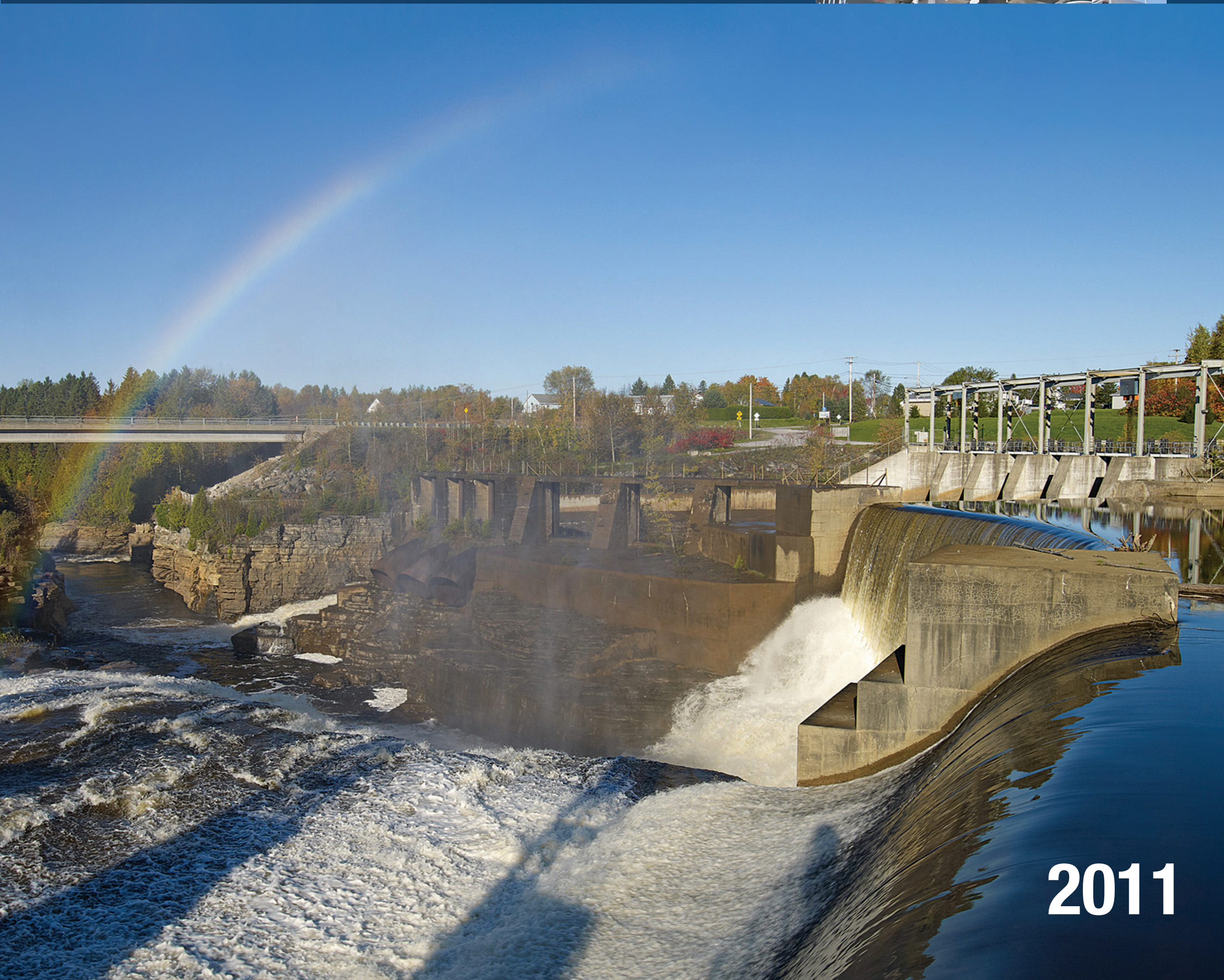
Algonquin Power & Utilities Corp.

Third Quarter Report



2011

Interim Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and nine months ended September 30, 2011. This interim Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's interim unaudited consolidated financial statements for the three and nine months ended September 30, 2011 and 2010 (the "Financial Statements"). This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of November 14, 2011.

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 APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC'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 APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require APUC to make assumptions and involve inherent risks and uncertainties. APUC cautions that although it believes its assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include 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 state of the Canadian and the United States ("U.S.") economies and accompanying business climate. APUC cautions that this list is not exhaustive, and other factors could adversely affect results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. APUC reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. APUC is not obligated to nor does it 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 "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") and "per share cash provided by operating activities" are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities" and Adjusted EBITDA are not recognized measures under U.S. generally accepted accounting principles ("GAAP"). There is no standardized measure of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" consequently APUC'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 "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" can be found throughout this MD&A.

Overview

APUC is incorporated under the Canada Business Corporations Act. APUC currently conducts its business primarily through two separate subsidiaries: Algonquin Power Co. ("APCo" or "Algonquin") owns and operates a diversified portfolio of renewable energy assets and Liberty Utilities Co. ("Liberty Utilities") owns and operates a portfolio of North American rate regulated utilities.

APCo generates and sells electrical energy through a diverse portfolio of renewable power generation and clean thermal power generation facilities across North America. As at September 30, 2011, APCo owns or has interests in hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds exchangeable debt securities in a 26 MW wind powered generating station recently completed in Saskatchewan. Approximately 92% of the electrical output from the renewable energy facilities is sold pursuant to long term power purchase agreements ("PPAs") with major utilities which have a weighted average remaining contract life of 13 years.

