’s power development team will continue to pursue new opportunities for power generation projects in both Canada and the U.S. The Power Generation and Development divisions will continue to focus on cost containment and productivity improvement measures that will maximize margins and EBITDA throughout 2009.

The Utility Services business unit is expecting limited organic growth due to the continued slowdown in the U.S. housing market. Utility Services has filed rate cases at a number of its utilities and will continue to process these rate cases throughout the remainder of 2009. These rate cases are discussed in further detail within this MD&A (see UTILITY SERVICES: Outlook). An exact determination of increased revenues from all rate case applications is not possible at this time as the timing of conclusion to the rate cases and the final decision on rate increases are determined by the regulator. As a result of delays in the progress of rate cases through the regulatory processes, the Utility Services division now anticipates that approximately \$7 million of additional revenue from rate cases will be achieved in 2010 but the full annualized increase in revenues determined through the rate case processes will still be achieved in 2011.

The regulatory reviews of the rates and tariffs for these facilities are expected to conclude in the second half of 2009 and early 2010, with the new rates and tariffs going into effect in the remainder of 2009 and the first half of 2010, depending on the state in which the facility operates. The business unit will also continue to consider accretive water and wastewater utility acquisition opportunities, as well as acquisitions in other regulated utilities, such as electricity distribution.

In all of its business units, Algonquin is committed to the growth and development of Algonquin’s team through various training programs, challenging assignments and learning opportunities. In addition, Algonquin ensures continuous environmental, health and safety training for its operations and maintenance staff. Algonquin will continue to invest in information technology to reduce operating and administrative costs.

Overall, Algonquin’s business units will focus on priorities that enable Algonquin to be an innovative, respected and socially responsible participant in the renewable energy, power and utility businesses and to maximize value for Algonquin in the current state of the financial markets. With a mix of complementary regulated and non-regulated businesses, Algonquin strives to enhance unitholder value through stable cash flows, sustainable cash distributions and a managed risk profile.

Algonquin attributes the reduced average energy rates to the overall effect the economic slow down has had on energy prices primarily in New York and New England where its hydro electric plants sell merchant power. Algonquin attributes lower revenue at its Sanger and Windsor facilities to lower gas prices and to lower demand from the steam hosts resulting from the overall economic slow down.

Algonquin also expects lower demand from the steam hosts at its thermal facilities due to the economic slowdown will continue to persist in the fourth quarter along with the current low gas prices.

POWER GENERATION & DEVELOPMENT

Renewable Energy Division

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Performance (MW-hrs sold)				
Quebec Region	71,675	84,202	226,250	241,305
Ontario Region	32,875	34,904	109,050	114,053
Manitoba Region	76,600	79,167	274,875	271,807
New England Region	19,850	15,295	65,525	63,884
New York Region	17,300	13,567	70,250	66,539
Western Region	22,200	25,708	47,325	56,260
Total	240,500	252,843	793,275	813,848
Revenue				
Energy sales	\$ 15,198	\$ 16,878	\$ 51,623	\$ 56,374
Expenses				
Operating expenses	(4,932)	(5,304)	(15,660)	(15,855)
Other income	241	193	793	970
Division operating profit (including other income)	\$ 10,507	\$ 11,767	\$ 36,756	\$ 41,489

As Algonquin's facilities in the New York and New England region are primarily subject to market rates, the average revenue earned per MW-hr sold can vary significantly from the same period in the prior year. Algonquin's facilities in the other regions are subject to varying rates, by facility, as set out in each facility's individual power purchase agreement ("PPA"). As such, while most of Algonquin's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities which earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

2009 Nine Month Operating Results

For the nine months ended September 30, 2009 the Renewable Energy division produced 793,275 MW-hrs of electricity, as compared to 813,848 MW-hrs produced in the same period in 2008, a decrease of 2.5%. The production level in 2009, while slightly lower than the previous year still represents production levels above long term averages. The production in the nine months ended September 30, 2009 represents sufficient renewable energy to supply the equivalent of 58,750 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 436,000 tons of CO₂ gas was prevented from entering the atmosphere in the first three quarters of 2009.

During the nine months ended September 30, 2009, the division generated electricity equal to 106% of long term projected average resources (wind and hydrology) as compared to 107% during the same period in 2008. In the first nine months of 2009, a number of regions experienced resources at significantly higher levels than long term average, including the Quebec region which was 11% above long term averages, the New England region, which was 38% above long term averages and the New York region, which was 9% above long term averages. The Western region experienced results 12% below long term average resources. All other regions experienced results in line with or above long term average resources in the nine months ended September 30, 2009.

For the nine months ended September 30, 2009, revenue from energy sales in the Renewable Energy division totalled \$51.6 million, as compared to \$56.4 million during the same period in 2008. Revenue from Algonquin's U.S. facilities decreased \$3.8 million due to a decrease in weighted average energy rates of approximately 40% in the New England and New York regions, partially offset by an increase of \$0.5 million due to higher than average hydrology, as compared to the same period in 2008. Revenue from Algonquin's Canadian hydroelectric facilities decreased \$0.1 million due to a decrease in weighted average energy rates of approximately 0.3% and \$1.6 million due to lower average hydrology, as compared to the same period in 2008. Revenue from Algonquin's wind farm increased \$0.2 million due to a stronger wind resource, offset by \$0.2 million due to a decrease in weighted average energy rates of approximately 1.2%, as compared to the same period in 2008. The division reported increased revenue of \$0.8 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the nine months ended September 30, 2009, operating expenses totalled \$15.7 million, as compared to \$15.9 million during the same period in 2008, a decrease of \$0.2 million. Operating expenses were impacted by \$0.8 million of decreased variable operating costs tied to lower revenue associated with facilities located in the U.S., \$0.2 million as a result of lower repair and maintenance expenses incurred in the period, partially offset by increased operational and administrative expenses of \$0.4 million, as compared to the same period in 2008. Operating expenses include costs of \$1.2 million associated with the pursuit of various growth and development activities, a reduction of \$0.4 million as compared to the same period in 2008. The division reported increased expenses of \$0.7 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the nine months ended September 30, 2009, operating profit totalled \$36.8 million, as compared to \$41.5 million during the same period of 2008, representing a decrease of 11.4%. For the quarter ended September 30, 2009, operating profit did not meet Algonquin's expectations primarily due to lower weighted average energy rates in the U.S.

2009 Third Quarter Operating Results

For the quarter ended September 30, 2009 the Renewable Energy division produced 240,500 MW-hrs of electricity, as compared to 252,843 MW-hrs produced in the same period in 2008, a decrease of 4.8%. The level of production in 2009 represents sufficient renewable energy to supply the equivalent of 53,500 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 132,500 tons of CO₂ gas was prevented from entering the atmosphere in the third quarter of 2009.

During the quarter ended September 30, 2009, the division generated electricity equal to 111% of long term projected average resources (wind and hydrology) as compared to 115% during the same period in 2008. A number of regions experienced resources at significantly higher levels than long term average, including the Quebec region which was 12% above long term averages, the New York region, which was 48% above long term averages and the New England region, which was 175% above long term averages. The Western region experienced results 11% below long term average resources. All other regions experienced results in line with or above long term average resources in the quarter ended September 30, 2009.

For the quarter ended September 30, 2009, revenue from energy sales in the Renewable Energy division totalled \$15.2 million, as compared to \$16.9 million during the same period in 2008. Revenue from Algonquin's U.S. facilities decreased \$1.1 million due to a decrease in weighted average energy rates of approximately 45% in the New England region, partially offset by \$0.7 million due to increased average hydrology, as compared to the same period in 2008.

Revenue from Algonquin's wind farm increased \$0.2 million due to an increase in weighted average energy rates of approximately 3.4%, offset by \$0.2 million due to a weaker wind resource, as compared to the same period in 2008. Revenue from Algonquin's Canadian facilities decreased \$1.2 million due to lower energy production, as compared to the same period in 2008. The division reported increased revenue of \$0.1 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the quarter ended September 30, 2009, operating expenses totalled \$4.9 million, as compared to \$5.3 million during the same period in 2008, a decrease of \$0.4 million. Operating expenses were impacted by \$0.1 million of decreased variable operating costs tied to lower revenue associated with facilities located in the U.S., as compared to the same period in 2008. Operating expenses include costs of \$0.4 million associated with the pursuit of various growth and development activities, as compared to \$0.7 million in the same period in 2008. The division reported increased expenses of \$0.1 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the quarter ended September 30, 2009, operating profit totalled \$10.5 million, as compared to \$11.8 million during the same period of 2008, representing a decrease of 10.7%. For the quarter ended September 30, 2009, operating profit did not meet Algonquin's expectations primarily due to lower weighted average energy rates in the U.S.

Divisional Outlook – Renewable Energy

The Renewable Energy division is expected to perform at or below long term average resource conditions in the fourth quarter of 2009 with the exception of the New York region where Algonquin anticipates at or above long term average resource conditions. The facilities in the New York and New England regions are expected to continue to experience reduced market rates as compared to the rates experienced in 2008 as a result of a decrease in demand for electricity due to the current economic climate in those markets.

As a result of certain legislation passed in Quebec (Bill C93), Algonquin's Renewable Energy division is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. Algonquin anticipates incurring minimal costs during the remainder of 2009 to complete the required assessments in order to determine the work required and estimate capital cost of compliance with the legislation. Upon completion of these assessments, Algonquin is required to submit plans for undertaking any remedial measures that are identified to comply with the legislation. As a result of nine completed and two partially completed assessments, Algonquin has estimated capital expenditures of approximately \$17.8 million related to compliance with the legislation. The timing of when the actual capital costs need to be made is determined as part of the technical assessments. Algonquin anticipates that these expenditures will be invested over the next five years as follows:

	Total	2009	2010	2011	2012	2013
Estimated Bill C-93 Capital Expenditures	17,830	5	6,240	6,035	3,050	2,500

The majority of these capital costs are associated with the Donnacona, St. Alban and Mont-Laurier facilities. Algonquin does not anticipate any significant impact on power generation or associated revenue while the dam safety work is ongoing. Algonquin continues to explore several alternatives to mitigate the capital costs of the modifications, including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications. As a result of the continuing assessments of alternatives, Algonquin does not expect to incur any significant Bill C-93 Capital Expenditures in the remainder of 2009 and that the capital expenditure plan continues to meet the provisions of Bill C-93.

POWER GENERATION & DEVELOPMENT

Thermal Energy Division

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Performance (MW-hrs sold)	143,640	147,543	424,023	452,884
Performance (tonnes of waste processed)	41,914	41,815	118,913	118,880
Revenue				
Energy sales	\$ 14,941	\$ 24,026	\$ 48,390	\$ 61,153
Less:				
Cost of Sales – Fuel *	(5,521)	(12,796)	(21,293)	(33,120)
Net Energy Sales Revenue	\$ 9,420	\$ 11,230	\$ 27,097	\$ 28,033
Waste disposal sales	3,821	4,098	10,682	11,709
Other revenue	928	902	3,303	2,658
Total net revenue	\$ 14,169	\$ 16,230	\$ 41,082	\$ 42,400
Expenses				
Operating expenses *	(7,581)	(8,233)	(23,661)	(23,698)
Interest and other income	1,157	853	2,877	2,797
Division operating profit (including interest and dividend income)	\$ 7,745	\$ 8,850	\$ 20,298	\$ 21,499

* Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities, where changes in these costs are passed to the customer in the energy price.

2009 Nine Month Operating Results

For the first three quarters, the EFW facility processed 118,913 tonnes of municipal solid waste as compared to 118,880 tonnes processed in the same period of 2008. This level of production resulted in the diversion of approximately 81,500 tonnes of waste from landfill sites in the first nine months of 2009.

During the nine months ended September 30, 2009, the business unit produced 424,023 MW-hrs of energy as compared to 452,884 MW-hrs of energy in the comparable period of 2008, a decrease of 6.4%. The business units' performance decreased by 6,400 MW-hrs at the Sanger facility resulting from power curtailment by Pacific Gas and Electric Company ("PG&E") due to line loading issues on the utility side and 8,100 MW-hrs at the Windsor Locks facility due to reduced demand for steam from its steam host customer, as compared to the same period in 2008. The overall decrease in energy production at the EFW facility is due to steam generated by the incineration process at the facility now being utilized by BCI for steam sales to a nearby industrial customer rather than being used to generate electricity. During the nine months ended September 30, 2009, the business unit's BCI steam sales facility was operating for the full period having reached commercial operation in June 2008. Although this has resulted in the decrease in electrical generation from EFW's steam turbine of 14,500 MW-hrs, the decrease was more than offset by the new steam sales by BCI. Throughput at the EFW facility remained consistent with the same period in 2008.

For the nine months ended September 30, 2009, gross revenue in the Thermal Energy division totalled \$62.4 million, as compared to \$75.5 million during the same period in 2008, a decrease of \$13.1 million. For the nine

months ended September 30, 2009, net energy sales revenue at the Thermal Energy division totalled \$27.1 million, as compared to \$28.0 million during the same period in 2008, a decrease of \$0.9 million. The decrease in revenue from net energy sales, as compared to the first nine months of 2008, was primarily due to the following: a decrease of \$4.8 million as a result of decreased energy rates, in part due to lower natural gas prices, and \$1.1 million as a result of decreased production at the Sanger facility as compared to the same period in 2008; decreased revenue at the Windsor Locks facility of \$11.2 million as a result of lower energy rates, in part due to lower natural gas prices, and \$1.0 million as a result of decreased demand for steam production as compared to the same period in 2008; decreased revenue of \$1.0 million at the LFG facilities primarily as a result of lower energy rates; and \$0.9 million at the EFW facility as a result of a portion of the steam generated by the incineration processes being used by BCI instead of being used to generate electricity. These decreases were partially offset by an increase of \$2.6 million as a result of the BCI steam sales facility achieving commercial operation in June 2008, as compared to the same period in 2008. The division reported increased revenue of \$5.1 million from operations as a result of the weaker Canadian dollar, as compared to the same period in 2008.

Revenue from waste disposal sales for the nine months ended September 30, 2009 totalled \$10.7 million, as compared to \$11.7 million during the same period in 2008, a decrease of \$1.0 million. The facility earned lower average rates for each tonne of waste processed in the quarter, primarily the result of the arrangement to process higher priced airline waste at the facility ceasing in December 2008.

For the nine months ended September 30, 2009, fuel costs at Sanger and Windsor Locks totalled \$21.3 million, as compared to \$33.1 million during the same period in 2008, a decrease of \$11.8 million. Natural gas expense at Sanger decreased \$4.6 million (59%), primarily the result of a 56% decrease in the price for natural gas as compared to the same period in 2008. In addition, production decreased 6%, primarily as a result of production curtailments by Pacific Gas and Electric Company ("PG&E"), decreasing the volume of natural gas used in ongoing operation of the facility as compared to the same period in 2008. Natural gas expense at the Windsor Locks facility decreased \$9.8 million (40%), primarily the result of a 39% decrease in the price for natural gas as compared to the same period in 2008. The division reported increased fuel costs of \$2.6 million as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the nine months ended September 30, 2009, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled \$23.7 million, consistent with the same period in 2008. Operating expenses for the period were impacted by decreased operating expenses of \$0.5 million at the EFW facility as a result of lower natural gas and other operating costs and \$0.4 million primarily due to decreased repair and maintenance costs at the Valley Power facility, as compared to the prior period. Expenses at the LFG facilities decreased \$1.7 million due to lower operating, royalty, repair, maintenance and natural gas expenses as compared to the same period in 2008. In 2008 expenses at the LFG facilities included \$0.6 million of costs associated with its investment in the landfill gas tax credit program which did not occur in 2009. These decreases were partially offset by increased expenses at the Windsor Locks facility primarily due to \$0.4 million in costs associated with compliance with the greenhouse gas initiatives and \$0.9 million of operating costs of the BCI steam facility as compared to the same period in 2008. The reported operating costs at the BCI facility exclude the cost of purchasing steam from the EFW facility as this is eliminated upon consolidation. The division reported increased operating expenses of \$1.4 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the nine months ended September 30, 2009, the Thermal Energy division's operating profit totalled \$20.3 million, as compared to \$21.5 million during the same period in 2008, a decrease of \$1.2 million or 5.6%. Operating profit in the Thermal Energy division did not meet Algonquin's overall expectations for the nine months ended

September 30, 2009, due to weaker gas prices and lower demand for steam from the division's co-generation assets resulting from the current economic slow down in the U.S.

2009 Third Quarter Operating Results

In the third quarter of 2009, the EFW facility processed 41,914 tonnes of municipal solid waste as compared to 41,815 tonnes processed in the same period of 2008, an increase of 0.2%. This level of production resulted in the diversion of approximately 29,500 tonnes of waste from landfill sites in the third quarter of 2009.

During the quarter ended September 30, 2009, the business unit produced 143,640 MW-hrs of energy as compared to 147,543 MW-hrs of energy in the comparable period of 2008, a decrease of 2.6%. During the quarter ended September 30, 2009, the business unit's performance decreased by 1,700 MW-hrs at the Windsor Locks facility, 1,400 MW-hrs at the landfill-gas ("LFG") facilities, partially offset by increased energy production of 700 MW-hrs at the Sanger facility, as compared to the same period in 2008. During the quarter ended September 30, 2009, the business unit's BCI steam facility was operating for the full quarter having reached commercial operation in June 2008. This resulted in the decrease in electrical generation from EFW's steam turbine of 2,000 MW-hrs, offset by the new steam sales by BCI. Throughput at the EFW facility was consistent with the same period in 2008.

For the quarter ended September 30, 2009, revenue in the Thermal Energy division totalled \$19.7 million, as compared to \$29.0 million during the same period in 2008, a decrease of \$9.3 million. For the quarter ended September 30, 2009, net energy sales revenue at the Thermal Energy division totalled \$9.4 million, as compared to \$11.2 million during the same period in 2008, a decrease of \$1.8 million. The decrease in revenue from energy sales, as compared to the third quarter of 2008, was primarily due to a decrease of \$2.2 million as a result of decreased energy rates, in part due to lower natural gas prices, partially offset by \$0.2 million as a result of increased production at the Sanger facility, as compared to the same period in 2008. Revenue at the Windsor Locks facility declined \$6.6 million as a result of decreased energy rates, in part due to lower natural gas prices, and \$0.2 million as a result of decreased demand for steam production, as compared to the same period in 2008. The offsetting reduction in natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. In addition, revenue declined \$0.5 million at the LFG facilities as a result of lower energy rates and lower energy production and \$0.1 million at the EFW facility as compared to the same period in 2008. The division reported increased revenue of \$0.3 million from operations as a result of the weaker Canadian dollar, as compared to the same period of 2008.

Revenue from waste disposal sales for the quarter ended September 30, 2009 totalled \$3.8 million, as compared to \$4.1 million during the same period in 2008. The facility earned lower average rates for each tonne of waste processed in the quarter, primarily the result of the arrangement to process higher priced airline waste at the facility ceasing in December 2008.

For the quarter ended September 30, 2009, fuel costs at Sanger and Windsor Locks totalled \$5.5 million, as compared to \$12.8 million during the same period in 2008, a decrease of \$7.3 million. Natural gas expense at Sanger decreased \$1.6 million (63%), primarily the result of a 64% decrease in the price for natural gas as compared to the same period in 2008. Natural gas expense at the Windsor Locks facility decreased \$5.7 million (42%), primarily the result of a 59% decrease in the price for natural gas as compared to the same period in 2008.

For the quarter ended September 30, 2009, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled \$7.6 million, as compared to \$8.2 million during the same period in 2008, a decrease of \$0.6 million. The decrease in operating expenses for the quarter was primarily due to reduced operating costs of \$0.7 million at the LFG facilities resulting from lower repair, maintenance, royalty and operating expenses as well as \$0.2 million

in lower consumables and utility expenses at the hydro-mulch facility. These decreases were partially offset by increased operating expenses of \$0.1 million in additional costs associated with compliance with the greenhouse gas initiative at Windsor Locks and \$0.3 million of increased expenses at the EFW facility primarily related to increased repair and maintenance and utility costs as compared to the same period in 2008. The division reported increased operating expenses of \$0.1 million from U.S. operations as a result of the weaker Canadian dollar as compared to the same period in 2008.