APCo's ownership interest in thermal energy facilities represents approximately 210 MW of installed generating capacity. Approximately 72% of the electrical output from these facilities is sold pursuant to long term PPAs with major utilities and which have a weighted average remaining contract life of 8 years.[1]

Liberty Utilities provides rate regulated electricity, natural gas and, water distribution and wastewater collection utility services. The utility businesses owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the States in which they operate. As a result of the current and expected growth of Liberty Utilities, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. As a result of this change, Liberty Utilities businesses operate under two separately managed regions – Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco).

Liberty Utilities (South) operates in the States of Arizona, Texas, Missouri and Illinois and currently provides rate regulated water and wastewater utility services to approximately 75,000 customers in those states.

Liberty Utilities (West) operates in the State of California and currently provides rate regulated local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region of California; on January 1, 2011, in partnership with Emera Inc. ("Emera"), Liberty Utilities (West) acquired the California-based electricity distribution utility and related generation assets (the "California Utility") from NV Energy.

[1] During the fourth quarter of 2010, APCo determined that the generating capacity reported for each of its facilities was more appropriately reported based on APCo's effective percentage ownership interest in the facility, rather than the total installed capacity of the facility; as a result, the generating capacity values set out in respect of some of the facilities included in APCo's generating portfolio have been reduced from prior periods.

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed to initially deliver electrical and natural gas distribution services to 126,000 customers acquired through the acquisition of Granite State Electric Company ("Granite State") and EnergyNorth Natural Gas, Inc., ("EnergyNorth"). Liberty Utilities (Central) will be created initially to manage the delivery of Liberty Utilities services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from ATMOS Energy Corporation.

Business Strategy

APUC's business strategy is to maximize long term shareholder value as a dividend paying, growth-oriented corporation in the independent power and rate regulated utilities business sectors. APUC is committed to delivering a total shareholder return comprised of dividends augmented by capital appreciation arising through dividend growth supported by increasing cash flows and earnings. Through an emphasis on sustainable, long-view renewable power and utility investments, over a medium-term planning horizon APUC strives to deliver annualized per share earnings growth of more than 5% and continued growth in its dividend supported by these increasing cash flows, earnings and additional investment prospects.

APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Additional increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") and dividend levels shall be reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to the APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

Independent Power: APCo seeks to deliver continuing growth through development of greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of expansion opportunities within APCo's existing portfolio of independent power facilities.

Utilities: Liberty Utilities' underlying business strategy is to be a leading provider of safe, high quality and reliable utility services through a nationwide portfolio of moderate sized utilities and deliver stable and predictable earnings to APUC from these utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings through acquisition opportunities which accretively expand its utility business portfolio.

Major Highlights

Corporate Highlights

Dividend Increased to $0.28 Per Common Share

On March 3, 2011, the Board approved an increase in the dividend from $0.24 to $0.26 on an annualized basis. On August 11, 2011, the Board approved a further dividend increase of $0.02 bringing the total dividend to $0.28, paid quarterly at the rate of $0.07 per common share. In approving the increase in dividends, the Board considered the continuing contributions of growth initiatives that began in 2010 and the significant progress made with regards to implementing additional growth initiatives announced in 2011 that have raised the growth profile for the Company's earnings and cash flows. These new growth initiatives, discussed in more detail below, include the acquisition of additional natural gas and electric utilities as well as new wind power generating projects to be built over the near term.

APUC believes that the increase in dividend is consistent with its stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation founded on increased earnings and cash flows.

Strengthened Liquidity - Issuance of $95.3 million of Common Shares

On October 27, 2011, APUC completed a public offering (the "Offering") of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. The net proceeds of the Offering will be used to fund a portion of the investment related to previously announced growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

Liberty Utilities Highlights

Filing of Approval Application for 100% of California Utility

On April 29, 2011, Emera agreed to sell its 49.999% direct ownership in the California Utility to Liberty Utilities, with closing of such transaction subject to regulatory approval. As consideration, Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities and the balance of the shares will be issued following completion of the California Utility's first rate case, expected to be completed in the latter half of 2012.

The acquisition of Emera's 49.999% interest in the California Utility requires approval by the California Public Utilities Commission. The application for approval has been filed. A prehearing conference with respect to Liberty Utilities' application is scheduled for November 30, 2011. APUC expects to receive a decision on the application in early 2012.

Regulatory Approval for New Hampshire Utility Acquisitions

The acquisitions of Granite State and EnergyNorth require approval by the New Hampshire Public Utilities Commission ("NHPUC"). The current procedural schedule for the approval of the acquisitions calls for a decision by the NHPUC in early 2012.

Regulatory Approval for Midwest Utility Acquisitions

The acquisition of rate regulated natural gas distribution utility assets (the "Midwest Gas Utilities") located in Missouri, Iowa, and Illinois requires approval by the respective state regulators. The current procedural schedule for the approval of the acquisitions calls for a decision by the Missouri Public

Service Commission and the Illinois Commerce Commission in the second quarter of 2012. A decision by the Iowa Utilities Board is expected in the fourth quarter of 2011.

Utility Acquisitions by Liberty Utilities (South)

On April 19, 2011, APUC announced that Liberty Utilities (South) had entered into asset purchase agreements to acquire three rate regulated water utility systems in the United States. Liberty Utilities (South) completed the acquisition of Noel Water Company ("Noel") during the third quarter and KMB Utilities Company ("KMB") subsequent to the end of the quarter. These acquisitions will expand Liberty Utilities (South)'s customer connections by approximately 1,000. Total consideration for the acquisitions is estimated at approximately U.S. $1.3 million.

Noel and KMB have net regulatory assets for rate making purposes of approximately U.S. $0.7 million, and U.S. $0.3 million respectively, representing a consolidated purchase price multiple of net regulatory assets of approximately 1.09x. KMB, located in Missouri, owns and operates rate regulated water distribution and waste-water collection and treatment utility systems; Noel participates solely in the rate regulated water distribution utility business in Missouri.

During the quarter ended September 30, 2011 and following the completion of due diligence investigations, Liberty Utilities (South) notified the seller of Louisiana Land and Water Co. that it intended to terminate the purchase agreement and would not proceed with the closing of the transactions as contemplated.

Algonquin Power Co. Highlights

St. Leon Facility Expansion Construction Commencement

On July 26, 2011, APCo announced that it had entered into a 25-year power purchase agreement with Manitoba Hydro in respect of a 16.5 MW expansion ("St. Leon II") of its existing St. Leon wind energy project located in the Province of Manitoba.

St. Leon II will be comprised of 10 Vestas V82-1.65 MW wind turbines, which already have been manufactured and are awaiting shipment to the site from a U.S. storage location. Permitting for the expansion project was completed in 2010. Construction commenced in the third quarter of 2011 with road construction and turbine foundations are expected to be completed in early November 2011. The project is expected to be commissioned in the first quarter of 2012 with total estimated capital costs of approximately $29.5 million. Expected annual energy production is approximately 58 GWhrs with the first full year of revenues following commissioning expected to be $3.8 million. Rates paid under the power purchase agreement are subject to a partial inflation adjustment that will be applied annually.

Acquisition of First Wind's Northeast Projects

On April 30, 2011, APUC, together with Emera and First Wind Holdings, LLC, entered into an agreement to jointly construct, own and operate wind energy projects in the Northeastern U.S. through a newly formed operating company. First Wind has a 370 MW portfolio of wind energy projects in the Northeast U.S. including six operating projects and one project near operation. These assets will become part of an operating company of which First Wind will own 51% and, Emera and APUC, through a separate joint venture ("Northeast Wind"), will own 49% of the operating company.

APUC and Emera will work with First Wind to expand the asset portfolio of the operating company through the development of other projects in the region. The transaction provides Northeast Wind access to a pipeline of Northeast US based development projects and provides APUC an effective way to extend its development reach into a geographic area which has historically not been included in its areas of focus. APUC is able to leverage its development activities through access to First Wind's development team within New England. APUC's involvement includes oversight control over the process which will result in additional projects being acquired by the joint venture. Once projects in the development pipeline meet certain eligibility criteria they will transfer to the operating company.

Northeast Wind will invest approximately U.S. $333,000 in the operating company, including a loan in the amount of U.S. $150,000, to acquire the 49% ownership of the operating company. APUC's investment in Northeast Wind will be approximately U.S. $83,000 for a 25% ownership interest. APUC will finance its equity investment in Northeast Wind, in part, through a subscription agreement with Emera to issue approximately 6.9 million shares at a price of $5.37 per share for proceeds of $37 million. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Northeast Wind.

Closing of the transaction is subject to certain conditions including regulatory approval and is expected to close in early 2012.

The First Wind projects being transferred to the operating company are:

Project	Location	Commercial Operation	Size
Mars Hill Wind,	Mars Hill, Maine	2007	42 MW
Stetson Wind I,	Danforth, Maine	2009	57 MW
Stetson Wind II,	Danforth, Maine	2010	26 MW
Rollins Wind	Lincoln, Maine	2011	60 MW
Sheffield Wind	Sheffield, Vermont	Q4 2011	40 MW
Steel Winds I	Lackawanna, New York	2007	20 MW
Cohocton Wind	Cohocton, New York	2009	125MW

Senior Unsecured Debentures

On July 25, 2011, APCo issued $135 million in senior unsecured debentures (the "Senior Unsecured Debentures"). The net proceeds from the Senior Unsecured Debentures were used to repay the outstanding senior project debt financing related to the St. Leon facility (the "AirSource Senior Debt") and to reduce amounts outstanding under APCo's senior revolving credit facility (the "Facility"). The Senior Unsecured Debentures mature on July 25, 2018, and bear interest at a rate of 5.50% per annum, calculated semi-annually payable on January 25 and July 25 each year, commencing on January 25, 2012.

2011 Nine month results from operations

APUC continued to show strong results through to the end of the third quarter of 2011. Over the past two years, APUC has focused its efforts on a number of value creation initiatives that, through their completion, are now contributing to the growth evident in APUC revenues, EBITDA and earnings. These initiatives include Liberty Utilities' acquisition of the California Utility and successful prosecution of rate cases, APCo's refurbishment of the Energy from Waste facility, acquisition of the Tinker Hydro facility and completion of construction and commissioning of the Red Lily I Wind Farm. As a result, for the nine months ended September 30, 2011, APUC reported total revenue of $204.6 million as compared to $131.9 million during the same period in 2010, an increase of $72.6 million or 55%. Adjusted EBITDA in the nine months ended September 30, 2011 totalled $80.9 million as compared to $54.3 million during the same period in 2010, an increase of $26.6 million or 49%. For the nine months ended September 30, 2011, net earnings attributable to Shareholders totalled $31.9 million as compared to $2.3 million during the same period in 2010, an increase of $29.6 million.