For the quarter ended September 30, 2009, the Thermal Energy division's operating profit totalled \$7.7 million, as compared to \$8.9 million during the same period in 2008, representing a decrease of 12.5%. Operating profit in the Thermal Energy division did not meet Algonquin's overall expectations for the quarter ended September 30, 2009, due to weaker gas prices and lower demand for steam from the Division's co-generation assets resulting from the current economic slow down in the U.S.

Divisional Outlook – Thermal Energy

The EFW facility is expected to operate in line with Algonquin's expectations during the fourth quarter of 2009. Operations at the EFW facility have improved due in part to a new enhanced design for boiler tubes installed in 2008 and this improved performance is expected to continue through 2009.

The Thermal Energy division's Windsor Locks and Sanger facilities are expected to operate below Algonquin's expectations for the fourth quarter of 2009 due to the lower than expected natural gas costs and reduced demand for steam resulting from the continuing economic slow down in the U.S. The Windsor Locks facility will experience lower sales of electricity and steam during the fourth quarter due to weaker demand from the Ahlstrom mill.

POWER GENERATION & DEVELOPMENT

Development Division

The Development division works to identify, develop and construct new, renewable and efficiency energy generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of Algonquin's existing facilities. Development is focused on projects in North America with a commitment to working proactively with all stakeholders, including local communities. The Development division is led by five full time employees based out of Algonquin's head office. In addition, the division has access to and support from all of the available resources and experience throughout Algonquin to assist it in the development of projects, including finance, engineering, technical services, as well as environmental and regulatory compliance. The division also utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains those as required from the financial, legal, engineering, technical, and construction sectors.

The Development division may also create opportunities through the acquisition of operating assets with accretive characteristics and prospective projects that are at various stages of development. The current economic climate is also opening up opportunities for Algonquin to acquire third party development projects on attractive terms that require the experience and financial resources that Algonquin has at its disposal. The business strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing cash flows in order to achieve a high return on invested capital.

Algonquin's approach to project development is to maximize the utilization of internal resources while minimizing external costs to move development projects forward to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements

and uncertainties of a project include, but are not limited to, signing a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that Algonquin will actually begin construction of the project.

Current Development Projects

Red Lily

Algonquin continues to advance the Red Lily Wind Project in south-eastern Saskatchewan (the “Project”) jointly with an unrelated third party. In July 2008, a 25 MW PPA for the first phase of the Project (“Phase I”) was executed with SaskPower after Phase I was successfully bid into a SaskPower Environmentally Preferred Power Strategy Request for Proposal. In June 2009, Algonquin and Natural Resources Canada (“NRC”) executed a Contribution Agreement under the ecoENERGY for Renewable Power Program for Phase I, securing funding for the project in advance of the expectation of the program being fully subscribed later in 2009. Algonquin has submitted to NRC the Environmental Impact Assessment documentation for review in relation to obtaining funding under the federal ecoENERGY program and is following up with NRC, as the lead agency, on comments received from other agencies. Notably, on April 13, 2009 Saskatchewan Environmental Assessment Branch confirmed that Algonquin had satisfied the requirements under the Provincial Environmental Assessment Act for Phase I. In addition to the focused effort on Phase I, Algonquin has secured additional property and is assessing the viability of an expanded project. The viability of the expanded project will be conditional upon actual operating results from Phase I.

Successful development of wind projects such as Red Lily are subject to significant risks and uncertainties including the ability to obtain financing on acceptable terms within deadlines imposed by the utility, reaching agreement with any other external parties involved in the project, currency fluctuations affecting the cost of major capital components such as wind turbines, price escalation for construction labour and other construction inputs, construction risk that the project is built without mechanical defects and is completed on time and within budget estimates. In the event the Project is developed, it is currently estimated to require 16 turbines with a capital investment of approximately \$60 - \$65 million. Annual energy production from the wind farm is estimated to be 92,000 MW-hrs and annual gross revenue is estimated to be \$8.9 million. The current estimate of the earliest time the Project could be completed is March 31, 2011.

Windsor Locks

The Windsor Locks facility has two key agreements. The first agreement is the PPA with Connecticut Light & Power (“CL&P”) which expires in April 2010. The second agreement is the Energy Services Agreement with Ahlstrom Windsor Locks, LLC (“Ahlstrom”), a leading paper and non woven materials manufacturer, which, if not further extended by mutual agreement, will continue until 2017. The expiration of the CL&P PPA will impact future operations. Algonquin is reviewing two options with regards to the Windsor Locks facility. The first option involves maximizing net revenue from existing equipment (“Existing Equipment Option”). The second option involves re-powering the facility with equipment to match the current steam and electrical demand of Ahlstrom in addition to maintaining the existing equipment which will qualify for capacity payments and may be able to generate additional revenue by providing ancillary services to the Independent System Operator New England (“ISO-NE”) or peaking revenue when supported by a positive spark-spread market condition (“Re-Powering Option”).

The Existing Equipment Option involves servicing the steam and power requirements of Ahlstrom in addition to providing a portfolio of ancillary services to other customers without investing in new capital and could be implemented coincident with the expiry of the PPA with CL&P. The portfolio of services may involve multiple customers and could include selling approximately 10MW of electrical capacity to an adjoining industrial customer

in a “behind-the-meter” configuration, selling between 10MW and 40MW of electrical capacity to a local utility or providing ancillary services such as “spinning reserves” to the ISO-NE. At this point the most certain of this portfolio of services is the thirty minute operating reserve (“TMOR”) which has cleared at US \$14 thousand per mega watt month for the last 7 forward reserve procurement periods (two periods annually). The Development division currently anticipates operating cash flow at the Windsor Locks facility for 2010 to be approximately U.S. \$4.5 million under the Existing Equipment Option compared to an historical cash flow of approximately U.S. \$8.0 million. This operating cash flow estimate assumes participation in the summer 2010 and the winter 2010/2011 forward reserve auctions.

The Re-Powering Option involves installing a new combustion gas turbine sized to meet the electrical and steam requirements of Ahlstrom. Preliminary engineering and environmental permitting for the re-powered facility has been initiated. Algonquin has applied for and expects to be eligible to receive a one-time non-recurring grant from the Department of Public Utility Control, State of Connecticut equivalent to US \$450/KW to a maximum of US \$6.6 million to offset the cost of re-powering. In addition to installing the new combustion gas turbine, Algonquin will maintain the existing equipment. Any investment in new capital will be based on an assessment of the incremental earnings generated by the additional investment after applying applicable grants and whether those incremental earnings achieve Algonquin’s return expectations. Proceeding with this option does not preclude proceeding with the Existing Equipment Option.

Other

Algonquin has completed preliminary engineering and a financial feasibility analysis on a 12 MW combined cycle high efficiency thermal energy generation project located in Ontario. Algonquin believes this project is an excellent fit for the Minister of Energy and Infrastructure’s Directive to procure electricity from combined heat and power projects.

Future Development Projects – Greenfield Projects

There are a number of future greenfield development projects which are being actively pursued by the Development division. These projects encompass several new wind energy projects having a potential generation capacity of over 250 MW, hydroelectric projects at different stages of investigation, and thermal energy generation projects. The projects being examined are located both in Canada and the United States.

Algonquin owns the rights, including land options, meteorological towers and historical wind data related to a potential 80 MW Canadian wind project. In the event the project is developed, it is currently estimated to require an investment of up to \$250 million and would be constructed after environmental approvals are granted, a process that has been initiated and is currently estimated to require 2 to 3 years to complete.

In 2008, Algonquin made a strategic decision to maintain land option agreements for two wind projects in Quebec in anticipation of future provincial tenders. In May 2009, Hydro Quebec released details in relation to a tender request for wind projects of a 25 MW maximum size. In addition, Algonquin has maintained a relationship with a development co-operative comprised of landowners and other small investors for the potential development of a third project in response to the expected call for tender.

Discussions with the Ontario Power Authority indicate that energy procurement initiatives will be positively influenced by the Green Energy Act (“GEA”) which received Royal Assent on May 14, 2009. Government agencies are working to develop the regulations, tools and guidelines required to fully implement the legislation. The Green Energy Act is intended to provide the catalyst for the development of 50,000 new green economy jobs and is viewed by Algonquin as positive for the development of renewable energy in Ontario. In anticipation of the

regulations coming into effect, the Development division is maintaining relationships with potential partners for the development of a number of projects that could qualify under anticipated procurement initiatives undertaken by the Ontario Power Authority in accordance with the Green Energy Act. In addition, Algonquin has applied to become applicant of record for three crown land sites under the Ministry of Natural Resources wind power site release program.

Each project being contemplated is subject to a significant level of due diligence and financial modeling to ensure it satisfies return and diversification objectives established for the Development division. Accordingly, the likelihood of proceeding with some or all of these projects depends on the outcome of due diligence, material contract negotiations, the structure of future calls for tender, and request for proposal programs. To maximize Algonquin's opportunities for development, new renewable and high efficiency thermal energy generating facilities are being pursued utilizing a variety of technologies and in diverse geographic locations.

Future Development Projects – Existing Facilities

The following sets out a summary of potential development projects at existing facilities which are being examined by the Development division.

Renewable Energy

The St. Leon Wind Project achieved commercial operation status under its PPA with the Manitoba Hydro Electric Board in June 2006, and has been performing at or above expected levels of production. Algonquin is exploring multiple options to continue to build on the success of this project including pursuing a future adjacent project and/or pursuing an increase in the installed capacity of the existing facility. The projects being reviewed have a potential generation capacity of over 85 MW. In the event these projects are developed, it is currently estimated to require an investment of approximately \$250 million.

Thermal Energy

The EFW facility in the Thermal Energy division of the Power Generation & Development business unit is designed to incinerate over 500 tonnes per day of municipal solid waste from the Region of Peel to produce steam that is used in the production of electricity and to supply the internal steam load for a nearby recycled paper board manufacturing mill. Algonquin established BCI to operate the required facilities to supply steam to the nearby paper board customer and pursue additional steam load customers.

The Development division is currently reviewing several proposals at the EFW facility to expand its power generation and waste processing throughput capacity. Throughput capacity could be expanded by between 40,000 and 100,000 tonnes annually depending on the proposal that is selected. If the expansion is pursued, depending on the alternative chosen, an investment of between \$60 million to \$250 million would be required. Algonquin is currently evaluating the feasibility of an expanded facility including associated capital and operating costs and financing terms. Algonquin is also engaged in discussions with the Region of Peel to establish a new long term contract for a reliable supply of municipal solid waste.

Divisional Outlook - Development

Algonquin believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects. Most recently the Ontario government received Royal Assent to enact the Green Energy Act. Embedded within the Green Energy Act is the obligation of the Ontario Power Authority to issue standard pricing for electricity from renewable sources under a Feed-in Tariff (FIT). The final FIT pricing was announced on September 24th. Included within this legislation is the requirement for the responsible power

purchase authority to grant priority and obligatory purchase of green energy projects, and an obligation for all utilities to grant priority grid access to green energy projects. The intention of the legislation is to make development of renewable energy projects significantly easier than the prior process of formal bids in response to requests for proposals from the responsible power authority.

UTILITY SERVICES

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Number of				
Wastewater connections	34,294	34,033	34,294	34,033
Wastewater treated (millions of gallons)	475	450	1,425	1,400
Water distribution connections	36,841	36,108	36,841	36,108
Water sold (millions of gallons)	1,900	1,800	4,500	4,300
Assets for regulatory purposes	192,348	171,215	192,348	171,215
Revenue				
Wastewater treatment	\$ 5,263	\$ 4,710	\$ 15,919	\$ 13,734
Water distribution	4,826	4,348	13,474	11,270
Other Revenue	133	122	432	393
	\$ 10,222	\$ 9,180	\$ 29,825	\$ 25,397
Expenses				
Operating expenses	(6,185)	(5,664)	(18,182)	(15,202)
Other income	1,448	-	1,411	47
Business Unit operating profit (including other income)	\$ 5,485	\$ 3,516	\$ 13,054	\$ 10,242

Algonquin reports total connections, inclusive of vacant connections rather than customers. Utility Services had 34,294 wastewater connections as at September 30, 2009, as compared to 34,033 as at September 30, 2008, an increase of 261 in the period or 0.8%. Utility Services had 36,841 water distribution connections as at September 30, 2009, as compared to 36,108 as at September 30, 2008, an increase of 733 in the period or 2.0%. Total connections include approximately 2,025 vacant wastewater connections and 1,375 vacant water distributions connections. Utility Services' marginal change in water distribution and wastewater treatment customer base during the period continues to primarily relate to limited organic growth at the division's facilities resulting from the slow down in U.S. new residential home sales in areas served by the division.

Utility Services has investments in regulatory assets of \$192.3 million across four states as at September 30, 2009, as compared to \$171.2 million as at September 30, 2008 and has active proceedings in Texas and Arizona to allow it to earn its full regulatory return on its investment in regulatory assets.

2009 Nine Month Operating Results

During the nine months ended September 30, 2009, Utility Services provided approximately 4.5 billion U.S. gallons of water to its customers, treated approximately 1.4 billion U.S. gallons of waste-water and sold approximately 375 million U.S. gallons of treated effluent.

For the nine months ended September 30, 2009, Utility Services' revenue totalled \$29.8 million as compared to \$25.4 million during the same period in 2008. Revenue from wastewater treatment totalled \$15.9 million, as compared to \$13.7 million during the same period in 2008, an increase of \$2.2 million. Revenue from water distribution totalled \$13.5 million, as compared to \$11.3 million during the same period in 2008, an increase of \$2.2 million. Utility Services reported increased revenue from operations of \$3.9 million in the third quarter of 2009 as a result of the weaker Canadian dollar as compared to the same period in 2008. Excluding the impact of foreign exchange, revenue increased U.S. \$0.5 million or 2.2% as compared to the same period in 2008.

The nine month water distribution revenue was impacted by increased revenue of \$0.3 million at the Litchfield Park facility ("LPSCo") primarily due to higher commercial water sales, \$0.2 million due to organic growth and increased customer demand at 9 water distribution facilities and , \$0.4 million due to organic growth and increased customer demand at 7 wastewater treatment facilities, partially offset by decreased wastewater treatment revenue \$0.5 million resulting from a regulator imposed reduction in rates at the Gold Canyon facility as compared to the same period in 2008.

For the nine months ended September 30, 2009, operating expenses totalled \$18.2 million, as compared to \$15.2 million during the same period in 2008. Utility Services reported higher expenses from operations of \$2.5 million as a result of the weaker Canadian dollar, as compared to the same period in 2008. Excluding the impact of foreign exchange, overall expenses increased U.S. \$0.7 million or 5.0% as compared to the same period in 2008.

Operating expenses increased \$0.5 million as a result of increased operating costs, \$0.2 million in reduced contracted services expenses, \$0.2 million in reduced transportation costs and \$0.2 million in decreased repair and maintenance costs as compared to the same period in 2008. Included in expenses are \$0.6 million related to the prosecution of multiple rate cases in the period. These costs are being expensed for accounting purposes but are considered regulatory assets and Utility Services is entitled to earn a return on these costs as part of the current rate case proceedings.

For the nine months ended September 30, 2009, Utility Services earned other income of \$1.4 million on the disposition of excess land. During the comparable period in 2008, Utility Services did not dispose of any significant land or other assets.

For the nine months ended September 30, 2009, operating profit totalled \$13.1 million as compared to \$10.2 million during the same period in 2008. Excluding the gain on disposition of other assets, operating profits increased by 13.7%. Utility Services' operating profit exceeded Algonquin's expectations for the nine months ended September 30, 2009.

2009 Third Quarter Operating Results

During the quarter ended September 30, 2009, Utility Services provided approximately 1.9 billion U.S. gallons of water to its customers, treated approximately 475 million U.S. gallons of wastewater, and sold approximately 150 million U.S. gallons of treated effluent.

For the quarter ended September 30, 2009, Utility Services' revenue totalled \$10.2 million as compared to \$9.2 million during the same period in 2008. Revenue from wastewater treatment totalled \$5.3 million, as compared to \$4.7 million during the same period in 2008, an increase of \$0.6 million. Revenue from water distribution totalled \$4.8 million, as compared to \$4.3 million during the same period in 2008, an increase of \$0.5 million. Utility Services reported increased revenue from operations of \$0.8 million in the third quarter of 2009 as a result of the weaker Canadian dollar as compared to the same period in 2008. Excluding the impact of foreign exchange, revenue increased U.S. \$0.2 million or 2.5% as compared to the same period in 2008.

The third quarter water distribution revenue was impacted by increased revenue of \$0.1 million at the LPSCo facility primarily due to higher commercial water sales. There was no significant change in customer demand at the remaining water distribution facilities, as compared to the same period in 2008. The third quarter wastewater treatment revenue was primarily impacted by \$0.2 million resulting from a regulator imposed reduction in rates at the Gold Canyon facility. There was no significant change in customer demand at the remaining wastewater treatment facilities, as compared to the same period in 2008.

For the quarter ended September 30, 2009, operating expenses totalled \$6.2 million, as compared to \$5.7 million during the same period in 2008. Utility Services reported higher expenses from operations of \$0.5 million as a result of the weaker Canadian dollar, as compared to the same period in 2008. Excluding the impact of foreign exchange, overall expenses increased U.S. \$0.1 million or 1.5% as compared to the same period in 2008.

Operating expenses increased \$0.3 million as a result of increased operating costs, partially offset by \$0.2 million in reduced contracted services expenses, \$0.1 million in reduced transportation costs and \$0.3 million in decreased repair and maintenance costs as compared to the same period in 2008. Included in expenses are \$0.2 million related to the prosecution of multiple rate cases in the period. These costs are being expensed for accounting purposes but are considered regulatory assets and Utility Services is entitled to earn a return on these costs as part of the current rate case proceedings.

For the quarter ended September 30, 2009, Utility Services earned other income of \$1.4 million on the disposition of excess land assets. During the comparable period in 2008, Utility Services did not dispose of any significant land or other assets.

For the quarter ended September 30, 2009, operating profit totalled \$5.5 million as compared to \$3.5 million during the same period in 2008. Excluding the gain on disposition of other assets, operating profits increased by 14.8%. Utility Services' operating profit exceeded Algonquin's expectations for the three months ended September 30, 2009.

Outlook – Utility Services

Notwithstanding the slowdown in the U.S. economy, Utility Services is not expecting any material reduction in customers in fiscal 2009. Utility Services continues to provide water distribution and wastewater treatment services, primarily in the southern and southwestern United States, in communities with a history of long term growth that provides opportunities for organic growth over the long term.

Utility Services is proceeding through the regulatory process with rate cases at a number of its facilities. The Black Mountain facility filed a rate case in December 2008 using a June 30, 2008 test year. The LPSCo facility filed a rate case in March 2009 using a September 2008 test year. The Rio Rico facility filed a rate case in May 2009, using a test year ended December 31, 2008. The Bella Vista, Northern Sunrise and Southern Sunrise facilities filed rate cases in August 2009 using a March 31, 2009 test year. All of these facilities are located in Arizona. Five Texas utilities filed rate cases in April 2009, and Woodmark in Texas filed in July 2009, all with test years ended December 31, 2008.