Key Selected Nine Month Financial Information

	Nine months ended September 30	
	2011 (millions)	**2010 (millions)**
Revenue	**$ 204.6**	$ 131.9
Adjusted EBITDA[1, 3]	**80.9**	54.3
Cash provided by Operating Activities	**65.1**	26.3
Net earnings attributable to Shareholders	**31.9**	2.3
Adjusted net earnings[1, 3]	**34.9**	4.3
Dividends paid to Shareholders	**22.9**	17.0
Per share		
Basic net earnings	**$ 0.29**	$ 0.02
Adjusted net earnings[1, 3]	**$ 0.31**	$ 0.05
Diluted net earnings	**$ 0.28**	$ 0.02
Cash provided by Operating Activities[2, 3]	**$ 0.58**	$ 0.28
Dividends paid to Shareholders	**$ 0.19**	$ 0.18
Total Assets	**1,263.1**	969.4
Long Term Liabilities (includes current portion)	**349.8**	253.0

1 APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.

2 APUC uses per share cash provided by operating activities to enhance assessment and understanding of the performance of APUC.

3 Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

The major factors resulting in the increase in APUC revenue in the nine months ended September 30, 2011 as compared to the corresponding period in 2010 are set out as follows:

	Nine months ended September 30, 2011 (millions)
Comparative Prior Period Revenue	$ 131.9
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	57.3
Energy-from-Waste facility	8.0
Liberty Utilities (South) revenue increases primarily due to rate case approvals	7.4
Effect of wind resource compared to comparable period in prior year	1.4
Effect of hydrology resource compared to comparable period in prior year	6.4
Tinker Hydro/ESB	(1.2)
Impact of the weaker U.S. dollar	(6.1)
Other	(0.5)
Current Period Revenue	$ 204.6

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the nine months ended September 30, 2011, APUC experienced an average U.S. exchange rate of approximately $0.978 as compared to $1.036 in the same period in 2010. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the nine months ended September 30, 2011 totalled $80.9 million as compared to $54.3 million during the same period in 2010, an increase of $26.6 million or 49%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved average hydrology and wind resources in APCo's Renewable Energy division and improved results from the EFW facility, partially offset by lower results at Windsor Locks, and the impact of the weaker U.S. dollar as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the nine months ended September 30, 2011, net earnings attributable to Shareholders totalled $31.9 million as compared to $2.3 million during the same period in 2010, an increase of $29.6 million. Basic net earnings per share totalled $0.29 for the nine months ended September 30, 2011, as compared to $0.02 during the same period in 2010.

For the nine months ended September 30, 2011, net earnings totalled $35.4 million as compared to $2.6 million during the same period in 2010, an increase of $32.8 million. A number of factors resulted in increased net earnings for the nine months ended September 30, 2011 including an increase of $29.3 million due to increased earnings from operating facilities, $12.1 million related to increased recoveries of income tax expense primarily due to the reasons discussed in Nine Month Corporate and Other Expenses – Income Taxes, $0.5 million due to decreased amortization expense, and $0.6 million related to increased gains on foreign exchange as compared to the same period in 2010. These items were partially offset by increased expenses of $2.9 million due to increased management and administration expense, $4.6 million due to increased interest expense, $1.3 million due to increased losses on derivative financial instruments and $1.1 million due to increased acquisition costs as compared to the same period in 2010.

A more detailed analysis of realized and unrealized mark to market gains and losses on foreign exchange contracts and interest swap contracts can be found later in this report under Treasury Risk Management - Foreign currency risk.

During the nine months ended September 30, 2011, cash provided by operating activities totalled $65.1 million or $0.58 per share as compared to cash provided by operating activities of $26.3 million, or $0.28 per share during the same period in 2010, an increase of approximately 107% per share. Cash per share provided by operating activities is a non-GAAP measure. Cash provided by operating activities exceeded dividends paid by 3.1 times during the nine months ended September 30, 2011 as compared to 1.6 times dividends paid during the same period in 2010. The change in cash provided by operating activities after changes in working capital in the nine months ended September 30, 2011, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2010.

2011 Three month results from operations

Key Selected Third Quarter Financial Information

	Three months ended September 30	
	2011	**2010**
Revenue	**$ 66.0**	$ 44.8
Adjusted EBITDA [1,3]	**$ 25.8**	$ 17.7
Cash provided by Operating Activities	**29.8**	5.3
Net earnings attributable to Shareholders	**19.6**	1.3
Adjusted net earnings[1,3]	**21.4**	1.2
Dividends paid to Shareholders	**8.3**	5.8
Per share		
Basic net earnings	**$ 0.16**	$ 0.01
Adjusted net earnings[1,3]	**$ 0.18**	$ 0.01
Diluted net earnings	**$ 0.16**	$ 0.01
Cash provided by Operating Activities [2,3]	**$ 0.25**	$ 0.06
Dividends paid to Shareholders	**$ 0.065**	$ 0.06

1 APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.

2 APUC uses per share cash from operating activities to enhance assessment and understanding of the performance of APUC.

3 Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

The major factors resulting in the increase in APUC revenue in the three months ended September 30, 2011 as compared to the corresponding period in 2010 are set out as follows:

		Three months ended September 30, 2011 (millions)
Comparative Prior Period Revenue	$	44.8
Significant Changes:		
Acquisition of the California Utility – January 1, 2011		17.0
Effect of hydrology resource compared to comparable period in prior year		2.8
Liberty Utilities (South) revenue increases primarily due to rate case approvals		2.7
Tinker Hydro/ESB		0.5
Impact of the weaker U.S. dollar		(2.0)
Other		0.2
Current Period Revenue	$	66.0

A more detailed discussion of these factors is presented within the business unit analysis.