The following table sets out some particulars with respect to the status of the rate cases as at October 15, 2009:

Facility	Test Year Ending	Status of Rate Case Application	Estimated U.S. \$ Revenue Increase as Filed	Estimated Timing of Rate Increase
Arizona				
Black Mountain	Q2 2008	Company filed Rebuttal Testimony Oct 20th	\$ 0.9 million	Q1 2010
LPSCo	Q3 2008	Responding to interrogatories	\$ 12.5 million	Q2/Q3 2010
Rio Rico	Q4 2008	Responding to interrogatories	\$ 2.0 million	Q3 2010
Bella Vista, Northern and Southern Sunrise	Q1 2009	Filed	\$ 1.5 million	Q4 2010
Texas				
Texas Utilities (Silverleaf – 4 utilities)	Q4 2008	Public consultation period	\$ 1.2 million	Interim rates implemented October 2009
Tall Timbers	Q4 2008	Public consultation period	\$ 0.2 million	Interim rates implemented July 2009 Q1 2010
Woodmark	Q4 2008	Will be re-filed Nov 1 to include interim capital and operating expenses	\$ 0.1 million	

Rate cases ensure that a particular facility appropriately recovers its operating costs and earns the rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Algonquin monitors the rates of return on each of its utility investments to determine the appropriate time to file a rate case in order to ensure it earns the full regulatory approved rate of return on its investments.

In Texas, the Texas Commission on Environmental Quality (“TCEQ”) allows utilities’ customers 90 days from the effective date to object to the interim rates. If greater than 10% of a Texas utility’s customers object to the new rates, the utility must participate in a regulatory hearing process administered by the TCEQ in order to finalize the rates. If fewer than 10% of the customer base objects, rates are likely to be declared final. Any difference between the interim rates charged and collected and the final rates approved by TCEQ will be subject to a retroactive adjustment on the customer’s monthly bill.

In July 2009, Tall Timbers began charging new interim increased rates to customers in a portion of its service area as applied for in its rate case application. The interim rates are being contested by various homeowner associations in Tall Timbers service area affected by the increase. These rates are expected to be finalized before the end of the first quarter in 2010 as part of the normal regulatory process administered by the TCEQ. In October 2009, the Texas Silverleaf utility began charging interim rates based on its rate case applications.

In Arizona, the Arizona Corporate Commission requires a full regulatory process for all rate cases using a historic test year. It is anticipated that the regulatory review of the proposed rates and tariffs for the Arizona facilities would be completed in the remainder of 2009 and early 2010, with the new rates and tariffs in Arizona going into effect throughout 2010.

An exact determination of increased revenues from all rate case applications is not possible at this time as the timing of conclusion to the rate cases and the final decision on rate increases are determined by the regulator. As a result of delays in the progress of rate cases through the regulatory processes, the Utility Services division now anticipates that approximately \$7 million of additional revenue from rate cases will be achieved in 2010 but the full annualized increase in revenues determined through the rate case processes will still be achieved in 2011.

CORPORATE

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Corporate and other expenses:				
Administrative expenses	3,250	2,437	8,181	6,606
Management costs	213	224	639	669
Loss / (Gain) on foreign exchange	313	1,277	(1,003)	1,679
Interest expense	5,086	6,774	15,742	20,576
Interest, dividend and other Income	(2)	(764)	(52)	(817)
Loss (gain) on derivative financial instruments	(7,100)	5,219	(15,803)	6,622
Income tax expense (recovery)	(2,924)	2,874	(7,265)	4,746

OVERVIEW

2009 Nine Month Corporate and Other Expenses

During the nine months ended September 30, 2009, administrative expenses totalled \$8.2 million as compared to \$6.6 million in the same period in 2008. The expense increase in the nine months ended September 30, 2009 primarily relates to increased costs associated with added requirements to administer Algonquin's operations as well as additional legal and regulatory costs.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and do not impact current cash available for distribution. For purposes of evaluating divisional performance, Algonquin does not allocate the foreign exchange gains or losses to specific divisions as the change does not impact Algonquin's current cash position. For the nine months ended September 30, 2009, Algonquin reported a foreign exchange gain of \$1.0 million as compared to a loss of \$1.7 million during the same period in 2008. The nine months ended September 30, 2009 has experienced a decrease in value of the U.S. dollar of 13% which resulted in unrealized gains on Algonquin's U.S. denominated debt and working capital balances. The comparable period in 2008 experienced an increase in the value of the U.S. dollar of 7%, which resulted in unrealized losses on Algonquin's U.S. denominated debt. As at September 30, 2009, Algonquin had approximately \$32.8 million in U.S. dollar denominated debt.

For the nine months ended September 30, 2009, interest expense totalled \$15.7 million as compared to \$20.6 million in the same period in 2008. Decreased interest expense was primarily related to lower interest rates charged on Algonquin's variable interest rate credit facilities and lower average borrowings, as compared to the prior year.

Loss on derivative financial instruments consists of realized and unrealized mark to market losses on foreign exchange forward contracts and interest rate swaps during the period. The unrealized portion of any mark to market gains or losses on derivative instruments does not impact Algonquin's current cash position.

An income tax recovery of \$7.3 million was recorded in the first nine months of 2009, as compared to an expense

of \$4.7 million during the same period in 2008. The primary reasons for this recovery relates to the final determinations made for claiming discretionary deductions on 2008 income tax returns, the impact of which reduces future income tax liabilities previously recorded, tax losses due to bonus depreciation in the U.S. and lower operating profits from U.S. operations due to lower electricity prices and lower natural gas prices, partially offset by the reversal in the current year of unrealized losses on derivative financial instruments booked in the prior fiscal year. This resulted in an increased future tax recovery recorded in the nine months ended September 30, 2009. (see Risk Management – Changes to income tax laws).

2009 Third Quarter Corporate and Other Expenses

During the quarter ended September 30, 2009, administrative expenses totalled \$3.3 million, as compared to \$2.4 million in the same period in 2008. The expense increase in the three months ended September 30, 2009 primarily relates to costs associated with added requirements to administer Algonquin's operations as well as additional legal and regulatory costs.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and do not impact current cash available for distribution. For purposes of evaluating divisional performance, Algonquin does not allocate the foreign exchange gains or losses to specific divisions as the change does not impact Algonquin's current cash position. For the three months ended September 30, 2009, Algonquin reported a foreign exchange loss of \$0.3 million as compared to a loss of \$1.3 million during the same period in 2008. The three months ended September 30, 2009 has experienced a decrease in value of the U.S. dollar of 8% which resulted in unrealized losses on Algonquin's U.S. denominated debt and working capital balances. The comparable period in 2008 experienced an increase in the value of the U.S. dollar of 4%, which resulted in unrealized losses on Algonquin's U.S. denominated debt.

For the quarter ended September 30, 2009, interest expense totalled \$5.1 million as compared to \$6.8 million in the same period in 2008. Decreased interest expense was related to lower interest rates charged on Algonquin's variable interest rate credit facilities and lower average borrowings, as compared to the prior year.

Loss on derivative financial instruments consists of realized and unrealized mark to market losses on foreign exchange forward contracts and interest rate swaps during the quarter. The unrealized portion of any mark to market gains or losses on derivative instruments does not impact Algonquin's current cash position.

An income tax recovery of \$2.9 million was recorded in the three months ended September 30, 2009, as compared to an expense of \$2.9 million during the same period in 2008. The primary reasons for this recovery relates to tax losses due to bonus depreciation in the U.S. and lower operating profits from U.S. operations due to lower electricity prices and lower natural gas prices, partially offset by the reversal in the current year of unrealized losses on derivative financial instruments booked in the prior fiscal year. This resulted in an increased future tax recovery recorded in the three months ended September 30, 2009. (see Risk Management – Changes to income tax laws).

NON-GAAP PERFORMANCE MEASURES

Reconciliation of EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. Algonquin uses these calculations to monitor the amount of cash generated by Algonquin as compared to the amount of cash distributed by Algonquin. Algonquin uses EBITDA to assess the operating performance of Algonquin without the effects of depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. Algonquin believes that presentation of this measure will enhance an investor's understanding of Algonquin's operating performance. EBITDA is not

intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to EBITDA and provides additional information related to the operating performance of Algonquin. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Net earnings (loss)	\$ 13,078	(4,406)	\$ 32,623	\$ 2,057
Add:				
Income tax provision (recovery)	(2,924)	2,874	(7,265)	4,746
Interest expense	5,086	6,774	15,742	20,576
(Gain) / loss on derivative financial instruments	(7,100)	5,219	(15,803)	6,622
(Gain) / loss on foreign exchange	313	1,277	(1,003)	1,679
Amortization	11,513	11,067	34,533	32,310
Other	310	(569)	2,514	(1,218)
EBITDA	\$ 20,276	\$ 22,236	\$ 61,341	\$ 66,772

For the quarter ended September 30, 2009, EBITDA decreased by \$2.0 million compared to the same period in 2008. The decrease in EBITDA in the quarter ended September 30, 2009 is due to \$2.2 million in lower earnings from operations and \$0.8 million in increased administration expenses, partially offset by \$1.0 million in increased interest, dividend and other income earned in the year as compared to the previous year.

For the nine months ended September 30, 2009, EBITDA decreased by \$5.4 million compared to the same period in 2008. The decrease in EBITDA in the nine months ended September 30, 2009 is due to \$4.4 million in lower earnings from operations and \$1.6 million in increased administration expenses, partially offset by \$0.5 million in increased interest, dividend and other income earned in the year as compared to the previous year.

Reconciliation of adjusted net earnings/(loss) to net earnings/(loss)

Adjusted net earnings is a non-GAAP metric used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact and are viewed as not directly related to a company's operating performance. Net earnings/(loss) of Algonquin can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. Algonquin uses adjusted net earnings to assess the performance of Algonquin without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps as these are not reflective of the performance of the underlying business of Algonquin. Algonquin believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of Algonquin's businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

The following table is derived from and should be read in conjunction with the Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to adjusted net earnings and provides additional information related to the operating performance of Algonquin. Investors are

cautioned that this measure should not be construed as an alternative to consolidated net earnings in accordance with GAAP.

The following table shows the reconciliation of net earnings/(loss) to adjusted net earnings exclusive of these items:

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Net earnings	\$ 13,078	\$ (4,406)	\$ 32,623	\$ 2,057
Add:				
Loss (gain) on derivative financial instruments, net of tax	(6,148)	4,851	(12,621)	6,213
Loss (gain) on foreign exchange, net of tax	313	1,277	(1,003)	1,679
Adjusted net earnings	\$ 7,243	\$ 1,722	\$ 18,999	\$ 9,949
Adjusted net earnings per unit	\$ 0.09	\$ 0.02	\$ 0.24	\$ 0.13

The increase in adjusted net earnings in the three and nine months ended September 30, 2009 is due primarily to future income tax recoveries in the current year compared to future income tax expenses in the previous year. The primary reason for this recovery relates to the final determinations made for claiming discretionary deductions on the 2008 income tax returns, the impact of which is to reduce future income tax liabilities previously recorded.

Cash Available for Distribution

As a result of the Unit Exchange Offer described previously under Business Strategy and Recent Developments, on October 27, 2009 Algonquin became a wholly owned subsidiary of APUC, which corporation will be the continuing reporting issuer. Since corporations are not evaluated on the basis of cash available for distribution, this metric will not be reported upon in future management discussion and analysis reports.

The following tables are derived from and should be read in conjunction with the Consolidated Statement of Cash Flows. This supplementary disclosure is intended to more fully explain cash available for distribution and provides additional information related to the cash flows of Algonquin. Investors are cautioned that these measures should not be construed as an alternative to GAAP consolidated statement of cash flows.

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Cash provided by (used in) Operations	\$ 14,388	\$ 21,062	\$ 37,473	\$ 52,471
Changes in working capital	(2,540)	(3,953)	3,744	(273)
	11,848	17,109	41,217	52,198
Receipt of principal on notes receivable	170	79	351	232
Repayment of long term liabilities	(686)	(619)	(2,261)	(1,667)
Maintenance capital expenditures ¹	(1,068)	(1,373)	(2,511)	(3,107)
Other – non-recurring ²	1,594	-	1,393	(634)
Cash available for distribution	\$ 11,858	\$ 15,196	\$ 38,189	\$ 47,022

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
Add Back:				
Maintenance expenditures	1,068	1,373	2,511	3,107
Deduct:				
Net growth, maintenance and other expenditures	(3,303)	(17,224)	(10,249)	(45,047)
Cash available for distribution after growth and maintenance capital expenditures	\$ 9,623	\$ (655)	\$ 30,451	\$ 5,082
Distribution to Unitholders	\$ 4,775	\$ 18,019	\$ 14,328	\$ 52,981
Per Trust Unit				
Cash provided by Operations	\$ 0.18	\$ 0.27	\$ 0.47	\$ 0.68
Cash available for distribution	\$ 0.15	\$ 0.19	\$ 0.48	\$ 0.61
Cash available for distribution after net growth and maintenance expenditures	\$ 0.12	\$ (0.01)	\$ 0.38	\$ 0.07
Distributions to Unitholders	\$ 0.06	\$ 0.23	\$ 0.18	\$ 0.69
Distributions declared during the period	\$ 0.06	\$ 0.23	\$ 0.18	\$ 0.69

- Maintenance expenditures include plant and equipment expenditures capitalized in accordance with GAAP, which are of a replacement or regulatory nature or represent a major maintenance cost intended to maintain Algonquin's current operations and current level of distributable cash and refunds of developer contributions in Utility Services. The expenditures are amortized over the expected life of the respective asset and the amount amortized in the period is deducted in the calculation of cash available for distribution.
- Other includes various non-recurring adjustments including gain on sale of capital assets and any cash generated from operations that may not be available for immediate distribution to unitholders.

Distributions paid can be different from distributions declared during a period. Monthly distributions are declared by Algonquin for unitholders of record on the last business day of each month and are paid within 15 days following each month end. Prior to October 20, 2008, Algonquin's cash distributions to unitholders was \$0.92 per unit per annum, payable 45 days following each month end.

2009 Nine Month Cash Available for Distribution

The change in cash provided by operating activities after changes in working capital in the nine months ended September 30, 2009 is primarily due to realized losses from derivative financial instruments and decreased earnings from operating facilities, partially offset by decreased interest expense, as compared to the same period in 2008.

During the nine months ended September 30, 2009, Algonquin generated \$38.2 million (\$0.48 per trust unit) in cash available for distribution, as compared to \$47.0 million (\$0.61 per trust unit) for the same period in 2008. The decrease in cash available for distribution is mostly due to realized losses from derivative financial instruments, decreased earnings from operations and increased administrative costs as compared to the same period in 2008. These decreases were partially offset by decreased interest expense on variable interest rate debt and increased cash from working capital, as compared to the same period in 2008. Algonquin distributed \$14.3 million (\$0.18 per trust unit) during the nine months ended September 30, 2009, as compared to \$53.0 million (\$0.69 per trust unit) in the same period in 2008.

Algonquin's Payout Ratio was 37.5% during the nine months ended September 30, 2009 (2008 – 112.7%).

2009 Third Quarter Cash Available for Distribution

The change in cash provided by operating activities after changes in working capital in the quarter ended September 30, 2009 is primarily due to realized losses from derivative financial instruments and decreased earnings from operating facilities, partially offset by decreased interest expense, as compared to the same period in 2008.

During the quarter ended September 30, 2009, Algonquin generated \$11.9 million (\$0.15 per trust unit) in cash available for distribution, as compared to \$15.2 million, (\$0.19 per trust unit) for the same period in 2008. The decrease in cash available for distribution is mostly due to realized losses from derivative financial instruments, decreased earnings from operations and increased administrative costs as compared to the same period in 2008. These decreases were partially offset by decreased interest expense on variable interest rate debt and increased cash from working capital, as compared to the same period in 2008. Algonquin distributed \$4.8 million (\$0.06 per trust unit) during the quarter ended September 30, 2009, as compared to \$18.0 million (\$0.23 per trust unit) in the same period in 2008.

Algonquin's Payout Ratio was 40.3% during the quarter ended September 30, 2009 (2008 – 118.6%).

Excess (shortfall) of Cash Flows and Net Earnings Over Distributions Paid

The following chart presents excess or shortfall in cash flows from operating activities and net earnings over distributions paid for the three and nine months ended September 30, 2009 and for the years ended December 31, 2008 and 2007.

	Three and Nine months ended September 30, 2009		Year ended December 31	
			2008	2007
Cash flow from operating activities	\$ 14,388	\$ 37,473	\$ 66,874	\$ 40,427
Distributions paid during the period	(4,775)	(14,328)	(57,755)	(69,923)
Excess (shortfall) of cash flows from operating activities over cash distributions paid	\$ 9,613	\$ 23,145	\$ 9,119	\$ (29,496)
Net earnings (loss)	\$ 13,078	\$ 32,623	\$ (19,038)	\$ 24,763
Distributions paid during the period	(4,775)	(14,328)	(57,755)	(69,923)
Excess (shortfall) of net earnings over cash distributions paid	\$ 8,303	\$ 18,295	\$ (76,793)	\$ (45,160)

The excess of net earnings over cash distributions and of cash flows from operating activities over cash distributions has primarily been used to reduce long term debt and to invest in property plant and equipment.

Any previous shortfall of net earnings over cash distributions and of cash flows from operating activities over cash distributions have been funded through working capital management, issuance of additional trust units, convertible debenture offerings, cash on hand, or additional borrowings under Algonquin's revolving credit facility.

Algonquin considers the amount of cash generated by the business, cash required for Algonquin's growth initiatives, funds required to satisfy current or future obligations including taxes in determining sustainable, normalized monthly distributions of cash to its unitholders. In general, Algonquin does not take into account quarterly working capital fluctuations as these tend to be temporary in nature. Algonquin does not generally consider net income in setting the level of distributions as this is a non-cash calculation and does not reflect the

level of cash flow generated by Algonquin. In particular Algonquin has a relatively high level of depreciation and amortization expense and has significant volatility in income due to fluctuations from the quarterly mark to market valuations of its hedging instruments and interest rate swaps.

Summary of Property, Plant and Equipment Expenditures by Business Unit

	Three months ended September 30		Nine months ended September 30	
	2009	2008	2009	2008
POWER GENERATION & DEVELOPMENT				
Renewable Energy Division				
Maintenance expenditures	\$ 118	\$ 531	\$ 430	\$ 927
Growth and other expenditures	11	147	204	7,705
Total	\$ 129	\$ 678	\$ 634	\$ 8,632
Thermal Energy Division				
Maintenance expenditures	\$ 862	\$ 600	\$ 1,734	\$ 2,245
Growth and other expenditures	21	94	1,123	3,132
Total	\$ 883	\$ 694	\$ 2,857	\$ 5,377
UTILITY SERVICES BUSINESS UNIT				
Capital Investment in regulatory assets	\$ 2,283	\$ 15,817	\$ 6,651	\$ 30,927
Consolidated (includes Corporate)				
Maintenance expenditures	\$ 988	\$ 1,166	\$ 2,271	\$ 3,283
Capital investment in regulatory assets	2,283	15,817	6,651	30,927
Growth and other expenditures	32	241	1,327	10,837
Total	\$ 3,303	\$ 17,224	\$ 10,249	\$ 45,047

Algonquin capital expenditures in 2009 continue are lower than in 2008 due to a number of large capital projects that were completed in the previous year. The larger capital projects completed in 2008 were the BCI project, final capital associated with the Sanger re-powering project, larger growth related capital projects in the Utility Division, particularly at the LPSCo facility and the acquisition of the Campbellford hydroelectric facility.

Property, plant and equipment expenditures for the remainder of the 2009 fiscal year are anticipated to be approximately \$2.0 million, including approximately \$0.5 million related to ongoing requirements in Utility Services, \$1.0 million related to the Thermal division, and \$0.5 million related to the Renewable Energy division.

Algonquin anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital to finance its property, plant and equipment expenditures and other commitments. Algonquin also has the ability to finance these expenditures through its revolving credit facility as well as through advances from developers.

2009 Nine Month Expenditures

During the nine months ended September 30, 2009, Algonquin incurred growth and other property, plant and equipment expenditures of \$1.3 million, as compared to \$10.8 million during the comparable period in 2008. In addition, Utility Services invested \$6.7 million in property, plant and equipment during the nine months ended September 30, 2009, as compared to \$30.9 million during the comparable period in 2008.

During the nine months ended September 30, 2009, the Renewable Energy division's expenditures primarily relate to investments in the Great Falls and Franklin hydroelectric facilities. During the comparable period in 2008, the Renewable Energy division's expenditures primarily relate to the Campbellford acquisition, a 4,000 kilowatt hydroelectric generating facility located on the Trent-Severn Waterway approximately four kilometres north of Campbellford, Ontario, and projects at Great Falls and Dickson Dam.

During the nine months ended September 30, 2009, the Thermal Energy division's expenditures primarily relate to investments at the Dynafibres, Windsor Locks and BCI facility. In the comparable period, the expenditures primarily related to the completion of the Sanger re-powering project, investment in the BCI steam sales facility and investment at the EFW facility.

During the nine months ended September 30, 2009, the Utility Services' investment in property, plant and equipment primarily relate to completion and commissioning of projects initiated in 2008, additional well capacity and engineering work and an investment in property, net of approximately \$3.6 million of advances from developers. As previously noted, these investments have been included in the rate case applications currently underway. In the comparable period, the expenditures primarily related to investment in additional wells, engineering work regarding the waste-water treatment capacity and arsenic treatment at the LPSCo facility. The expenditures in the comparable period are included in the rate case applications which are currently in process.

2009 Third Quarter Expenditures

During the quarter ended September 30, 2009, Algonquin incurred growth and other property, plant and equipment expenditures of \$32, as compared to \$0.2 million during the comparable period in 2008. In addition, Utility Services incurred net investment in property, plant and equipment of \$2.3 million during the quarter ended September 30, 2009, as compared to \$15.8 million during the comparable period in 2008.

During the three months ended September 30, 2009, the Renewable Energy division's expenditures were not significant. During the comparable period in 2008, the Renewable Energy division's expenditures primarily relate to various projects at Great Falls and Dickson Dam.

During the three months ended September 30, 2009, the Thermal Energy division's expenditures primarily relate to investments in EFW, consistent with the comparable period.

During the three months ended September 30, 2009, Utility Services investment in property, plant and equipment primarily relates to an investment in property as noted in the nine month discussion above, net of approximately \$0.2 million of advances from developers. In the comparable period, the expenditures primarily related to investment in additional wells, engineering work regarding the waste-water treatment capacity and arsenic treatment at the LPSCo facility. As previously noted, these investments have been included in the rate case applications which are currently in process.

Liquidity and Capital Reserves

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to Algonquin under its senior banking credit facilities (the "Facilities"):

	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3
Committed bank credit facilities	\$ 176,700	\$ 189,050	\$ 192,750	\$ 192,750	\$ 192,750
Funds Drawn on credit facilities	(129,000)	(134,000)	(129,500)	(137,000)	(144,800)
Letters of Credit issued	(33,400)	(35,250)	(37,600)	(37,500)	(33,200)

	2009 Q3	2009 Q2	2009 Q1	2008 Q4	2008 Q3
Remaining available bank facilities	\$ 14,300	\$ 19,800	\$ 25,650	\$ 18,250	\$ 14,750
Cash on Hand	7,700	6,900	900	5,900	7,400
Total liquidity and capital reserves	\$ 22,000	\$ 26,700	\$ 26,550	\$ 24,150	\$ 22,150

As at and for the period ended September 30, 2009, Algonquin is in compliance with the covenants under its Facilities.

As at September 30, 2009, Algonquin had drawn \$129.0 million on its Facilities as compared to \$137.0 million as at December 31, 2008 and \$144.8 million as at September 30, 2008. In addition to amounts actually drawn, Algonquin also had \$33.4 million in outstanding letters of credit. At September 30, 2009, Algonquin had \$14.3 million of committed and available bank facilities and \$7.7 million of cash, resulting in \$22.0 million of total liquidity and capital reserves.

Contractual Obligations

Information concerning contractual obligations as of September 30, 2009 is shown below:

	Total	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations	\$ 281,319	\$ 3,057	\$ 201,799	\$ 3,342	\$ 73,121
Interest on long term debt obligations	\$ 121,989	18,483	25,593	20,119	57,794
Purchase obligations	\$ 28,681	28,681	-	-	-
Derivative financial instruments:					
Currency forward	\$ 2,633	833	1,848	(48)	-
Derivative financial instruments:					
Interest rate swap	\$ 9,853	5,939	2,865	799	250
Capital lease obligations	\$ 517	137	371	5	4
Other obligations	\$ 11,170	260	515	515	9,880
Total obligations	\$ 456,162	\$ 57,390	\$ 232,991	\$ 24,732	\$ 141,049

Long term obligations include regular payments related to long term debt and other obligations.

Unitholders' Equity and Convertible Debentures

As at September 30, 2009, Algonquin had 78,029,570 issued and outstanding trust units with a total of 79,580,200 trust units issued and outstanding on a fully diluted basis. Pursuant to the Unit Exchange offer, on October 27, 2009, the unitholders of Algonquin exchanged all issued and outstanding trust units for shares of APUC. Pursuant to the CD Exchange Offer, on October 27, 2009, holders of Series 1 debentures exchanged a portion of their debentures for an additional 6,607,027 shares of APUC.

Algonquin may issue an unlimited number of trust units. Each trust unit is transferable and represents an equal, undivided beneficial interest in any distribution from Algonquin and the net assets of Algonquin. All units are of the same class and with equal rights and privileges and are not subject to future calls or assessments. Each unit entitles the holder to one vote at all meetings of unitholders.

On August 1, 2008, Algonquin issued 3,507,143 trust units in exchange for cash and securities of approximately \$27.0 million or \$7.69 per unit. The unit issue was pursuant to an agreement entered into on September 27, 2008 between Algonquin, Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG"). Under

the agreement CJIG would acquire all of the issued and outstanding common shares of Highground, and Algonquin would issue 3,507,143 trust units, of which 3,065,183 trust units would be received by Highground shareholders as part of the agreement with the remaining trust units being retained by CJIG.

Pursuant to the takeover bid of AirSource Power Fund I LP (“Airsource”), on September 29, 2006 Algonquin issued trust units and a subsidiary issued trust units which are exchangeable into trust units of Algonquin at the holder’s option (the “Exchangeable Units”). Algonquin issued 44,608 trust units during the three months ended September 30, 2009 and 452,198 trust units during the nine months ended September 30, 2009 pursuant to the conversion of Exchangeable Units. As at September 30, 2009, there were 1,550,630 trust units of Algonquin remaining to be issued pursuant to the conversion of Exchangeable Units. Subsequent to September 30, 2009, 1,018,553 trust units of Algonquin were issued, pursuant to the conversion of Exchangeable Units. The compulsory acquisition provisions of the Exchangeable Units allow Algonquin to convert all the remaining Exchangeable Units once an additional 140,000 Exchangeable Units are exchanged.

In 2004, Algonquin issued 85,000 convertible unsecured debentures at a price of \$1,000 for each debenture maturing on July 31, 2011. The debentures bear interest at 6.65% per annum and are convertible into trust units of Algonquin at the option of the holder at a conversion price of \$10.65 per trust unit, being a ratio of approximately 93.9 trust units for each \$1,000 principal. During the period of July 31, 2009 until the debenture’s maturity, Algonquin can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional trust units. For the three and nine months ended September 30, 2009, no convertible debentures had been presented for conversion and there were 84,964 convertible debentures outstanding with a face value of \$84.96 million. Pursuant to the CD Exchange Offer all of these debentures have been exchanged for either new debentures of APUC or new common shares of APUC (see CD Exchange Offer described previously under Business Strategy and Recent Developments).

In November 2006, Algonquin issued 60,000 convertible unsecured debentures at a price of \$1,000 for each debenture maturing on November 30, 2016. The debentures bear interest at 6.2% per annum and are convertible into trust units of Algonquin at the option of the holder at a conversion price of \$11.00 per trust unit, being a ratio of approximately 90.9 trust units for each \$1,000 principal. The debentures may not be redeemed by Algonquin prior to November 30, 2010. During the period of November 30, 2010 until November 29, 2012, the debentures may be redeemed by Algonquin if the underlying trust unit price is equal to or exceeds a price of \$13.75 (125% of the conversion price of \$11.00). During the period of November 30, 2012 until the debenture’s maturity, Algonquin can redeem the debentures for 100% of the face value of debenture with cash, or for 105% of the face value of debenture with additional trust units. During the three months ended September 30, 2009, convertible debentures valued at \$33,000 were exchanged into 3,000 trust units and there were 59,967 convertible debentures outstanding with a face value of \$59.67 million. Pursuant to the CD Exchange Offer all of these debentures have been exchanged for new debentures of APUC (see CD Exchange Offer described previously under Business Strategy and Recent Developments).

Management of Capital Structure

Algonquin views its capital structure in terms of its debt levels, both at a project and an overall company level, in conjunction with its equity balances.

Algonquin’s objectives when managing capital are:

- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital.

- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets.
- To ensure generation of cash is sufficient to fund sustainable distributions to unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable distributions made to unitholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

Algonquin monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, Algonquin continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries as well as in the context of the change in taxation impacting Algonquin commencing in 2011.

Unitholders' Rights Plan

Algonquin has adopted a Unitholders' Rights Plan (the "Plan"). The Plan is designed to ensure the fair treatment of unitholders in any transaction involving a potential change of control of Algonquin and will provide the Board of Trustees and unitholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize unitholder value. The Toronto Stock Exchange (the "Exchange") has accepted notice for filing of the Plan and the Plan was approved by unitholders at Algonquin's annual and special meeting held on April 24, 2008 for a three year period thereafter. The Plan is similar to rights plans adopted by many other Canadian income trusts and corporations. Until the occurrence of certain specific events, the rights will trade with the trust units of Algonquin and be represented by certificates representing the Units. The rights become exercisable only when a person, including any party related to it or acting jointly with it, acquires or announces its intention to acquire twenty percent (20%) or more of the outstanding Units of Algonquin without complying with the Permitted Bid provisions of the Plan. Should a non-Permitted Bid be launched, each right would entitle each holder of Units (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Units of Algonquin at a fifty percent (50%) discount to the market price at the time.

It is not the intention of the Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Plan, a Permitted Bid is a bid made to all unitholders for all of their Units on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent (50%) of the outstanding Units, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Units but must extend the bid for a further ten days to allow all other unitholders to tender.

Related Party Transactions

The following related party transactions occurred during the quarter ended September 30, 2009:

- Algonquin is managed by APMI which provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. An entity owned by the majority of the shareholders of APMI is the general partner of Algonquin Airlink Limited Partnership and is the general partner of Algonquin Property LP which leases the corporate office to Algonquin. Green Wing Algonquin Power Development Inc ("GWAP") is an entity majority owned by APMI which provides construction services. Collectively these entities are called the Algonquin Power Group.
- For the nine months ended September 30, 2009, APMI was paid on a cost recovery basis for all costs incurred and charged \$639 (2008 - \$669).

- As part of the project to re-power the Sanger facility, Algonquin entered into an agreement with APMI to undertake certain construction management services on the project. APMI is entitled to a development supervision fee plus a contingency fee for its construction management role on the project. During the nine month period ending September 30, 2009, APMI was paid \$nil (2008 - \$23).
- Algonquin has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for the nine month period ending September 30, 2009 were \$249 (2008 - \$222).
- Algonquin utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. During the nine month period ending September 30, 2009, Algonquin incurred costs in connection with the use of the aircraft of \$307 (2008 - \$183) and amortization expense related to the advance against expense reimbursements of \$118 (2008 - \$74).
- In accordance with the construction services agreement related to the St. Leon facility, GWAP, a company controlled by APMI, was paid \$nil (2008 - \$134) during the nine month period ended September 30, 2009 for construction services.
- Pursuant to the St. Leon Limited Partnership Agreement, in 2006, St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of Airsource and the legal owner of the St. Leon facility, was required to issue 100 Class B units to GWAP. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing after June 17, 2008, two years after the date the facility achieved commercial operations pursuant to the PPA. Such income allocations and cash distributions shall be increased by 2.5% for each successive 5 year period, to a maximum of 10.0%. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The holders of the Class B units are entitled to cash distributions of \$368 during the nine months ended September 30, 2009 (2008 - \$131).
- On March 10, 2008, Algonquin advanced \$225 to the Trustees for purposes of enabling the Trustees to purchase additional Units of Algonquin. The loans are subject to promissory notes issued in favour of Algonquin which are payable upon demand, currently bear interest at 1% per annum, and are recorded as a reduction in Trust Units on the consolidated balance sheet. During the nine months ended September 30, 2009 principal repayments of \$15 were made (2008 - \$nil). On October 27, 2009 these loans were fully repaid.
- Pursuant to the Highground transaction that occurred on June 27, 2008 between Algonquin, Highground and CJIG, APMI was entitled to a fee of approximately \$240 which was recorded in 2008. This amount was paid in the second quarter of 2009.
- APMI is entitled to 50% of the cash flow above a 15% return on investment for the BCI project pursuant to its project management contract. During the nine months ended September 30, 2009 and 2008, no amounts were paid under this agreement. In 2008, APMI earned a construction supervision fee of \$100 in relation to the development of this project. As of September 30, 2009 this amount is accrued and included in accounts payable on the consolidated balance sheet.

Risk Management

Algonquin proactively manages its risk exposures in a prudent manner. Algonquin maintains adequate insurance on all of its facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also

initiated a number of programs and policies such as employee health and safety programs, environmental safety programs, and currency hedging policies to manage its risk exposures.

There are a number of risk factors relating to the business of Algonquin. Some of these risks include the dependence upon Algonquin businesses, regulatory climate and permits, U.S. versus Canadian dollar exchange rates, tax related matters, commodity prices, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that Algonquin may encounter. A further assessment of Algonquin's business risks is also set out in the 2008 Annual Information Form.

Mechanical and Operational Risks

Algonquin is entirely dependant upon the operations and assets of Algonquin businesses. Accordingly, distributions to unitholders are dependent upon the profitability of each of Algonquin's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. The water distribution networks of the water utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

These risks are mitigated through the diversification of Algonquin's operations, both operationally (Renewable Energy, Thermal Energy and Utility Services) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, Algonquin's existing long term PPAs minimize the risk of reductions in average energy pricing.

Regulatory Risk

Profitability of Algonquin businesses is in part dependant on regulatory climates in the jurisdictions in which it operates. In the case of some hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue.

The utility facilities are highly regulated and are subject to rate settings by state regulators. The operating companies are regulated utilities subject to the full regulation of the public utility commissions for the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The utilities use a historic test year subject to certain adjustments for known and measureable changes in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with the reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. These regulatory bodies have the authority to establish the allowed rate of return on approved rate base and also determine which investments are approved for inclusion in the rate base which in both cases can affect the profitability of the division. If the utilities are unable to obtain government approval of requested rate increases, or if rate increases are untimely or inadequate to cover capital investments and to recover expenses, profitability could be affected.

Federal, state and local environmental laws and regulations impose substantial compliance requirements on water and wastewater utility operations. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Water and wastewater utilities could be subject to condemnation or other methods of taking by government entities under certain conditions. While any taking by government entities would require compensation be paid to Algonquin, and while Algonquin believes it would receive fair market value for any assets that are taken, there is no assurance that the value received for assets taken will be in excess of book value.

Algonquin regularly works with these authorities to manage the affairs of the business.

Asset Retirement Obligations

Algonquin completes periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, Algonquin considers the contractual requirements outlined in its operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations. Based on its assessments, Algonquin does not have any significant retirement obligation liabilities and has not recorded any liability in its financial statements.

Generally, Algonquin's hydroelectric facilities are subject to some form of a water use agreement. The terms of these agreements vary by facility as they are agreements made with the local government body that regulates electrical energy generators and can extend over many years. Certain of the agreements contain clauses which allow the regulating body the option to require Algonquin to decommission the facility upon the expiry or termination of the agreements. Other facilities have no specific obligations other than to maintain the facility in good working order. Algonquin has options in many of its existing water use agreements to renew or extend the agreements and anticipates being in a position to extend the majority of its agreements and continue to operate its facilities. Based on historical general practice within the regions in which Algonquin has facilities, Algonquin has assessed the probability of being required to decommission a facility upon the expiry of a water use agreement to be remote. As such, the any potential asset retirement obligation expense has been assessed as insignificant as the obligation would be incurred well into the future and there is a remote likelihood of being required to decommission a facility.

The Renewable Energy division's St. Leon facility does not own the property on which its turbines are located. In 2004, St. Leon entered into long term right of way agreements with land owners which allowed it to construct and maintain the wind turbines used by the facility on their property. These agreements are for minimum terms of 40 years and, upon expiry or termination, provide the land owners with title to the equipment if it is not decommissioned by Algonquin at its option. While Algonquin anticipates being in a position to renew or extend the existing PPA in 2025, in the event that Algonquin is unable to renew or extend the agreement, or identify another purchaser of the energy, Algonquin may choose to decommission the facility. Algonquin has assessed there to be a remote likelihood of incurring any cost to decommission the wind farm.

The Thermal Energy division's EFW facility owns the property on which its facility operates. EFW's current waste incineration agreement expires in 2012 with two five year options to extend. While Algonquin anticipates being in a position to renew or extend the existing contract in 2012, in the event that Algonquin is unable to renew or extend the agreement, Algonquin may choose to close the facility but has no legal obligation to remove the assets. Under the terms of the contract, the responsibility for removal of the bulk of any hazardous material generated in the operation of the facility remains with EFW's primary customer. As such, the potential expense to bring the facility in line with current environmental standards in the event

it is eventually closed has been assessed as insignificant based on the quantification of costs to remediate the facility, expectation that the existing contract can be extended or renewed and that the potential timing of such an event, although unlikely, would be well in the future.

The Utility Services business unit's facilities operate under agreements with a state or municipal regulator to provide the sole water distribution and/or wastewater treatment services in its area of operations, as set out in the agreements. In general, these facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Utility Services has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging wastewater treatment facilities and expenses associated with providing new sources of water can generally be included in the facility's rate base and thus the facility is allowed to earn a return on its investment.

Environmental Risks

Algonquin faces a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies. Algonquin has assessed the likelihood of these risks becoming a contingent environmental liability as remote; therefore Algonquin has not recorded any contingent liabilities on its financial statements.

To manage these risks responsibly, Algonquin has Environmental and Compliance departments within the different operating units of the businesses which are responsible for monitoring all of Algonquin's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required. The departments comprise of 7.0 full time equivalent positions based out of head office and have an annual budget of approximately \$1.0 million, which includes wages, travel and other costs. Facility specific permitting and compliance expenses are direct operating expenses of each facility and are excluded from these expenses.

Algonquin's procedures in place to prevent and minimize any impact of possible oil spills and soil contamination meet generally accepted industry practices. Algonquin's field personnel perform inspections of oil and chemical storage areas on a minimum of a quarterly basis. Algonquin has 24 hour, 365 day emergency response and spill procedures in place in the event there is an oil or chemical spill.

The Renewable Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a hydroelectric facility include possible dam failure which results in upstream or downstream flooding; equipment failure which result in oil or other lubricants being spilled into the waterway. In addition, the operation of a hydroelectric facility may cause the water in the associated waterway to flow faster, or slower, which could result in water flow issues which impact fish population, water quality and potential increases in soil erosion around a dam facility. In order to monitor and mitigate these risks, Algonquin completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility. Federal regulators in the U.S. inspect certain hydroelectric facilities on an annual basis and complete an environmental inspection every 3-5 years.

The primary environmental risks associated with the operation of a wind farm include potential harm to the

local and migratory bird population, harm to the local bat population as well as concerns over noise levels and visual 'harm' to the scenic environment around the wind farm. As part of the Federal and Provincial approval of the St. Leon wind project, certain pre-construction and post construction monitoring studies were required. No significant issues were identified as a result of these studies. In order to monitor and mitigate these risks, Algonquin completes facility inspections at minimum on an annual basis and ensures its facilities are in compliance with the appropriate regulatory requirements for the specific facility.

The Thermal Energy division faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a cogeneration facility include potential air quality and emissions issues, soil contamination resulting from oil spills and issues around the storage and handling of chemicals used in normal operations. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Algonquin maintains continuous emissions monitoring systems, performs regular stack testing and tests the calibration of monitoring. The primary environmental risks associated with the operation of an incineration facility include potential air quality, odour and emissions issues, soil contamination resulting from oil or other chemical spills and issues around the storage and handling of municipal solid waste. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Algonquin maintains continuous emissions monitoring systems, performs annual stack testing and completes an annual technical evaluation of ash composition.