APUC reports its results in Canadian dollars. For the three months ended September 30, 2011, APUC experienced an average U.S. exchange rate of approximately $0.980 as compared to $1.039 in the same period in 2010. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended September 30, 2011 totalled $25.8 million as compared to $17.7 million during the same period in 2010, an increase of $8.1 million or 46%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved hydrology in APCo's Renewable Energy division and the load supply and energy procurement business in Northern Maine ("ESB"), partially offset by lower results at Windsor Locks and the impact of the weaker U.S. dollar as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended September 30, 2011, net earnings attributable to Shareholders totalled $19.6 million as compared to $1.3 million during the same period in 2010, an increase of $18.3 million. Net earnings per share totalled $0.16 for the three months ended September 30, 2011, as compared to $0.01 during the same period in 2010.

For the three months ended September 30, 2011, net earnings totalled $20.4 million as compared to $1.4 million during the same period in 2010, an increase of $19.0 million. A number of factors resulted in increased net earnings for the three months ended September 30, 2011 including an increase of $8.8 million due to increased earnings from operating facilities, $14.5 million related to increased recoveries of income tax expense primarily due to the reasons discussed in Third Quarter Corporate and Other Expenses – Income Taxes, $0.6 million due to decreased amortization expense, and $0.3 million related to increased gains on foreign exchange as compared to the same period in 2010. These items were partially offset by increased expenses of $0.9 million due to increased management and administration expense, $1.1 million due to increased interest expense, $2.9 million due to increased losses on derivative financial instruments and $0.4 million due to increased acquisition costs as compared to the same period in 2010.

A more detailed analysis of realized and unrealized mark to market gains and losses on foreign exchange contracts and interest swap contracts can be found later in this report under Treasury Risk Management - Foreign currency risk.

During the three months ended September 30, 2011, cash provided by operating activities totalled $29.8 million or $0.25 per share as compared to cash provided by operating activities of $5.3 million, or $0.06 per share during the same period in 2010. Cash per share provided by operating activities is a non-GAAP measure. Cash provided by operating activities exceeded dividends paid by 3.8 times during the quarter ended September 30, 2011, as compared to 0.9 times during the same period in 2010. The change in cash provided by operating activities after changes in working capital in the three months ended September 30, 2011, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2010.

Outlook

APCo

The APCo Renewable Energy division is expected to perform in line with long-term average resource conditions for hydrology and long-term average wind resources in the fourth quarter of 2011.

APCo has commenced the repowering project at the Windsor Locks facility and has entered into an agreement with the steam host on an extension to the steam supply agreement. See APCo Development Division – Windsor Locks for further discussion on the repowering project.

APCo continues to have discussions with the Region of Peel regarding the processing of municipal solid waste at its APEFW facility following the end of the existing waste supply agreement in April 2012. In addition, APCo is investigating options with respect to processing of solid municipal waste from other sources as an alternative option to ensure a continued supply of waste for the facility.

Liberty Utilities

Liberty Utilities expects continuing modest customer growth at its facilities in 2011.

Revenue increases from rate cases completed in Arizona and Texas are anticipated to contribute additional revenue in Liberty Utilities (South) in the third quarter of 2011 as compared to the same period in 2010. Liberty Utilities attributes approximately U.S. $7.0 million of the revenue increases in the nine months ended September 30, 2011 to the impact of completed rate cases and anticipates that this will continue in the fourth quarter.

Liberty Utilities is pursuing additional investments in water, wastewater, electric and natural gas distribution utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best in-class-customer care for its subsidiary utility ratepayers.

APCo: Renewable Energy

	Three months ended September 30			Nine months ended September 30		
	Long Term Average Resource	2011	2010	Long Term Average Resource	2011	2010
Performance (GWhr sold)						
Quebec Region	**63.7**	**74.3**	50.2	**205.7**	**225.1**	191.7
Ontario Region	**29.2**	**23.8**	17.3	**102.5**	**92.3**	70.0
Manitoba Region	**76.0**	**80.8**	80.9	**267.0**	**264.1**	246.0
Saskatchewan Region*	**20.0**	**18.9**	-	**35.1**	**40.4**	-
New England Region	**7.6**	**9.0**	2.5	**45.5**	**46.5**	34.5
New York Region	**11.9**	**15.1**	11.2	**66.6**	**70.2**	55.2
Western Region	**23.8**	**22.0**	25.7	**53.2**	**53.7**	48.7
Maritime Region	**19.4**	**51.5**	19.5	**101.9**	**142.8**	93.0
Total	**251.6**	**295.4**	207.3	**877.5**	**935.1**	739.1
Revenue **						
Energy sales		**$ 19,197**	$ 16,058		**$ 63,750**	$ 58,250
Less:						
Cost of Sales – Energy***		**(691)**	(1,656)		**(3,025)**	(4,616)
Net Energy Sales		**$ 18,506**	$ 14,402		**$ 60,725**	$ 53,634
Other Revenue		**746**	562		**1,974**	1,559
Total Net Revenue		**$ 19,252**	$ 14,964		**$ 62,699**	$ 55,193
Expenses						
Operating expenses		**(5,967)**	(6,207)		**(18,182)**	(17,421)
Interest and Other income		**510**	230		**1,530**	632
Division operating profit (including other income)		**$ 13,795**	$ 8,986		**$ 46,047**	$ 38,404

* Actual production in the Saskatchewan Region reflects production since Red Lily I achieved commercial operation on February 23, 2011. The long term average resource reflects three and nine months of production.