The Utility Services business unit faces a number of environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of a wastewater treatment facility include potential air quality and odour management issues, wastewater spills and surface and ground water contamination. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Algonquin maintains an ongoing sampling and testing programs as required in its operational jurisdiction, including annual field investigations by management. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the wastewater collection system and at the wastewater treatment plants that it operates.

The primary environmental risks associated with the operation of a water distribution facility include risk of groundwater contamination by contaminants such as bacterial, synthetic, organic and inorganic pollutants, consumption and availability of groundwater and ensuring water quality continues to meet and exceed Environmental Protection Agency ("EPA") and state standards. In order to monitor and mitigate these risks, and to remain within the regulatory requirements appropriate for the specific facility, Algonquin maintains a regular sampling and testing program as required in its operational jurisdiction. It also has a preventative maintenance program to reduce the risk of leaks and other mechanical failures within the water distribution systems that it operates.

Federal drinking water legislation in the United States requires all drinking water systems to meet new standards respecting levels of naturally occurring arsenic in drinking water. Pursuant to the requirements of the drinking water legislation, an additional arsenic treatment system has been placed online at one of LPSCo's reservoir well sites to ensure continued full compliance with the regulatory requirements. The costs of complying with the new standards form part of a facility's rate base for rate case purposes.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the

water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings

Specific Environmental Risks

Greenhouse Gas Initiatives:

Several Northeastern US States have formed a coordination group to develop a multi state green house gas mitigation action plan. This group, the Regional Greenhouse Gas Initiative (“RGGI”), has received backing from several states where Algonquin operates facilities including Connecticut and New Jersey. RGGI drafted a model cap and trade legislation that has been endorsed by all of the states involved in the initiative. The cap and trade program will be implemented to regulate CO₂ emissions from large electrical generation facilities, including the Windsor Locks facility. The RGGI regulation to implement a greenhouse gas cap and trade program was passed in Connecticut in late August 2008.

The Windsor Locks facility is the only Algonquin site that is currently affected by the RGGI regulations. As such Algonquin will be required to purchase approximately 250,000 tons of CO₂ allowances per year, equivalent to the total annual CO₂ emissions from the Windsor Locks facility for the 2009 to 2012 fiscal years. Algonquin is entitled to apply for allowances and/or purchase allowances at a base price of \$2.00 per tonne from the state of Connecticut. Algonquin submitted an application on October 31, 2008 for allowances under the available programs. For 2009, Algonquin has currently estimated the cost of compliance with the RGGI requirements for the Windsor Locks facility to be between \$0.4 and \$0.5 million.

Seven U.S. States (including Arizona and California) and four Canadian provinces (including Manitoba, Ontario and Quebec) have formed a group called the Western Climate Initiative (“WCI”). This group recently released details of its Regional Cap-and-Trade Program, which is scheduled to start on January 1, 2012. Each member state/province is now responsible for developing the draft design of the Regional Cap-and-Trade Program and taking the necessary steps to implement the Program within its jurisdiction. Algonquin owns and operates the Sanger facility in California and the EFW facility in Ontario and holds investments in two others in Ontario which could be impacted by this program. As this process has just begun, it is too early to determine the potential financial impact on Algonquin and means available to mitigate this financial impact, if any.

The Carbon Disclosure Project (“CDP”) is an independent non-profit organization that represents institutional investors managing over \$57.0 trillion of assets. The CDP is specifically working to encourage companies world wide to quantify and disclose their greenhouse gas emissions and to outline what actions the companies are taking to address climate change risk, both from potential physical impacts but also from regulatory changes that may result in an effort to address climate change.

Algonquin submitted a baseline greenhouse gas emissions inventory to the CDP at the end of June 2008. The emissions data includes both direct emissions from our processes as well as indirect emissions from purchased power. The emissions inventory has been developed based on guidance from the Greenhouse Gas Protocol. This submission will allow comparisons with other firms to be made, and will also be useful as a baseline for addressing climate change regulations.

Renewable Energy Division:

As a result of certain legislation passed in Quebec (Bill C93), Algonquin is undertaking technical assessments of its hydroelectric facility dams owned or leased within the Province of Quebec. This is discussed in greater detail within the analysis of results in the Renewable Energy Division.

The province of Ontario is considering enacting new legislation similar to Bill C93 in Quebec. Algonquin operates four hydroelectric facilities in Ontario. While it is too early to assess the costs of compliance, it is possible that modifications to certain dam structures may be required in order to be compliant with any new regulations should they come into effect. Any capital costs associated with the anticipated modifications are expected to be significantly lower than the expected capital costs related to the Quebec facilities, as there are fewer facilities in Ontario and they are of newer construction.

Utility Services:

Algonquin owns and operates the LPSCo facility, a water distribution and waste-water treatment utility servicing the City of Litchfield Park, and parts of the City of Goodyear, the City of Avondale and the County of Maricopa, Arizona, where groundwater pollutants originally caused by a former aerospace manufacturing plant in the nearby city of Goodyear are progressing toward three of the twelve wells that provide water to the LPSCo service area. The EPA began monitoring these groundwater pollutants in 1981 and has been tracking the gradual underground movement since. In addition to actively participating in EPA monthly technical meetings in regards to this monitoring program, LPSCo closely monitors its wells for these groundwater pollutants through the sampling and testing of water from wells that are potentially at risk of contamination.

To date there have not been any detectable levels of the pollutants in the water from wells used by the utility. EPA's monitoring and control efforts have not indicated that the concentrations are being reduced or fully captured. Additional remedial efforts by the EPA to stop advancement and reduce contamination concentrations are underway. In the event that any of the wells which are most immediately at risk exceed permitted contaminant levels, LPSCo would undertake the appropriate actions which may include removing the well at risk from the water distribution system of the utility. In this event, there would remain sufficient production and reservoir capacity within the balance of the water distribution system to adequately service the needs of all of the customers of the utility. In addition LPSCo has identified alternate sites where replacement wells can be established to replace this lost capacity. The cost of establishing a new well is estimated to be between \$1.5 million and \$3.0 million depending on the location, depth and other factors. The cost of commissioning a well forms part of the rate base for the utility. Other factors that can impact the cost of a well include, but are not limited to, any requirement to construct wellhead treatment for pollutants, volume of water available at the new site, and acquisition of land and groundwater rights. Algonquin does not believe it is exposed to a material liability and has not recorded a contingent environmental liability on its financial statements.

Algonquin's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at September 30, 2009.

Seasonal fluctuations and hydrology

The hydroelectric operations of Algonquin are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized. For Algonquin's water utilities, demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water

use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Wind resource

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

Foreign currency risk

Currency fluctuations may affect the cash flows Algonquin would realize from its operations, as certain Algonquin businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such Algonquin businesses also incur costs in U.S. dollars. At Algonquin's current exchange rate, approximately 45% of EBITDA and 60% of cash is generated in U.S. dollars. Algonquin estimates that, on an unhedged basis, a \$0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in increased reported revenue from U.S. operations of approximately \$11.3 million and increased reported expenses from U.S. operations of approximately \$7.6 million or a net impact of \$3.7 million (\$0.05 per trust unit) on an annual basis.

Algonquin previously managed this risk primarily through the use of forward contracts as it required U.S. dollar cash inflows to meet Canadian dollar cash outflows. As a result of the current business strategy and lower payout ratio, Algonquin has determined that its prior practice of hedging 100% of its U.S. currency exposure is no longer appropriate and is taking steps to eliminate its existing forward currency contract program and subsequent to September 30, 2009, Algonquin terminated forward contracts of \$39.4 million for net proceeds of \$0.1 million. Algonquin's policy is not to utilize derivative financial instruments for trading or speculative purposes.

During the quarter ended September 30, 2009 Algonquin realized a \$0.1 million gain on forward contracts settled during the period. For the nine months ended September 30, 2009 Algonquin realized a \$0.4 million loss on forward contracts settled during the period.

The following chart sets out the amount of foreign exchange forward contracts outstanding as at October 10, 2009, hedge proceeds and average hedged rates over the term of the contracts:

	Total	2009	2010	2011	2012	2013
Total U.S. \$ Hedged	\$ 50,997	\$ 3,717	\$ 7,520	\$ 26,450	\$ 12,560	\$ 750
Total Can. \$ Proceeds	\$ 52,278	3,957	7,861	26,793	12,864	803
Average Hedged Rate	\$ 1.025	\$ 1.065	\$ 1.045	\$ 1.013	\$ 1.024	\$ 1.070
Unrealized Gain (loss)	\$ (2,212)	(22)	(184)	(1,450)	(553)	(3)
Impact of a \$0.10 move in exchange rates	\$ 5,100	\$ 372	\$ 752	\$ 2,645	\$ 1,256	\$ 75

Based on the fair value of the forward contract using the exchange rates as at September 30, 2009, the exercise of these forward contracts will result in the use of cash of \$22 in the remainder of fiscal 2009, the use of cash of \$0.2 million in fiscal 2010 and result in the use of cash of \$2.0 million for the remainder of the hedged period beyond 2010. Assuming a decrease in the strength of the US dollar relative to the Canadian dollar of

\$0.10 at September 30, 2009, with a corresponding increase in the forward yield curve, the fair value of the outstanding forward exchange contracts would increase by \$5.1 million, reducing the expected use of cash by \$0.4 million during the remainder of fiscal 2009, \$0.8 million in fiscal 2010, and \$4.0 million for the remainder of the hedged period beyond 2010.

Market price risk

The majority of Algonquin's facilities are subject to long term PPAs. However, certain of Algonquin's hydroelectric facilities in the New England and New York regions sell energy at current spot market rates. In this regard, each \$10.00 change in the market prices per MW-hr would result in a change in revenue of \$1.0 million on an annualized basis.

Credit/Counterparty risk

Algonquin is subject to credit risk through its trade receivables. Algonquin does not believe this risk to be significant as over 90 % of Renewable Energy division's revenue, 80% of Thermal Energy division's revenue, and over 70% of total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The remaining revenue is primarily earned by the Utility Services business unit. In this regard, the credit risk related to Utility Services accounts receivable balances of US \$3.6 million is spread over approximately 70,000 customers, resulting in an average outstanding balance of approximately \$50 per customer. Algonquin has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

Interest rate risk

Algonquin has a number of project specific and other debt facilities that are subject to a variable interest rate. These facilities and the sensitivity to changes in the variable interest rates charged are discussed below:

- Algonquin's senior debt facility had a balance of \$129.0 million as at September 30, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by \$1.3 million annually. Algonquin has fixed for floating interest rate swaps in an amount of \$100.0 million until December 31, 2010, and fixed the interest expense on \$100.0 million of borrowings at approximately 3.46% for 2009, and 4.125% for 2010. This reduces volatility in the interest expense on this debt. The financial impact of any changes in interest rates are partially offset between the change in interest expense and the change in value of the interest rate swap. At September 30, 2009, the mark to market value of the interest rate swap was a net \$3.9 million liability (September 30, 2008 – net \$1.2 million liability).
- Algonquin's project debt at the St. Leon facility had a balance of \$70.9 million as at September 30, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by \$0.7 million annually. Although the underlying debt with the project lenders carries variable rate of interest tied to the Canadian bank's prime rate, Algonquin has entered into a fixed for floating interest rate swap on this project specific debt until September 2015 which mirrors the underlying debt's interest and principal repayment schedule. This minimizes volatility in the interest expense on this debt. The financial impact of interest rate changes are effectively offset between the change in interest expense and the change in value of the interest rate swap. Algonquin has effectively fixed its interest expense on its senior debt facility at 5.47%. At September 30, 2009, the mark to market value of the interest rate swap was a net liability of \$5.9 million (September 30, 2008 – liability of \$2.6 million).

- Algonquin's project debt at its Sanger cogeneration facility has a balance of U.S. \$19.2 million as at September 30, 2009. Assuming the current level of borrowings over an annual basis, a 1% change in the variable rate charged would impact interest expense by \$0.2 million annually.

Liquidity risk

Liquidity risk is the risk that Algonquin will not be able to meet its financial obligations as they fall due. Algonquin's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due.

On October 20, 2008, in order to strengthen Algonquin's financial position and support its growth initiatives, Algonquin reduced the cash distributions payable to Algonquin's unitholders to \$0.24 per unit per annum commencing with the October 2008 distribution.

As at September 30, 2009, Algonquin had cash on hand of \$7.7 million and \$14.3 million available to be drawn on committed credit facilities from its bank syndicate. See the Liquidity and Capital Reserves section for a more detailed discussion and chart of the funds available to Algonquin under its credit facilities.

Algonquin's Facilities and project specific debt total approximately \$278.0 million. In the event that Algonquin was required to replace these Facilities with borrowings having less favourable terms or higher interest rates, the level of cash generated for distribution may be negatively impacted. Algonquin attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash available for distribution generated from several of Algonquin's operating facilities are subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regards to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and Algonquin losing its investment in such operating facility. Algonquin actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Commodity price risk

Algonquin's exposure to commodity prices is primarily limited to exposure to natural gas price risk. In this regard, a discussion of this risk is set out as follows:

Algonquin's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a \$1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately \$1.1 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of \$1.2 million or a net increase in operating profits of approximately \$0.1 million.

Algonquin's Windsor Locks facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a \$1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately \$2.8 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of \$3.3 million or a net increase in operating profits of approximately \$0.6 million.

Algonquin's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a \$1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in expenses of approximately \$0.3 million on an annual basis. However, because the facility's energy price is linked to the price of natural gas, this increase would result in a corresponding increase in revenue of \$0.4 million or a net increase in operating profits of approximately \$0.1 million.

Litigation risks and other contingencies

Algonquin and certain of its subsidiaries are involved in various litigations, claims and other legal proceedings that arise from time to time in the ordinary course of business. Any accruals for contingencies related to these items are recorded in the financial statements at the time it is concluded that a material financial loss is likely and the related liability is estimable. Anticipated recoveries under existing insurance policies are recorded when reasonably assured of recovery.

As reported in previous public filings of Algonquin, Trafalgar Power, Inc. and Christine Falls Power Corporation (collectively, "Trafalgar") commenced an action in 1999 in U.S. District Court against Algonquin, APMI and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to Algonquin and in connection with the foreclosure on the security for the Note which includes interests in Trafalgar entities that own hydroelectric generating facilities in New York. In 2001, Trafalgar and other entities also filed in bankruptcy court for Chapter 11 reorganization and filed a multi-count adversary complaint, some of which was then transferred to the district court action. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the B Note, that Algonquin was therefore the holder and owner of the B Note, and that all other claims by Trafalgar with respect to the transfer of the Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court were dismissed by summary judgement. On November 21, 2008, Trafalgar requested that the summary judgement be vacated based on alleged new evidence. The new evidence has, in the view of Algonquin, been falsified, and Algonquin has vigorously contested the request and has also taken further investigative steps in relation to the falsification. The motion was submitted for decision by the Court on January 9, 2009 and the motion was denied on September 25, 2009. The Court indicated that a report on the new evidence lacks a foundation and is not admissible. On October 22, Trafalgar filed an appeal from the November 6, 2008 summary judgement to the United States Court of Appeals for the Second Circuit.

There is also an action (the "Civil Action") commenced by Trafalgar pending against U.S. Bank National Association ("U.S. Bank"), the successor to State Street Bank, the indenture trustee. U.S. Bank filed a motion to dismiss the action, in response to which the Court has dismissed five of the eight counts asserted. On July 6, 2009, U.S. Bank filed a third party complaint against Algonquin claiming indemnity from Algonquin for its costs in the bankruptcy action, the district court action as well as the Civil Action. US Bank filed for voluntary dismissal of the complaint on October 8, 2009 without prejudice and agreed to forbear on re-filing until certain events occur. It is possible that a loss may result, but the timing of any such loss is uncertain. The amount of the loss for past legal fees cannot be determined at this time, but in any event is not likely to exceed \$0.5 million. The extent of the legal fees that U.S. Bank may incur in the future, and the amount, if any, that Algonquin may be liable for, cannot be determined at this time. Similarly, Algonquin's possible liability to U.S. Bank under theories of indemnity cannot be determined at this time.

Although APMI paid one half of the external legal fees incurred up to July 1, 2002 with respect to this dispute, Algonquin is funding the litigation. In the event of a recovery by Algonquin of all or part of the funds, Algonquin and APMI will divide such amounts in proportion to the amount of legal fees funded, after reimbursement of expenses.

On December 19, 1996, the Attorney General of Québec ("Québec AG") filed suit in Québec Superior Court against Algonquin Développement Côte Ste-Catherine Inc. (Développement Hydromega), a predecessor company to an Algonquin subsidiary. The Québec AG at trial claimed \$5.4 million for amounts that the

Algonquin entities have been paying to the federal authority under its water lease with the authority. The Algonquin entities brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009. The Côte Ste-Catherine Facility currently pays water lease dues to the federal government, but if the Québec AG is successful in any appeal, an adjustment and/or increase of such amounts is possible.

Obligations to serve

Algonquin's utility facilities may be located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, Algonquin may be required to access capital markets or obtain additional borrowings to finance these future construction obligations.

Changes to income tax laws

Changes to income tax laws and the current tax treatment of mutual fund trusts could negatively impact Algonquin. Although Algonquin is of the view that it currently qualifies under current legislation as a mutual fund trust, there can be no assurance that the legislation will not be changed in the future or that Canada Revenue Agency ("**CRA**") will agree with this position. If Algonquin ceases to qualify as a mutual fund trust, the return to Unitholders may be adversely affected.

Algonquin will be deemed not to be a mutual fund trust if it can be reasonably considered that Algonquin, having regard to all the circumstances, was established or maintained primarily for the benefit of non-resident persons. On September 16, 2004, the Minister of Finance released certain proposals (the "**September 2004 Proposals**") that a trust, such as Algonquin, would lose its status as a mutual fund trust under the Tax Act if, at any time, the aggregate fair market value of all of its issued and outstanding units held by one or more non-resident persons and/or by partnerships which are not Canadian partnerships under the Tax Act, is more than 50% of the aggregate fair market value of all issued and outstanding units of the trust, unless no more than 10% (based on fair market value) of the trust's property at any time is taxable Canadian property and certain other types of specified property. These proposals did not provide any means of rectifying the loss of mutual fund trust status. On December 6, 2004, the Minister of Finance suspended implementation of these proposals pending further consultation with the private sector. Bill C-52, which received Royal Assent on June 22, 2007, amended the Tax Act to provide that a trust will be deemed not to be a mutual fund trust after any time when it can reasonably be considered that the trust was established or maintained primarily for the benefit of non-resident persons, unless at that time all or substantially all of its property is property other than taxable Canadian property. It is not clear whether this amendment supersedes the September 2004 Proposals.

On June 22, 2007, Bill C-52 was enacted, which included legislation to impose a tax on certain income distributed to Unitholders by certain publicly traded income trusts and partnerships (the "**SIFT Rules**"). The SIFT Rules apply to "specified investment flow-throughs" ("**SIFTS**") which includes trusts resident in Canada whose units are listed or traded on a stock exchange or other public market if the trust holds one or more "non-portfolio properties".

Pursuant to SIFT Rules, Algonquin will constitute a SIFT trust. Management has concluded that Algonquin would have been a SIFT trust on October 31, 2006 had the SIFT Rules been in force on that date. Therefore, pursuant to the applicable grandfathering rules therein, the SIFT Rules will not apply to Algonquin until the earlier of its first taxation year that ends in 2011 or its transition year which includes the first day after December 15, 2006 on which Algonquin exceeds normal growth guidelines (the "Guidelines") issued by the

Department of Finance on December 15, 2006, revised on December 5, 2008 and as may be further amended from time to time. Provided Algonquin does not exceed normal growth as determined by the Guidelines, the SIFT Rules will apply to Algonquin starting with its 2011 taxation year. However, no assurances can be given that Algonquin will not become subject to the SIFT Rules prior to 2011 and loss of its grandfathered status could have a material and adverse impact on the value of the Trust Units.

Certain amendments to the SIFT Rules which were included in Bill C-10 received Royal Assent on March 12, 2009. These amendments include changes to SIFT definition to exclude trusts and partnerships whose equity is not publicly traded, and is wholly owned by a SIFT, a real estate investment trust, a taxable Canadian corporation, another entity meeting this test, or any combination of these types of entities. Algonquin has a subsidiary partnership that may not meet this ownership requirement and therefore this entity may be subject to SIFT tax commencing in 2011, or earlier if it exceeds its normal growth guidelines.

Once the SIFT Rules apply, Algonquin will be subject to tax in respect of non-portfolio earnings which it distributes at a rate intended to approximate the general corporate tax rate. Any non-portfolio earnings distributed by Algonquin will be taxable to the Unitholder as if the distribution were a taxable dividend from a taxable Canadian corporation and will be deemed to be an “eligible dividend” eligible for the enhanced gross-up and tax credit. Dividend income and income received directly from foreign sources is excluded from the definition of non-portfolio earnings and therefore will not be taxable in Algonquin.

When the SIFT Rules apply to Algonquin, the imposition of tax under the SIFT Rules could materially reduce Algonquin’s after tax earnings.

Although Algonquin is of the view that all expenses being claimed by Algonquin are reasonable and that the cost amount of Algonquin’s depreciable properties have been correctly determined, there can be no assurance that CRA or the Internal Revenue Service will agree. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to Unitholders.

On October 31, 2003, the Department of Finance released, for public consultation, draft proposed amendments (the “October 2003 Proposals”) to the Tax Act that would require, for taxation years commencing after 2004, that there be a reasonable expectation of profit from a business or property for a taxpayer to realize a loss from such business or property, and that makes it clear that a profit for this purpose does not include capital gains. On February 23, 2005, the Minister of Finance announced that the Department of Finance is developing an alternative to the October 2003 Proposals which will be released for comment in the near future. Such alternative proposal has not yet been released. The October 2003 Proposals could affect Algonquin’s ability to deduct its expenses, although Algonquin does not expect to be adversely affected by the October 2003 Proposals.

Critical Accounting Estimates

Algonquin prepared its Consolidated Financial Statements in accordance with GAAP. An understanding of Algonquin’s accounting policies is necessary for a complete analysis of results, financial position, liquidity and trends. Refer to Note 1 to the Consolidated Financial Statements for additional information on accounting principles. The Consolidated Financial Statements are presented in Canadian dollars rounded to the nearest thousand, except per unit amounts and except where otherwise noted.

Financial statements prepared in accordance with GAAP require management to make estimates and assumptions relating to reported amounts of revenue and expenses, reported amounts of assets and liabilities and disclosure of contingent assets and liabilities. Algonquin regularly evaluates the assumptions and estimates that are used

in the preparation of Algonquin's Consolidated Financial Statements. Estimates and assumptions used by management are based on past experience and other factors deemed reasonable in the circumstances. Since these estimates and assumptions involve varying degrees of judgment and uncertainty, the amounts reported in the financial statements could in the future prove to be inaccurate.

Algonquin recognizes revenue derived from energy sales at the time energy is delivered. Utility Services revenue is recognized when processed and delivered to customers. Revenue from waste disposal is recognized on an actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts are recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected is deferred.

Algonquin records as other liabilities amounts received by Utility Services which relate to advances from developers for water distribution and water reclamation main extensions received. These advances usually carry repayment terms based on the revenue generated by the development in question ranging over a specified period of time. At the end of the payment term, the unpaid portion of the advance converts to contribution in aid of construction and is not required to be repaid to the developer. The amount recorded as other liabilities is based on Algonquin's expected repayments as determined by historical experience and industry practice.

Estimates are also made related to the useful life of long-lived assets. These estimates are used to determine amortization expense. Estimates of an asset's useful life are based on past experience with similar assets taking into account technological or other changes. If these estimates prove to be inaccurate, management may have to shorten the anticipated useful life of the assets recorded in the financial statements resulting in higher amortization expense in future periods or possibly an impairment charge to reflect the write-down in the value of the asset.

Algonquin also regularly assesses whether there has been an impairment to long term investments, notes receivable, capital and intangible assets, and recoverability of future tax assets based on circumstances that may indicate Algonquin will not be able to recover the assets entire carrying value. Should impairment be deemed to have occurred, Algonquin would reduce the carrying value of that asset in the financial statements and deduct this amount from earnings. Algonquin cannot predict future events that could create impairment, or how future events might affect the carrying value of the assets' values reported in the financial statements.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended September 30, 2009.

Millions of dollars (except per trust unit amounts)	4th Quarter 2008	1st Quarter 2009	2nd Quarter 2009	3rd Quarter 2009
Revenue	\$ 56.5	\$ 52.2	\$ 46.5	\$ 45.1
Net earnings /(loss)	(21.1)	4.2	15.3	13.1
Net earnings / (loss) per trust unit	(0.27)	0.05	0.20	0.17
Total Assets	975.9	974.2	952.4	925.7
Long term debt*	462.9	457.6	456.2	445.4
Distribution per trust unit	0.06	0.06	0.06	0.06

	4th Quarter 2007	1st Quarter 2008	2nd Quarter 2008	3rd Quarter 2008
Revenue	\$ 44.3	\$ 48.0	\$ 54.2	\$ 55.1
Net earnings from continuing operations	7.5	(1.6)	8.0	(4.4)
Net earnings	7.6	(1.6)	8.0	(4.4)
Net earnings from continuing operations per trust unit	0.12	(0.02)	0.10	(0.06)
Net earnings per trust unit	0.10	(0.02)	0.10	(0.06)
Total Assets	953.0	948.5	950.0	962.7
Long term debt*	445.1	460.6	469.6	460.9
Distribution per trust unit	0.23	0.23	0.23	0.23

* Long term debt includes long term liabilities, convertible debentures and other long term obligations

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between \$44.3 million and \$56.5 million over the prior two year period. A number of factors impact quarterly results including seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. There are two additional significant factors impacting revenues year over year. The fluctuation in the strength of the Canadian dollar has resulted in significant changes in reported revenue from U.S. operations, as well as realized gains on financial instruments were recorded as revenue in the comparable quarters of 2007.

Quarterly net earnings have fluctuated between net earnings of \$15.3 million and a net loss of \$21.1 million over the prior two year period. Recent earnings have been significantly impacted by non-cash factors such as future tax expense due to the enactment of Bill C-52 and gains and losses on financial instruments due to Algonquin's adoption of Section 3855 and the discontinuation of hedge accounting under Section 3865.

Accounting Treatment for the Unit Exchange and CD Exchange Offers

Anticipated Accounting Treatment of the Unit Exchange Offer

The Unit Exchange transaction has resulted in the Unitholders of Algonquin becoming shareholders of the APUC and is required to be accounted for as a change in business form using the continuity of interests method. For the purposes of accounting, APUC is required to be accounted for as though it were a continuation of Algonquin but with its capital reflecting the exchange of APUC Shares for Trust Units and its future tax asset recognizing the tax attributes of Hydrogenics Corporation. Under this method, the transfer will be accounted for using the carrying amounts reflected in the consolidated financial statements of Algonquin. Comparative figures presented in the consolidated financial statements of APUC will include all amounts previously reported by Algonquin. The acquisition of tax attributes will be accounted for as future income tax assets recognized to the extent expected to be realized with any excess of the carrying amount recorded over the consideration paid to New Hydrogenics reflected as a deferred credit to be recognized in income as an income tax expense recovery as the future income tax assets are realized.

As a result of the Unit Exchange Offer, APUC paid New Hydrogenics approximately \$10,813. APUC retains tax attributes of approximately \$192,000 which is in addition to the existing tax attributes of Algonquin. APUC will recognize a future income tax asset of approximately \$62.2 million and a deferred credit in relation to this asset of approximately \$50.4 million. The estimated amount of the future income tax asset, deferred credit and the

amount of cash consideration are subject to final closing adjustments. For accounting purposes the deferred credit will be recorded as a credit to tax expense when the future tax assets are realized. The final amount paid to New Hydrogenics, the retained tax attributes, future income tax asset and deferred credit in relation to the deferred tax asset are subject to final closing adjustments.

Also as a result of the Unit Exchange Offer, APUC will record an adjustment to future taxes. This adjustment will reflect the tax impact of recording future tax assets and liabilities for temporary differences in Algonquin's flow-through entities that are reversing or settling prior to 2011 which were previously not recorded since prior to the transactions these temporary difference reversals were not expected to be taxed in Algonquin. As at September 30 2009, this adjustment would be an increase in future tax expense of approximately \$0.4 million.

CD Exchange Offer

Under Canadian GAAP, based on the terms on the New Series 1 and New Series 2 convertible subordinated debentures issued by APUC in exchange for the Series 1 and Series 2 debentures, respectively, the exchange is considered a modification of the terms of the existing debentures rather than an extinguishment of the existing debentures as the present value of the cash flows of the liability component of both the Series 1 and Series 2 debentures did not change by more than 10% as compared to the terms of the original debentures. Accordingly, consolidated balance sheet will reflect the convertible debentures at their original carrying values, net of transaction costs associated with the CD Exchange Offer. These transaction costs which are recorded as deferred costs are amortized to interest expense over the remaining term of the convertible debentures using the effective interest rate method.

The conversion premium resulting from the conversion to the Series 1 debentures is accounted for as additional debt issuance costs and is amortized to interest expense over the remaining term of the convertible debentures using the effective interest rate method. The change in conversion price of the Series 1 convertible debentures under the CD Exchange Offer will result in a fair value of the conversion feature increasing by \$1.1 million compared to the original Series 1 debentures. The change in conversion price of the New Series 2 debentures under the CD Exchange Offer will result in a fair value of the conversion feature decreasing from the original Series 2 debentures carrying value of \$0.5 million to \$0.3 million. These changes in the fair value of the conversion features on the Series 1 and Series 2 debentures is recorded as a net additional discount on debt, with an offsetting net increase to equity. The discounts on debt are treated as additional debt issuance costs which are amortized to interest expense over the remaining term of the convertible debentures using the effective interest rate method.

In addition, an element of the CD Exchange Offer to the Series 1 debenture holders was an option to convert a portion of Series 1 debentures to equity at a rate of 311.52 APUC Shares for each \$1,000 principal amount of Series 1 debenture. Under Canadian GAAP this induced conversion option will result in an accounting debt settlement expense based on the value of the additional consideration inherent in the change in conversion ratio of approximately \$1.3 million. The CD Exchange Offer resulted in the holders of the Series 1 convertible debentures converting \$21.2 million of the outstanding principal balance of Series 1 debentures into 6,607,027 common shares of APUC.

The pro rata portion of existing deferred financing charges associated with the Series 1 debentures of approximately \$0.2 million will be recorded as a component of the amount recorded for the common shares issued on conversion. In addition, a proportionate allocation of the total deferred transaction costs associated with the CD Exchange Offer will be recorded part of the issuance costs of the new shares.

The exchange of \$63,755 of Series 1 convertible debentures that are not converted to shares, after adjustment for the 5% premium included in the CD Exchange Offer, will result in an increase in the principal balance of the Series 1 convertible debentures to \$66,943. The increase of \$3.2 million will be accounted for as additional debt issuance costs and will be amortized to interest expense over the term of the new convertible debentures using the effective interest rate method.

Changes in Accounting Policies

Algonquin's accounting policies are described in Note 1 to the Consolidated Financial Statements for the period ended September 30, 2009. There have been no changes to the critical accounting policies as disclosed in Algonquin's audited Consolidated Financial Statements for the period ended December 31, 2008 except as disclosed below.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, Algonquin has adopted EIC 173, Credit Risk and Fair Value of Financial Assets and Financial Liabilities, which clarifies that the credit risk of counterparties should be taken into account in determining the fair value of derivative instruments. EIC 173 has been applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value for the period ended September 30, 2009. The impact of adopting EIC 173 was a decline of \$2,542 to the recorded amount of the financial derivative liability and an increase of \$494 in future income tax liability at December 31, 2008 and a \$2,048 decrease in deficit. The impact of the change from December 31, 2008 to September 30, 2009 was not material.

Goodwill and Intangible Assets

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible Assets. Section 3064 states that upon their initial identification, intangible assets are to be recognized as assets only if they meet the definition of an intangible asset and the recognition criteria. This section also provides further information on the recognition of internally generated intangible assets. As for subsequent measurement of intangible assets, goodwill, and disclosure, Section 3064 carries forward the requirements of the old Section 3062, Goodwill and Other Intangible Assets. The new section became effective on January 1, 2009 for Algonquin.

Section 3064 was adopted retrospectively and prior periods have been restated to reflect the change. Costs related to deferred rate cases in the Utilities division were determined to not meet the definition of an intangible asset and the recognition criteria of Section 3064.

The effect of adopting Section 3064 on previously reported amounts is as follows:

	Year-ended December 31, 2008		
	Balance as previously reported	Adjustment	Balance as restated
Other assets	2,844	(1,053)	1,791
Future tax asset	2,894	410	3,304
Deficit	(358,904)	(643)	(359,547)

The impact on earnings for the three and nine months ended September 30, 2009 and the three and nine months ended September 30, 2008 was not material.

Future Accounting Changes not yet Adopted *Consolidated Financial Statements*

In January 2009, the CICA issued Handbook Section 1601, Consolidated Financial Statements, which replaces the existing standards. This section establishes the standards for preparing consolidated financial statements and is effective for 2011. Earlier adoption is permitted. Algonquin is currently evaluating the impact of adopting this standard on its consolidated financial statements.

Non-Controlling Interests

In January 2009, the CICA issued Handbook Section 1602, Non-Controlling Interests, which establishes

standards for the accounting of non-controlling interests of a subsidiary in the preparation of consolidated financial statements subsequent to a business combination. This standard is equivalent to the International Financial Reporting Standards on consolidated and separate financial statements. This standard is effective for 2011. Earlier adoption is permitted. Algonquin is currently evaluating the impact of adopting this standard on its consolidated financial statements.

Business Combinations

In January 2009, the CICA issued Handbook Section 1582, Business Combinations, which replaces the existing standards. This section establishes the standards for the accounting of business combinations, and states that all assets and liabilities of an acquired business will be recorded at fair value. Obligations for contingent considerations and contingencies will also be recorded at fair value at the acquisition date. The standard also states that acquisition-related costs will be expensed as incurred and that restructuring charges will be expensed in the periods after the acquisition date. This standard is equivalent to the International Financial Reporting Standards on business combinations. This standard is applied prospectively to business combinations with acquisition dates on or after January 1, 2011. Earlier adoption is permitted. Algonquin is currently evaluating the impact of adopting this standard on its consolidated financial statements.

Changeover to International Financial Reporting Standards

In 2011, Algonquin is required to change the accounting framework under which financial statements are prepared in Canada to International Financial Reporting Standards ("IFRS"). For the quarter ended March 31, 2011, Algonquin will report quarterly comparative financial information using IFRS. While the exact impact on Algonquin's financial statements of moving to IFRS is not completely known at this time; Algonquin conducted a high level diagnostic and qualitative assessment of its operations in order to identify the main areas where IFRS conversion will have the largest impact on Algonquin. Based on the analysis to date, areas of potential change may involve the valuation of property, plant and equipment, income taxes, business combinations, financial statement disclosure and initial adoption of IFRS under the provisions of IFRS 1, First-Time Adoption of IFRS. Experience in other jurisdictions has shown that earnings may tend to become more volatile and there will be an increase in the volume and complexity of financial disclosures. In July 2009, the International Accounting Standards Board ("IASB") issued an exposure draft providing guidance on recognition of regulatory assets and liabilities. The IASB plans to issue a standard in 2010, with an effective date of January 2011. Algonquin is in the process of evaluating the impact of this project on its adoption of IFRS as it relates to its utilities operations.

Algonquin has developed a conversion plan in order to ensure that it is prepared for the conversion and to minimize any disruption the conversion may cause. Algonquin's conversion plan addresses matters including detailed assessment of the effect of IFRS on its accounting policies, financial statements, internal control over financial reporting and information systems requirements, in addition to training and other related business matters. This conversion plan is subject to change as a result of ongoing and subsequent changes to IFRS standards and interpretations. Algonquin hired a specialist to co-ordinate and manage the changeover process. Algonquin's key personnel have received and will continue to invest in various training courses with regards to IFRS rules and the impact it will have on Algonquin's reporting requirements.

With regards to the impact of IFRS on Algonquin's banking and other financial covenants, Algonquin's senior secured revolving operating and acquisition credit facilities mature on January 14, 2011. Accordingly, Algonquin will be in a position to review and amend any financial covenants impacted by IFRS during the renewal process.

Algonquin's Audit Committee is involved with this process and will be provided formal updates on a quarterly basis and as required.

Consolidated Balance Sheets

(Unaudited) (thousands of Canadian dollars)

	September 30, 2009	December 31, 2008 (restated see note 2)
ASSETS		
Current assets:		
Cash	\$ 7,690	\$ 5,902
Accounts receivable	24,657	26,600
Prepaid expenses	3,363	2,832
Income tax receivable	1,272	1,538
Current portion of notes receivable	510	485
	37,492	37,357
Long-term investments and notes receivable	25,154	27,134
Future non-current income tax asset	3,624	3,304
Property, plant and equipment	761,372	804,965
Intangible assets	88,228	97,398
Restricted cash	4,597	5,295
Deferred financing costs	178	243
Other assets (notes 2 and 3)	5,057	1,791
	\$ 925,702	\$ 977,487
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 28,681	\$ 34,074
Distributions payable	1,587	1,587
Current portion of long-term liabilities	4,432	4,236
Current portion of derivative liabilities (note 10)	6,772	8,438
Current income tax liability	306	541
Future income tax liability	794	1,191
	42,572	50,067
Long-term liabilities	278,025	293,590
Convertible debentures	141,024	140,427
Other long-term liabilities	26,370	28,859
Future non-current income tax liability (note 2)	78,200	85,654
Derivative liabilities (notes 2 and 10)	5,714	25,116
Non controlling interest	10,096	12,548
Unitholders' equity:		
Trust units (notes 3 and 4)	726,861	722,215
Deficit	(338,898)	(359,547)
Accumulated other comprehensive loss	(44,262)	(21,442)
	343,701	341,226
Commitments and contingencies	\$ 925,702	\$ 977,487

See accompanying notes to consolidated financial statements

(signed) George Steeves (signed) Ken Moore

Consolidated Statement of Deficit

(Unaudited) (thousands of Canadian dollars)

	Three months ended September 30, 2009		September 30, 2008		Nine months ended September 30, 2009		September 30, 2008	
							(restated see note 2)	
Balance, beginning of period	\$	(347,295)	\$	(311,917)	\$	(358,904)	\$	(283,820)
Changes in accounting policies (note 2):								
Adjustments relating to adoption of HB 3064								
with restatement of prior periods		-		-		(643)		(667)
		(347,295)		(311,917)		(359,547)		(284,487)
Adjustments relating to adoption of EIC 173								
without restatement of prior periods		-		-		2,048		-
Balance, beginning of period as restated		(347,295)		(311,917)		(357,499)		(284,487)
Net earnings		13,078		(4,406)		32,623		2,057
Distributions		(4,681)		(17,506)		(14,022)		(51,399)
Balance, end of period	\$	(338,898)	\$	(333,829)	\$	(338,898)	\$	(333,829)

See accompanying notes to consolidated financial statements

Consolidated Statements of Comprehensive Income / (Loss) and Accumulated Other Comprehensive Income / (Loss)

(Unaudited) (thousands of Canadian dollars)