** While most of APCo's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that 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.

*** Cost of Sales – Energy consists of energy purchases by the ESB which is resold to its retail and industrial customers. Under GAAP, in APUC's Financial Statements, these amounts are included in operating expenses.

2011 Nine Month Operating Results

For the nine months ended September 30, 2011, the Renewable Energy division produced 935.1 GWhrs of electricity, as compared to 739.1 GWhrs produced in the same period in 2010, an increase of 27%. The increased generation is primarily due to strong average hydrology in the quarter as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 69,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 515,000 tons of CO_2 gas was prevented from entering the atmosphere in the first three quarters of 2011.

During the nine months ended September 30, 2011, the division generated electricity equal to 107% of long-term projected average resources (wind and hydrology) as compared to 86% during the same period in 2010. In the first three quarters of 2011, the Maritime and Quebec regions experienced resources significantly higher than long-term averages, producing 40% and 10%, respectively, above long-term average resources, while the New York and New England regions experienced resources slightly higher than long-term averages, producing between 2 - 5% above long-term average resources. The Manitoba, Western regions experienced resources at long-term averages with the Ontario and Saskatchewan regions experienced resources between 7 - 10% below long-term averages.

For the nine months ended September 30, 2011, revenue from energy sales in the Renewable Energy division totalled $63.8 million, as compared to $58.3 million during the same period in 2010, an increase of $5.5 million or 9%. As the purchase of energy by the ESB is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the nine months ended September 30, 2011, net revenue from energy sales in the Renewable Energy division totalled $60.7 million, as compared to $53.6 million during the same period in 2010, an increase of $7.1 million or 13%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $4.6 million due to a 20% overall increase in hydrology and $0.9 million due to an increase in weighted average energy rates, primarily in the Quebec region, of approximately 3% as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $1.2 million due to increased average hydrology partially offset by $0.5 million due to a decrease in weighted average energy rates of approximately 9%. Revenue from the Manitoba region increased $1.0 million primarily due to a stronger wind resource and $0.2 million due to an increase in weighted average energy rates. Revenue in the Maritime region increased $0.3 million, primarily due to increased customer demand as compared to the same period in 2010. These increases were partially offset by a $1.5 million decrease in revenue at the ESB primarily due to decreased energy rates and customer demand as compared to the same period in 2010. Revenue at the ESB primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($8.1 million) and merchant sales of production in excess of customer demand and other revenue ($1.9 million). The division reported decreased revenue of $1.0 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

Red Lily I achieved commercial operations effective February 23, 2011. From the commercial operation date through September 30, 2011 Red Lily I produced 40.4 GWhrs of electricity. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily for a direct 75% equity interest in 2016. On the expectation that APCo will exercise such option, APCo proportionally includes the performance of Red Lily in its generation report. For the nine months ended September 30, 2011, APCo earned fees and interest payments from Red Lily I in the total amount of $2.8 million.

For the nine months ended September 30, 2011, energy purchase costs by the ESB totalled U.S. $3.1 million. During the first nine months, the ESB purchased approximately 32.4 GWhrs of energy at market and fixed rates averaging U.S. $67.50 per MWhr. The Maritime region generated approximately 75% of the load required to service its customers as well as the ESB' customers in the nine months ended September 30, 2011. The division reported decreased energy purchase costs of $0.2 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the nine months ended September 30, 2011, operating expenses excluding energy purchases totalled $18.2 million, as compared to $17.4 million during the same period in 2010, an increase of $0.8 million or 4%. Operating expenses were impacted by $1.3 million related to increased operating costs associated with the Tinker Assets and the ESB, primarily the result of higher production levels in the Maritime region as compared to the same period in 2010. These increases were partially offset by reduced operating expenses of approximately $0.5 million at the hydroelectric facilities. Operating expenses include costs incurred in the period of $0.9 million associated with the pursuit of various growth and development activities, an increase of $0.6 million as compared to the same period in 2010. In the prior period, APCo recorded a reduction in the development costs due to a reimbursement of $0.9 million in connection with the Red Lily I wind project. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the nine months ended September 30, 2011, interest and other income totalled $1.5 million, as compared to $0.6 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the nine months ended September 30, 2011, Renewable Energy's operating profit totalled $46.0 million, as compared to $38.4 million during the same period of 2010, representing an increase of $7.6 million or 20%. For the nine months ended September 30, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to increased hydrology in the Canadian regions.

2011 Third Quarter Operating Results

For the quarter ended September 30, 2011, the Renewable Energy division produced 295.4 GWhrs of electricity, as compared to 207.3 GWhrs produced in the same period in 2010, an increase of 42%. The increased generation is due to improved average hydrology in the quarter as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 65,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 160,000 tons of CO2 gas was prevented from entering the atmosphere in the third quarter of 2011.