	Three months ended September 30, 2009		September 30, 2008		Nine months ended September 30, 2009		September 30, 2008	
Net earnings / (loss)	\$	13,078	\$	(4,406)	\$	32,623	\$	2,057
Other comprehensive income / (loss):								
Forward exchange contracts								
settled in the period		(279)		(680)		(1,692)		(2,623)
Translation of self sustaining foreign operations		(12,528)		6,737		(21,128)		2,515
Other comprehensive income / (loss)		(12,807)		6,057		(22,820)		(108)
Total comprehensive income / (loss)	\$	271	\$	1,651	\$	9,803	\$	1,949
Accumulated other comprehensive loss:								
Balance, beginning of the period	\$	(31,455)	\$	(50,055)	\$	(21,442)	\$	(43,890)
Other comprehensive income / (loss)		(12,807)		6,057		(22,820)		(108)
Balance, end of the period	\$	(44,262)	\$	(43,998)	\$	(44,262)	\$	(43,998)

See accompanying notes to consolidated financial statements

Consolidated Statements of Operations

(Unaudited) (thousands of Canadian dollars, except per unit amounts)

	Three months ended September 30, 2009		September 30, 2008		Nine months ended September 30, 2009		September 30, 2008	
Revenue:								
Energy sales	\$	30,139	\$	40,904	\$	100,013	\$	117,527
Waste disposal fees		3,821		4,098		10,682		11,709
Water reclamation and distribution		10,222		9,180		29,826		25,397
Other revenue		928		902		3,303		2,658
		45,110		55,084		143,824		157,291
Expenses								
Operating		24,219		31,997		78,796		87,875
Amortization of property, plant and equipment		9,700		9,241		29,059		26,851
Amortization of intangible assets		1,813		1,826		5,474		5,459
Management costs (note 5)		213		224		639		669
Administrative expenses		3,250		2,437		8,181		6,606
(Gain) / loss on foreign exchange		313		1,277		(1,003)		1,679
		39,508		47,002		121,146		129,139
Earnings before undernoted		5,602		8,082		22,678		28,152
Interest expense		5,086		6,774		15,742		20,576
Interest, dividend income and other income		(2,848)		(1,810)		(5,133)		(4,631)
(Gain) / loss on derivative financial instruments (note 10)		(7,100)		5,219		(15,803)		6,622
		(4,862)		10,183		(5,194)		22,567
Earnings from operations before income taxes and minority interest		10,464		(2,101)		27,872		5,585
Income tax expense (recovery)								
Current		167		287		631		481
Future		(3,091)		2,587		(7,896)		4,265
		(2,924)		2,874		(7,265)		4,746
Minority interest in earnings (loss) of subsidiaries		310		(569)		2,514		(1,218)
Net earnings / (loss)	\$	13,078	\$	(4,406)	\$	32,623	\$	2,057
Basic net earnings / (loss) per trust unit (note 6)	\$	0.17	\$	(0.06)	\$	0.42	\$	0.03
Diluted net earnings / (loss) per trust unit (note 6)	\$	0.17	\$	(0.06)	\$	0.42	\$	0.01

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

(Unaudited) (thousands of Canadian dollars)

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
Cash provided by (used in):				
Operating Activities:				
Net earnings / (loss)	\$ 13,078	\$ (4,406)	\$ 32,623	\$ 2,057
Items not affecting cash:				
Amortization of property, plant and equipment	9,700	9,241	29,059	26,851
Amortization of intangible assets	1,813	1,826	5,474	5,459
Other amortization	256	243	734	849
Distributions received in excess of equity income	(154)	339	1,336	354
Future income taxes / (recovery)	(3,091)	2,587	(7,896)	4,265
Gain on sale of land	(1,451)	-	(1,451)	-
Unrealized (gain) / loss on derivative financial instruments	(8,545)	6,479	(20,218)	11,785
Minority interest	310	(683)	2,514	(1,350)
Unrealized foreign exchange (gain) / loss on long-term debt	(68)	1,483	(958)	1,928
	11,848	17,109	41,217	52,198
Changes in non-cash operating working capital (note 8)	2,540	3,953	(3,744)	273
	14,388	21,062	37,473	52,471
Financing Activities:				
Cash distributions (note 7)	(4,681)	(16,969)	(14,022)	(50,859)
Cash distributions to non-controlling interest (notes 5 and 7)	(200)	(515)	(670)	(1,584)
Trustee loans	9	-	15	(225)
Deferred financing costs	5	(69)	(47)	(451)
Increase in long-term liabilities	-	18,917	14,000	56,917
Decrease in long-term liabilities	(5,685)	(24,120)	(24,261)	(39,168)
Increase in other long-term liabilities	(500)	(312)	126	(276)
	(11,052)	(23,068)	(24,859)	(35,646)
Investing Activities:				
Decrease / (increase) in restricted cash	215	1,260	122	3,920
Decrease / (increase) in other assets	(1,723)	857	(3,452)	1,134
Receipt of principal on notes receivable	94	79	351	1,789
Increase in long-term investments	-	(501)	-	(632)
Proceeds from liquidation of Highground assets (Note 3)	-	-	302	-
Proceeds from sale of land	2,502	-	2,502	-
Net additions to property, plant and equipment	(3,303)	(16,465)	(10,199)	(36,839)
Acquisition of Highground	-	18,633	-	18,633
Acquisitions of operating entities	-	(759)	(50)	(8,208)
	(2,215)	3,104	(10,424)	(20,203)
Effect of exchange rate differences on cash	(308)	193	(402)	378
Increase / (decrease) in cash	813	1,291	1,788	(3,000)
Cash, beginning of the period	6,877	6,070	5,902	10,361
Cash, end of the period	\$ 7,690	\$ 7,361	\$ 7,690	\$ 7,361
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	\$ 5,056	\$ 5,154	\$ 15,129	\$ 18,891
Cash paid / (received) during the period for income taxes	\$ (121)	\$ 386	\$ 816	\$ 1,186

See accompanying notes to consolidated financial statements

Notes to the Unaudited Interim Consolidated Financial Statements

Nine months ending September 30, 2009 and 2008 (in thousands of Canadian dollars except as noted and per trust unit)

1. Basis of presentation:

These unaudited interim consolidated financial statements of Algonquin Power Income Fund ("Algonquin") should be read in conjunction with the audited consolidated financial statements of Algonquin for the year ended December 31, 2008, as set out in Algonquin's 2008 annual report. The notes presented in these unaudited interim consolidated financial statements include only significant changes and transactions occurring since Algonquin's last year end, and are not fully inclusive of all disclosures required by Canadian generally accepted accounting principles for annual financial statements.

Algonquin's operating results are subject to seasonal fluctuations that materially impact quarter-to-quarter operating results and, thus, one quarter's operating results are not necessarily indicative of a subsequent quarter's operating results. Algonquin's hydroelectric energy assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally slower, while during the spring and fall periods flows are heavier. Algonquin's water and wastewater utility assets revenues fluctuate depending on demand for water. During drier, hotter periods of the year which occurs generally in the summer demand for water is generally higher than during cooler, wetter periods of the year.

These unaudited interim consolidated financial statements follow the same accounting policies and methods of application as the 2008 annual financial statements, except for the adoption of new accounting standards described in note 2.

2. Adoption of New Accounting Standards

CICA Section 3064 – Goodwill and intangible assets

Effective January 1, 2009, Algonquin has adopted the CICA Handbook Section 3064, Goodwill and intangible assets. Section 3064 states that upon their initial identification, intangible assets are to be recognized as assets only if they meet the definition of an intangible asset and the recognition criteria. This section also provides further information on the recognition of internally generated intangible assets. As for subsequent measurement of intangible assets, goodwill, and disclosure, Section 3064 carries forward the requirements of the old Section 3062, Goodwill and Other Intangible Assets.

Section 3064 was adopted retrospectively and prior periods have been restated to reflect the change. Costs related to deferred rate cases in the Utilities division were determined to not meet the definition of an intangible asset and the recognition criteria of Section 3064.

The effect of adopting Section 3064 on previously reported amounts is as follows:

	Year-ended December 31, 2008		
	Balance as previously reported	Adjustment	Balance as restated
Other assets	2,844	(1,053)	1,791
Future tax asset	2,894	410	3,304
Deficit	(358,904)	(643)	(359,547)

The impact on earnings for the three and nine months ended September 30, 2009 and the three and nine months ended September 30, 2008 was not material.

EIC 173, Credit Risk and Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, Algonquin has adopted EIC 173, Credit Risk and Fair Value of Financial Assets and Financial Liabilities, which clarifies that the credit risk of counterparties should be taken into account in determining the fair value of derivative instruments. EIC 173 has been applied retrospectively without restatement of prior periods to all financial assets and liabilities measured at fair value. The impact of adopting EIC 173 was a decline of \$2,542 to the recorded amount of the financial derivative liability and an increase of \$494 in future income tax liability at December 31, 2008 and a \$2,048 decrease in deficit.

3. Acquisitions

(a) Future acquisition of electrical generation and regulated distribution utility

On April 23, 2009, Algonquin announced that it plans to co-acquire an electrical generation and regulated distribution

utility through a strategic partnership with Emera Inc. ("Emera"). Algonquin and Emera will each own 50% of the newly formed California Pacific Electric Company ("California Pacific"), which intends to acquire the California-based electricity distribution and related generation assets (the "California Utility") of NV Energy, Inc. for the purchase price of approximately US \$116 million, subject to certain working capital and other closing adjustments. Algonquin and Emera will jointly own and operate the California Utility through California Pacific. The California Utility currently provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The transaction is subject to state and federal regulatory approval which management expects to occur in 2010.

As an element of the California Utility strategic partnership, Emera has also agreed to a conditional treasury subscription of approximately 8.5 million trust units of Algonquin at a price of \$3.25 per unit. Delivery of the trust units under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of the California Utility. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost of acquisition of the California Utility.

As of September 30, 2009, Algonquin has incurred costs of \$810 related to the strategic partnership with Emera. These costs are recorded as deferred transaction costs in other assets on the Consolidated Balance Sheet.

(b) Entrada Del Oro Sewer Company

On August 30, 2008, the Company entered into an agreement to acquire the shares of Entrada Del Oro Sewer Company located in Phoenix Arizona, for \$707 (US\$670) in the Utilities Services division. The earnings or loss from this acquisition have not been consolidated with Algonquin as formal approval from the regulator has not been received. Algonquin has accounted for this investment on an equity basis and has recorded a \$38 (U.S. \$33) (2008 - \$nil) net loss from the date of acquisition which has been recorded on the consolidated statement of earnings under interest, dividend income and other income and reduced other assets by a similar amount.

In accordance with the purchase and sale agreement for Entrada Del Oro Sewer Company, Algonquin is required to make additional payments to the previous owners for each additional customer connected to the utility. These payments continue until 2018. As of September 30, 2009 Algonquin has accrued \$88 (U.S. \$78) (September 30, 2008 - \$nil) as a growth premium, and increased other assets by a similar amount.

(c) Highground Capital Corporation

On August 1, 2008, the Company issued 3,507,143 trust units pursuant to an agreement entered into on June 27, 2008 between Algonquin, Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG"), which is the manager of Highground and a related party of Algonquin controlled by the shareholders of APMI, the managers of Algonquin. Under the agreement, CJIG acquired all of the issued and outstanding common shares of Highground and Algonquin issued 3,507,143 trust units of which 3,065,183 trust units were received by Highground shareholders as part of the Agreement with the remaining trust units being retained by CJIG.

Algonquin's final consideration for the trust units is dependent on the proceeds realized from liquidation of certain Highground investments. Algonquin's final consideration will be equal to the lesser of (a) \$26,970 plus 50% of the amount of the value of the assets formerly owned by Highground after payment of the transaction costs which is in excess of \$26,970 and (b) the value of all of the assets formerly owned by Highground after payment of the transaction costs, with the value of any non-cash securities received by Algonquin being determined through negotiation between the Trustees of Algonquin and CJIG.

During the second quarter of 2009, Algonquin received \$302 from Highground as Algonquin's share of the additional proceeds from the further liquidation of the assets held by Highground in excess of \$26,970. This has been recorded as an increased amount assigned to the trust units issued.

4. Trust Units

Trust Units consist of the following:

	Three months September 30, 2009	Three months September 30, 2008	Nine months September 30, 2009	Nine months September 30, 2008
Balance of Trust units, beginning of period	\$ 726,127	\$ 693,076	\$ 721,953	\$ 691,734
Issued on conversion of Algonquin (AirSource)				
Power LP exchangeable units	424	751	4,296	2,093
Issued pursuant to Highground transaction	-	26,203	-	26,203
Proceeds from liquidation of Highground assets (note 3(c))	-	-	302	-
Conversion of convertible debentures	33	-	33	-
Balance of Trust Units, end of period	\$ 726,584	\$ 720,030	\$ 726,584	\$ 720,030
Trustee Loans	(202)	(225)	(202)	(225)
Equity component of convertible debentures	479	479	479	479
Trust Units	\$ 726,861	\$ 720,284	\$ 726,861	\$ 720,284

Number of trust units

	Three months September 30, 2009	Three months September 30, 2008	Nine months September 30, 2009	Nine months September 30, 2008
Trust units, beginning of period	77,981,962	73,785,591	77,574,372	73,644,356
Issued on conversion of Algonquin (AirSource)				
Power LP exchangeable units	44,608	79,102	452,198	220,337
Conversion of convertible debentures	3,000	-	3,000	-
Issued pursuant to Highground transaction	-	3,507,143	-	3,507,143
Trust units, end of period	78,029,570	77,371,836	78,029,570	77,371,836

5. Related party transactions

Algonquin is managed by Algonquin Power Management Inc. ("APMI") which provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. An entity owned by the majority of the shareholders of APMI is the general partner of Algonquin Airlink Limited Partnership and is the general partner of Algonquin Property LP which leases the corporate office to Algonquin. Green Wing Algonquin Power Development Inc ("GWAP") is an entity majority owned by APMI which provides construction services. Collectively these entities are called the Algonquin Power Group.

For the nine months ended September 30, 2009, APMI was paid on a cost recovery basis for all costs incurred and charged \$639 (2008 - \$669).

As part of the project to re-power the Sanger facility, Algonquin entered into an agreement with APMI to undertake certain construction management services on the project. APMI is entitled to a development supervision fee plus a contingency fee for its construction management role on the project. During the nine month period ending September 30, 2009, APMI was paid \$nil (2008 - \$23).

Algonquin has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for the nine month period ending September 30, 2009 were \$249 (2008 - \$222).

Algonquin utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. During the nine month period ending September 30, 2009, Algonquin incurred costs in connection with the use of the aircraft of \$307 (2008 - \$183) and amortization expense related to the advance against expense reimbursements of \$118 (2008 - \$74).

In accordance with the construction services agreement related to the St. Leon facility, GWAP, a company controlled by APMI, was paid \$nil (2008 - \$134) during the nine month period ended September 30, 2009 for construction services.

Pursuant to the St. Leon Limited Partnership Agreement, in 2006, St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of Airsource and the legal owner of the St. Leon facility, was required to issue 100 Class B units to GWAP. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing after June 17, 2008, two years after the date the facility achieved commercial operations pursuant to the PPA. Such income allocations and cash distributions shall be increased by 2.5% for each successive 5 year period, to a maximum of 10.0%. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The holders of the Class B units are entitled to cash distributions of \$368 during the nine months ended September 30, 2009 (2008 - \$131).

On March 10, 2008, Algonquin advanced \$225 to the Trustees for purposes of enabling the Trustees to purchase additional Units of Algonquin. The loans are subject to promissory notes issued in favour of Algonquin which are payable upon demand, currently bear interest at 1% per annum, and are recorded as a reduction in Trust Units on the consolidated balance sheet. During the nine months ended September 30, 2009 principal repayments of \$15 were made (2008 - \$nil). Subsequent to the end of the quarter, the loans were fully repaid.

Pursuant to the Highground transaction that occurred on June 27, 2008 between Algonquin, Highground and CJIG, APMI was entitled to a fee of approximately \$240 which was recorded in 2008. This amount was paid in the second quarter of 2009.

APMI is entitled to 50% of the cash flow above 15% return on investment for the BCI project pursuant to its project management contract. During the nine months ended September 30, 2009 and 2008, no amounts were paid under this agreement. In 2008, APMI earned a construction supervision fee of \$100 in relation to the development of this project. As of September 30, 2009 this amount is accrued and included in accounts payable on the consolidated balance sheet.

6. Basic and diluted net earnings per trust unit

Basic and diluted earnings per trust unit have been calculated on the basis of the weighted average number of units outstanding during the period. The weighted average number of units outstanding during the period are as follows:

	Three months September 30, 2009	Three months September 30, 2008	Nine months September 30, 2009	Nine months September 30, 2008
Weighted average trust units – basic	78,002,990	76,112,073	77,878,983	74,526,647
Trust units issuable on conversion of exchangeable units	1,605,598	2,289,167	1,732,044	2,369,959
Weighted average trust units – diluted	79,608,588	78,401,240	79,611,027	76,896,606

Trust units issuable on conversion of exchangeable units are calculated based on the weighted average exchangeable units outstanding during the period at the period end exchange rate.

Units potentially issuable on the conversion of the convertible debentures are anti-dilutive and are not included in the calculation of diluted weighted average units for the three months and the nine months ended September 30, 2009 and September 30, 2008.

7. Cash distributions

All cash distributions of Algonquin are made on a discretionary basis as determined by the Trustees of Algonquin.

Distributions are declared to Unitholders of record on the last day of the month and are distributed 15 days after declaration. The monthly distribution in 2009 was \$0.02 per trust unit for each month for a total of \$0.06 for the three months ended September 30, 2009 and \$0.18 for the nine months ended September 30, 2009 (\$0.076 per trust unit per month and a total of \$0.23 for the three months ended September 30, 2008 and \$0.69 for the nine months ended September 30, 2008). Total distributions for the three months and nine months ended September 30, 2009 were \$4,681 and \$14,022 (2008 - \$16,969 and \$50,859).

Total distributions to the Unitholders of the Algonquin (Airsourc) Power LP exchangeable units for the three months and nine months ended September 30, 2009 were \$94 and \$302 (2008 - \$512 and \$1,584) which have been recorded as a reduction in non controlling interest on the unaudited consolidated Balance Sheet.

8. Non cash working capital

The change in non cash working capital is compromised of the following:

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
Accounts receivable	\$ 2,390	\$ (124)	\$ 2,146	\$ (5,009)
Income tax receivable	110	-	266	-
Prepaid expenses	271	1,159	(531)	356
Accounts payable and accrued liabilities	(410)	2,908	(5,390)	5,272
Current income tax liability	179	10	(235)	(346)
Change in non cash working capital	\$ 2,540	\$ 3,953	\$ (3,744)	\$ 273

9. Segmented Information

Algonquin identifies two business categories it operates in: Power Generation & Development, and Utility Services. The Power Generation & Development business unit develops and operates a portfolio of electrical energy generation facilities. Within this business unit there are three operational divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops Algonquin's greenfield power generation projects as well as any expansion of Algonquin's existing portfolio of renewable energy and thermal energy facilities.

The Utility Services business unit provides rate regulated transportation and delivery of water and wastewater in its service areas.

The operations and assets for these segments are as follows:

Geographic Segments

Algonquin and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	Three months September 30, 2009		Three months September 30, 2008		Nine months September 30, 2009		Nine months September 30, 2008	
Revenue								
Canada	\$	19,638	\$	20,910	\$	61,656	\$	62,782
United States		25,472		34,174		82,168		94,509
	\$	45,110	\$	55,084	\$	143,824	\$	157,291
					September 30, 2009		September 30, 2008	
Property, plant and equipment								
Canada					\$	449,244	\$	465,737
United States						312,128		318,464
					\$	761,372	\$	784,201
					September 30, 2009		September 30, 2008	
Intangible assets								
Canada					\$	49,085	\$	53,656
United States						39,143		41,495
					\$	88,228	\$	95,151
Other assets								
Canada					\$	3,415	\$	308
United States						1,642		86
					\$	5,057	\$	394

Revenues are attributable to the two countries based on the location of the underlying generating and utility facilities.

Reporting segments

The reporting segments are Renewable Energy, Thermal Energy and Utility Services. The development activities are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, Algonquin allocates the realized portion of the gain on derivative financial instruments to specific divisions. This allocation is determined when the initial foreign exchange forward contract is entered into. The unrealized portion of any gains or losses on derivative instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the Corporate segment. Interest expense is allocated to the divisions based on the project level debt related to the facilities in each division. Interest expense on the revolving credit facility and convertible debentures is reported in the Corporate segment. The interest rate swaps relate to specific debt facilities and gains and losses on these instruments are allocated in the same manner as interest expense.

The operations and assets for these segments are as follows:

Three months ending September 30, 2009							
	Power Generation & Development			Utility	Corporate		Total
	Renewable Energy	Thermal Energy	Total	Services			
Revenue							
Energy sales	\$ 15,198	\$ 14,941	\$ 30,139	\$ -	\$ -	\$	30,139
Waste disposal fees	-	3,821	3,821	-	-		3,821
Water reclamation and distribution	-	-	-	10,222	-		10,222
Other revenue	-	928	928	-	-		928
Total revenue	15,198	19,690	34,888	10,222	-		45,110
Operating expenses	4,932	13,102	18,034	6,185	-		24,219
	10,266	6,588	16,854	4,037	-		20,891
Other administration costs	(71)	(37)	(108)	-	(3,355)		(3,463)
Foreign exchange loss	-	-	-	-	(313)		(313)
Interest expense	(1,498)	(128)	(1,626)	(351)	(3,109)		(5,086)
Interest, dividend and other income	241	1,157	1,398	1,448	2		2,848
Gain / (loss) on derivative financial instruments	(591)	(147)	(738)	161	7,677		7,100
Amortization of property, plant and equipment	(4,190)	(3,277)	(7,467)	(2,233)	-		(9,700)
Amortization of intangible assets	(658)	(981)	(1,639)	(174)	-		(1,813)
Net earnings / (loss) before income taxes, minority interest	3,499	3,175	6,674	2,888	902		10,464
Property, plant and equipment	\$ 400,909	\$ 183,573	\$ 584,482	\$ 176,890	\$ -	\$	761,372
Intangible assets	31,280	31,421	62,701	25,527	-		88,228
Total assets	450,228	256,015	706,243	213,676	5,783		925,702
Capital expenditures	129	883	1,012	2,283	8		3,303
Acquisition of operating entities	-	-	-	-	-		-

Nine months ending September 30, 2009

	Power Generation & Development			Utility	Corporate	Total
	Renewable Energy	Thermal Energy	Total	Services		
Revenue						
Energy sales	\$ 51,623	\$ 48,390	\$ 100,013	\$ -	\$ -	\$ 100,013
Waste disposal fees	-	10,682	10,682	-	-	10,682
Water reclamation and distribution	-	-	-	29,826	-	29,826
Other revenue	-	3,303	3,303	-	-	3,303
Total revenue	51,623	62,375	113,998	29,826	-	143,824
Operating expenses	15,660	44,954	60,614	18,182	-	78,796
	35,963	17,421	53,384	11,644	-	65,028
Other administration costs	(171)	(126)	(297)	-	(8,523)	(8,820)
Foreign exchange gain	-	-	-	-	1,003	1,003
Interest expense	(4,629)	(421)	(5,050)	(1,151)	(9,541)	(15,742)
Interest, dividend and other income	793	2,877	3,670	1,411	52	5,133
Gain / (loss) on derivative financial instruments	2,456	(811)	1,645	316	13,842	15,803
Amortization of property, plant and equipment	(12,564)	(9,875)	(22,439)	(6,620)	-	(29,059)
Amortization of intangible assets	(1,975)	(2,933)	(4,908)	(566)	-	(5,474)
Net earnings / (loss) before income taxes, minority interest	19,873	6,132	26,005	5,034	(3,167)	27,872
Property, plant and equipment	\$ 400,909	\$ 183,573	\$ 584,482	\$ 176,890	\$ -	\$ 761,372
Intangible assets	31,280	31,421	62,701	25,527	-	88,228
Total assets	450,228	256,015	706,243	213,676	5,783	925,702
Capital expenditures	634	2,857	3,491	6,601	107	10,199
Acquisition of operating entities	-	-	-	50	-	50

Three months ending September 30, 2008

	Power Generation & Development			Utility	Corporate	Total
	Renewable Energy	Thermal Energy	Total	Services		
Revenue						
Energy sales	\$ 16,878	\$ 24,026	\$ 40,904	\$ -	\$ -	\$ 40,904
Waste disposal fees	-	4,098	4,098	-	-	4,098
Water reclamation and distribution	-	-	-	9,180	-	9,180
Other revenue	-	902	902	-	-	902
Total revenue	16,878	29,026	45,904	9,180	-	55,084
Operating expenses	5,304	21,029	26,333	5,664	-	31,997
	11,574	7,997	19,571	3,516	-	23,087
Other administration costs	(206)	61	(145)	(70)	(2,446)	(2,661)
Foreign exchange loss	-	-	-	-	(1,277)	(1,277)
Interest expense	(2,020)	(279)	(2,299)	(283)	(4,192)	(6,774)
Interest, dividend and other income	193	853	1,046	-	764	1,810
Gain / (loss) on derivative financial instruments	(1,226)	50	(1,176)	1,378	(5,421)	(5,219)
Amortization of property, plant and equipment	(5,483)	(2,120)	(7,603)	(1,638)	-	(9,241)
Amortization of intangible assets	(659)	(983)	(1,642)	(184)	-	(1,826)
Net earnings / (loss) before income taxes, minority interest	2,173	5,579	7,752	2,719	(12,572)	(2,101)
Property, plant and equipment	\$ 519,751	\$ 93,235	\$ 612,986	\$ 171,215	\$ -	\$ 784,201
Intangible assets	33,914	35,336	69,250	25,901	-	95,151
Total assets	571,236	174,987	746,223	206,614	9,926	962,763
Capital expenditures	678	694	1,372	15,058	35	16,465
Acquisition of operating entities	-	-	-	759	-	759

Nine months ending September 30, 2008

	Power Generation & Development			Utility		Corporate	Total
	Renewable Energy	Thermal Energy	Total	Services			
Revenue							
Energy sales	\$ 56,374	\$ 61,153	\$ 117,527	\$ -	\$ -	\$ -	117,527
Waste disposal fees	-	11,709	11,709	-	-	-	11,709
Water reclamation and distribution	-	-	-	25,397	-	-	25,397
Other revenue	-	2,658	2,658	-	-	-	2,658
Total revenue	56,374	75,520	131,894	25,397	-	-	157,291
Operating expenses	15,855	56,818	72,673	15,202	-	-	87,875
	40,519	18,702	59,221	10,195	-	-	69,416
Other administration costs	(350)	(102)	(452)	(203)	(6,620)	-	(7,275)
Foreign exchange loss	-	-	-	-	(1,679)	-	(1,679)
Interest expense	(6,450)	(786)	(7,236)	(718)	(12,622)	-	(20,576)
Interest, dividend and other income	970	2,797	3,767	47	817	-	4,631
Gain / (loss) on derivative financial instruments	(3,046)	1,816	(1,230)	3,606	(8,998)	-	(6,622)
Amortization of property, plant and equipment	(13,601)	(8,641)	(22,242)	(4,609)	-	-	(26,851)
Amortization of intangible assets	(1,958)	(2,951)	(4,909)	(550)	-	-	(5,459)
Net earnings / (loss) before income taxes, minority interest	16,084	10,835	26,919	7,768	(29,102)	-	5,585
Property, plant and equipment	\$ 519,751	\$ 93,235	\$ 612,986	\$ 171,215	\$ -	\$ -	784,201
Intangible assets	33,914	35,336	69,250	25,901	-	-	95,151
Total assets	571,236	174,987	746,223	206,614	9,926	-	962,763
Capital expenditures	1,483	5,377	6,860	29,868	111	-	36,839
Acquisition of operating entities	7,149	-	7,149	1,059	-	-	8,208

10. Derivative instruments**a) Foreign Currency Risk**

Algonquin uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from operations. Algonquin only enters into foreign exchange forward contracts with major Canadian financial institutions, thus reducing credit risk on these forward contracts. As at September 30, 2009, Algonquin had U.S. \$90,377 in outstanding foreign exchange forward contracts to sell U.S. dollars at an average rate of \$1.041. At September 30, 2009, the fair value of the foreign exchange forward contracts was a \$2,633 liability.

The following chart sets out the amount of foreign exchange forward contracts outstanding as at September 30, 2009, hedge proceeds and average hedged rates over the term of the contracts:

	Total	2009	2010	2011	2012	2013
Total U.S. \$ Hedged	\$ 90,377	\$ 7,522	\$ 33,165	\$ 29,660	\$ 16,640	\$ 3,390
Total Can. \$ Proceeds	\$ 94,080	7,952	34,507	30,427	17,443	3,751
Average Hedged Rate	\$ 1.041	\$ 1.057	\$ 1.040	\$ 1.026	\$ 1.048	\$ 1.107
Unrealized Gain (loss)	\$ (2,633)	(100)	(970)	(1,272)	(381)	90

b) *Interest Rate Risk*

Algonquin is exposed to interest rate fluctuations related to certain of its debt obligations, including certain project specific debt and its revolving credit facility.

Algonquin's project debt at the St. Leon facility has a balance of \$70,892 as at September 30, 2009. Algonquin has entered into a fixed for floating interest rate swap related to this debt covering the period to September 2015. At September 30, 2009, the fair value of the interest rate swap was a \$5,909 liability.

Algonquin's senior revolving credit facility has a balance of \$129,000 as at September 30, 2009. Algonquin has entered into a fixed for floating interest rate swap related to \$100,000 of this debt covering the period to December 2010. At September 30, 2009, the fair value of this interest rate swap was a \$3,944 liability.

As of September 30, 2009, the fair values of derivatives liabilities are as follows:

	September 30, 2009	December 31, 2008
Derivative liabilities:		
Foreign exchange forward contracts	\$ 2,633	\$ 16,735
Interest Rate swap – St. Leon	5,909	11,288
Interest Rate swap – revolving credit facility	3,944	5,531
	\$ 12,486	\$ 33,554
Less: current portion	(6,772)	(8,438)
Total long term derivative liabilities	\$ 5,714	\$ 25,116

Loss / (gain) on derivative financial instruments consist of the following:

	Three months September 30, 2009	Three months September 30, 2008	Nine months September 30, 2009	Nine months September 30, 2008
Unrealized loss / (gain) on derivative financial instruments:				
Foreign exchange contracts	\$ (7,696)	\$ 4,126	\$ (14,421)	\$ 7,890
Interest rate swaps	(849)	2,353	(5,797)	3,894
Total unrealized loss / (gain) on derivative financial instruments	\$ (8,545)	\$ 6,479	\$ (20,218)	\$ 11,784
Realized loss/(gain) on derivative financial instruments:				
Foreign exchange contracts	\$ (77)	\$ (1,428)	\$ 431	\$ (5,422)
Interest rate swaps	1,522	168	3,984	260
Total realized loss/(gain) on derivative financial instruments	\$ 1,445	\$ (1,260)	\$ 4,415	\$ (5,162)
Loss / (gain) on derivative financial instruments	\$ (7,100)	\$ 5,219	\$ (15,803)	\$ 6,622

11. Unit Exchange and Convertible Debenture Exchanges

(a) Unit for share exchange (the “Unit Exchange Offer”)

During the second quarter of 2009, the Board of Trustees of Algonquin (the “Board”) announced that they had entered into a unit-share exchange support agreement to support an offer (the “Unit Exchange Offer”) which would provide Algonquin’s unitholders the opportunity to exchange their trust units of Algonquin, on a one-for-one basis, for common shares of Hydrogenics Corporation an existing corporation which pursuant to a Plan of Arrangement would have all operations and existing shares transferred to a new Hydrogenics Corporation (“New Hydrogenics”) immediately before the Unit Exchange Offer occurs. The remaining Hydrogenics Corporation would be renamed following closing of the transactions contemplated by the Unit Exchange Offer.

Subsequent to September 30, 2009, on October 27, 2009 Algonquin unitholders exchanged 100% of outstanding trust units for a new class of common shares (“New Common Shares”) of Algonquin Power & Utilities Corp. (“APUC”), (formerly Hydrogenics Corporation), on a one for one basis. As a result, the existing unitholders of Algonquin became shareholders of APUC and Algonquin became a subsidiary entity of APUC. Excluding shares issued under the CD Exchange Offer (as defined below), the number of common shares of APUC outstanding immediately after completion of the transactions described herein would be exactly the same as the number of Algonquin trust units outstanding immediately before the Unit Exchange Offer.

As required under the Support Agreement, immediately following closing of the Unit Exchange Offer, APUC paid New Hydrogenics approximately \$10,813. APUC retains tax attributes of approximately \$192,000 which is in addition to the existing tax attributes of Algonquin.

(b) Convertible debenture exchange offer (the “CD Exchange Offer”)

During the second quarter of 2009, the Board also announced that, in conjunction with the Unit Exchange Offer, holders of Algonquin’s convertible debentures would be provided the opportunity to exchange their debentures for new debentures of APUC (the “CD Exchange Offer”) on the following terms:

In respect of the 6.65% convertible debentures maturing on July 31, 2011 (“Series 1”), holders of Series 1 debentures would receive, for each \$1 of Series 1 debenture principal, either of the following, at the option of each debenture holder to be exercised at the time of tender of their debentures:

(a) 311.52 common shares in APUC

- i. A maximum of 12,460,800 common shares was available under this option and, if demand for this option exceeded such amount, such shares would be allocated pro-rata amongst tendering debenture holders; or

(b) a convertible debenture issued by APUC (“New Series 1”) with the following terms:

- i. Principal: \$1.05
- ii. Coupon: 7.50%, payable semi-annually (Series 1 coupon is 6.65%)
- iii. Conversion Price: \$4.08 for each APUC share, representing a conversion premium of 20% over the most recent closing price of Algonquin’s trust units of \$3.40 (Series 1 conversion price is \$10.65 for each Algonquin trust unit).
- iv. Maturity: November 30, 2014

In respect of the 6.20% convertible debentures maturing on November 30, 2016 (“Series 2”), holders of the Series 2 debentures would receive, for each \$1 of Series 2 debenture principal, a convertible debenture issued by APUC (“New Series 2”) with the following terms:

- i. Principal: \$1.00
- ii. Coupon: 6.35%, payable semi-annually (current Series 2 coupon is 6.20%)
- iii. Conversion Price: \$6.00 for each APUC share (Series 2 conversion price is \$11.00 for each Algonquin trust unit)
- iv. Maturity: November 30, 2016

Subsequent to September 30, 2009, on October 27, 2009 holders of Algonquin's convertible debentures exchanged their convertible debentures for convertible debentures of APUC (the "New Debentures") or New Common Shares resulting in, among other things, Algonquin's debentureholders becoming debentureholders and shareholders of APUC.

Pursuant to the CD Exchange Offer, \$63,755 of the outstanding Series 1 debentures were exchanged for new Series 1 convertible unsecured subordinated debentures in a principal amount of \$66,943 and \$21,209 of the current Series 1 debentures were exchanged for 6,607,027 shares of APUC. In addition, all of the outstanding Series 2 convertible debentures were exchanged for New Series 2 convertible unsecured subordinated debentures in a principal amount of \$59,967.

The following is a description of the accounting treatment related to the Unit Exchange and CD Exchange.

Accounting Treatment of the Unit Exchange Offer

The Unit Exchange transaction has resulted in the Unitholders of Algonquin becoming shareholders of APUC and is required to be accounted for as a change in business form using the continuity of interests method. For the purposes of accounting, APUC is required to be accounted for as though it were a continuation of Algonquin but with its capital reflecting the exchange of APUC Shares for Trust Units and its future tax asset recognizing the tax attributes of Hydrogenics Corporation. Under this method, the transfer will be accounted for using the carrying amounts reflected in the consolidated financial statements of Algonquin. Comparative figures presented in the consolidated financial statements of APUC will include all amounts previously reported by Algonquin. The acquisition of tax attributes will be accounted for as future income tax assets recognized to the extent expected to be realized with any excess of the carrying amount recorded over the consideration paid to New Hydrogenics reflected as a deferred credit to be recognized in income as an income tax expense recovery as the future income tax assets are realized.

As a result of the Unit Exchange Offer, APUC paid New Hydrogenics approximately \$10,813. APUC retains tax attributes of approximately \$192,000 which is in addition to the existing tax attributes of Algonquin. APUC will recognize a future income tax asset of approximately \$62,200 and a deferred credit in relation to this asset of approximately \$50,400. The estimated amount of the future income tax asset, deferred credit and the amount of cash consideration are subject to final closing adjustments. For accounting purposes the deferred credit will be recorded as a credit to tax expense when the future tax assets are realized.

Also as a result of the Unit Exchange Offer, APUC will record an adjustment to future taxes. This adjustment will reflect the tax impact of recording future tax assets and liabilities for temporary differences in Algonquin's flow-through entities that are reversing or settling prior to 2011 which were previously not recorded since prior to the transactions these temporary difference reversals were not expected to be taxed in Algonquin. As at September 30 2009, this adjustment would be an increase in future tax expense of approximately \$400.

Accounting treatment of the CD Exchange Offer

Under Canadian GAAP, based on the terms on the New Series 1 and New Series 2 convertible subordinated debentures issued by APUC in exchange for the Series 1 and Series 2 debentures, respectively, the exchange is considered a modification of the terms of the existing debentures rather than an extinguishment of the existing debentures as the present value of the cash flows of the liability component of both the Series 1 and Series 2 debentures did not change by more than 10% as compared to the terms of the original debentures. Accordingly, consolidated balance sheet will reflect the convertible debentures at their original carrying values, net of transaction costs associated with the CD Exchange Offer. These transaction costs which are recorded as deferred costs are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

The conversion premium resulting from the conversion of the Series 1 convertible debentures is accounted for as additional debt issuance costs and is amortized to interest expense over the remaining term of the convertible debentures using the effective interest rate method. The change in conversion price of the New Series 1 convertible debentures under the CD Exchange Offer will result in the fair value of the conversion feature increasing by \$1,123 as compared to the original Series 1 debentures. The change in conversion price of the New Series 2 convertible debentures under the CD Exchange Offer will result in the fair value of the conversion feature decreasing from the original Series 2 convertible debentures carrying value of \$479 to \$308. The changes of \$1,123 and \$171 in the fair value of the conversion features on the Series 1 and Series 2

debentures are recorded as a change in the discount on debt, with an offsetting adjustment to equity. The discounts on debt are treated as additional debt issuance costs which are amortized to interest expense over the remaining terms of the convertible debentures using the effective interest rate method.

In addition, an element of the CD Exchange Offer to the Series 1 convertible debenture holders was an option to convert a portion of Series 1 convertible debentures to equity at a rate of 311.52 APUC Shares for each \$1 principal amount of Series 1 convertible debentures. Under Canadian GAAP this induced conversion option will result in an accounting debt settlement expense based on the value of the additional consideration inherent in the change in conversion ratio which is approximately \$1,250. The CD Exchange Offer resulted in the holders of the Series 1 convertible debentures converting \$21,209 of the outstanding principal balance of Series 1 convertible debentures into 6,607,027 common shares of APUC.

The pro rata portion of existing deferred financing charges associated with the Series 1 convertible debentures of approximately \$240 will be recorded as a component of the amount recorded for the common shares issued on conversion. In addition, a proportionate allocation of the total deferred transaction costs associated with the CD Exchange Offer will be recorded as part of the issuance costs of the new APUC shares.

The exchange of \$63,755 of Series 1 convertible debentures that are not converted to shares, after adjustment for the 5% premium included in the CD Exchange Offer, will result in an increase in the principal balance of the new Series 1 convertible debentures to \$66,943. The increase of \$3,188 will be accounted for as additional debt issuance costs and will be amortized to interest expense over the term of the new convertible debentures using the effective interest rate method.

12. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

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Chris Huskison – President and Chief Executive Officer, Emera Inc.
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