During the quarter ended September 30, 2011, the division generated electricity equal to 117% of long-term projected average resources (wind and hydrology) as compared to 87% during the same period in 2010. In the third quarter of 2011, the Maritime region experienced resources significantly higher than long-term averages, producing 166% above long-term average resources, while the Quebec, New York and New England regions experienced resources higher than long-term averages, producing between 15 - 25% above long-term average resources. The Manitoba region experienced resources above long-term averages, producing approximately 5% above long-term average resources. The Western and Saskatchewan regions experienced resources between 5 - 8% below long-term averages while the Ontario region experienced resources of approximately 20% below the long-term average.

For the quarter ended September 30, 2011, revenue from energy sales in the Renewable Energy division totalled $19.2 million, as compared to $16.1 million during the same period in 2010, an increase of $3.1 million or 20%. As the purchase of energy by the ESB is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended September 30, 2011, net revenue from energy sales in the Renewable Energy division totalled $18.5 million, as compared to $14.4 million during the same period in 2010, an increase of $4.1 million or 28%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $0.6 million primarily due to an increase in weighted average energy rates of approximately 8% and $1.9 million due to a 30% overall increase in hydrology, primarily in the Quebec and Ontario regions as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $0.6 million primarily due to a 100% overall increase in average hydrology, partially offset by $0.3 million due to a decrease in weighted average energy rates of approximately 25% as compared to the same period in 2010. Revenue in the Maritime region increased $0.2 million, primarily due to increased customer demand as compared to the same period in 2010. The ESB experienced a $0.2 million increase in revenue primarily due to increased customer demand partially offset by reduced energy rates as compared to the same period in 2010. Revenue at the ESB primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($2.6 million) and merchant sales of production in excess of customer demand and other revenue ($0.7 million). Revenue from the Manitoba region increased $0.1 million primarily due to an increase in weighted average energy rates as compared to the same period in 2010. The division reported decreased revenue of $0.3 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

In the three months ended September 30, 2011 Red Lily I produced 18.9 GWhr of electricity which was sold to SaskPower. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. As discussed in the "Nine Months Operating Results" above, APCo proportionally includes the performance of Red Lily in its generation report. For the three months ended September 30, 2011, APCo earned fees and interest payments from Red Lily in the total amount of $0.8 million.

For the quarter ended September 30, 2011, energy purchase costs by the ESB totalled U.S. $0.6 million. During the quarter, the ESB purchased approximately 7.1 GWhr of energy at market and fixed rates averaging U.S. $58.50 per MWhr. The Maritime region generated approximately 90% of the load required to service its customers as well as the ESB's customers in the three months ended September 30, 2011.

For the quarter ended September 30, 2011, operating expenses excluding energy purchases totalled $6.0 million, as compared to $6.2 million during the same period in 2010, a decrease of $0.2 million or 4%.

Operating expenses were impacted by a $0.3 million decrease in operating costs at Canadian hydroelectric facilities, partially offset by an increase of $0.3 million related to increased operating costs associated with the Tinker Assets and the ESB as compared to the same period in 2010. Operating expenses include costs incurred in the period of $0.2 million associated with the pursuit of various growth and development activities, a decrease of $0.2 million as compared to the same period in 2010. The division reported decreased expenses of $0.2 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the quarter ended September 30, 2011, interest and other income totalled $0.5 million, as compared to $0.2 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the quarter ended September 30, 2011, Renewable Energy's operating profit totalled $13.8 million, as compared to $9.0 million during the same period of 2010, representing an increase of $4.8 million or 54%. For the quarter ended September 30, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to stronger hydrology in both the U.S. and Canadian regions.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the fourth quarter of 2011.

The ESB anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 32,000 MWhrs of energy to its customers in the fourth quarter of 2011. The ESB anticipates that the Tinker Assets will provide 75% of the energy required to service its customers in the third quarter of 2011 and that it will need to purchase approximately 8,000 MWhrs of energy from the ISO NE or similar market. The ESB has in place fixed price financial energy contracts to operationally hedge the price of the customer supply obligations which are not expected to be supplied by the Tinker Assets and to minimize the volatility of the energy prices. These contracts in combination with the expected Tinker production are used to balance the monthly customer load.

APCo: Thermal Energy Division

	Three months ended September 30		Nine months ended September 30	
	2011	**2010**	**2011**	**2010**
Performance (GWhr sold)	**131.6**	105.7	**390.5**	344.8
Performance (tonnes of waste processed)	**41,150**	40,620	**124,675**	47,170
Performance (steam sales – billion lbs)	**277.9**	272.7	**901.0**	864.4
Revenue				
Energy / steam sales	**$ 12,755**	$ 13,708	**$ 36,083**	$ 38,354
Less:				
Cost of sales – fuel *	**(5,942)**	(5,317)	**(17,202)**	(16,856)
Net energy / steam sales revenue	**$ 6,813**	$ 8,391	**$ 18,881**	$ 21,498
Waste disposal sales	**4,074**	3,868	**12,360**	4,875
Other revenue	**356**	354	**811**	898
Total net revenue	**$ 11,243**	$ 12,613	**$ 32,052**	$ 27,271
Expenses				
Operating expenses *	**(5,093)**	(5,374)	**(16,140)**	(15,977)
Interest and other income	**86**	19	**69**	537
Division operating profit (including interest and dividend income)	**$ 6,236**	$ 7,258	**$ 15,981**	$ 11,831

* Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities. Under GAAP, in APUC's Financial Statements, these amounts are included in operating expenses.

2011 Nine Month Operating Results

During the nine months ended September 30, 2011, the business unit produced 390.5 GWhr of energy as compared to 344.8 GWhr of energy in the comparable period of 2010. During the nine months ended September 30, 2011, the business unit's total production increased by 44.4 GWhr from the Windsor Locks facility and 6.0 GWhr from the EFW facility as compared to the same period in 2010. The comparable period includes 2.5 GWhr of production from landfill gas facilities which ceased generating energy and were closed in 2010.

The EFW facility processed 124,675 tonnes of municipal solid waste as compared to 47,170 tonnes processed in the same period of 2010. During the comparable period, the facility experienced an unplanned outage from January to July 2010 during which minimal waste was processed. The current level of production resulted in the diversion of approximately 88,500 tonnes of waste from municipal solid waste landfill sites in the first three quarters of 2011.

During the nine months ended September 30, 2011, the BCI and Windsor Locks facilities sold 901.0 billion lbs of steam as compared to 864.4 billion lbs of steam in the comparable period of 2010. During the nine months ended September 30, 2011, operations at the EFW facility generated 379 billion lbs of steam for the BCI facility as compared to 128 billion lbs of steam in the same period in 2010.

For the nine months ended September 30, 2011, energy / steam revenue in the Thermal Energy division totalled $36.1 million, as compared to $38.4 million during the same period in 2010, a decrease of $2.3 million, or 6%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the nine months ended September 30, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $18.9 million, as compared to $21.5 million during the same period in 2010, a decrease of $2.6 million, primarily arising from the weaker U.S. dollar and the termination of the previous power purchase agreements in effect until April 2010 at the Windsor Locks facility.

The overall decrease in revenue from energy / steam sales was primarily due to a decrease of $4.4 million at the Windsor Locks facility as a result of decreased average energy rates, in part due to the change in operating model of the facility, partially offset by an increase of $4.1 million as a result of increased production, as compared to the prior year. The Sanger facility experienced a net decrease of $0.3 million as a result of decreased energy pricing, in part due to lower average landed price per mmbtu for natural gas, partially offset by increased production. Energy / steam sales revenue decreased $0.3 million in the period as a result of the closure of the LFG facilities, as compared to the prior year. The decrease in revenue was partially offset by $0.5 million at the BCI and EFW facilities as a result of increased production of energy and improved pricing for steam, as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $1.9 million from operations as a result of the weaker U.S. dollar, as compared to the same period in 2010.

Revenue from waste disposal sales for the nine months ended September 30, 2011 totalled $12.4 million, as compared to $4.9 million during the same period in 2010. The increase was a result of the EFW facility unplanned outage from January to July 2010 in the comparable period of 2010.

For the nine months ended September 30, 2011, fuel costs at Sanger and Windsor Locks totalled $17.2 million, as compared with $16.9 million in the same period in 2010, an increase of $0.3 million.[2] The overall natural gas expense at the Windsor Locks facility increased U.S. $1.4 million (12%), primarily the result of a 10% increase in volume of natural gas consumed, as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the nine months was U.S. $4.87 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of U.S. $0.1 million (4%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the nine months was U.S. $4.57 per mmbtu. The division reported decreased fuel expenses of $1.0 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the nine months ended September 30, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $16.1 million, as compared to $16.0 million during the same period in 2010, an increase

[2] APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. Consequently the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other showing decreasing costs, as compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each mmbtu. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed per unit cost for natural gas combined with a consumption of a higher volume of such gas.

of $0.1 million. The increase in operating expenses for the nine months was primarily due to $4.3 million in increased gas, consumables, repair and maintenance and wages at the EFW facility resulting from the outage at the facility in 2010, partially offset by $1.9 million of reduced natural gas costs at BCI as a result of the EFW facility generating more steam and $1.0 million of reduced operating costs as a result of the closure of the land-fill gas facilities in 2010, as compared to the same period in 2010. Operating expenses in the comparable period included costs of $0.4 million associated with the pursuit of various growth and development activities. The division reported decreased expenses of $0.4 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the nine months ended September 30, 2011, the Thermal Energy division's operating profit totalled $16.0 million, as compared to $11.8 million during the same period in 2010, representing an increase of $4.2 million or 35%. Operating profit in the Thermal Energy division met expectations for the nine months ended September 30, 2011.

2011 Third Quarter Operating Results

During the quarter ended September 30, 2011, the business unit produced 131.6 GWhr of energy as compared to 105.7 GWhr of energy in the comparable period of 2010. During the quarter ended September 30, 2011, the business unit's total production increased by 22.8 GWhr from the Windsor Locks facility and 3.3 GWhr from the Sanger facility, as compared to the same period in 2010.

The EFW facility processed 41,150 tonnes of municipal solid waste as compared to 40,620 tonnes of municipal solid waste in the same period of 2010. The current level of production resulted in the diversion of approximately 29,300 tonnes of waste from municipal solid waste landfill sites in the third quarter of 2011.

During the quarter ended September 30, 2011, the BCI and Windsor Locks facilities sold 277.9 billion lbs of steam as compared to 272.7 billion lbs of steam in the comparable period of 2010. During the quarter ended September 30, 2011, operations at the EFW facility generated 124 billion lbs of steam for the BCI facility as compared to 110 billion lbs of steam in the same period in 2010.

For the quarter ended September 30, 2011, energy / steam revenue in the Thermal Energy division totalled $12.8 million, as compared to $13.7 million during the same period in 2010, a decrease of $0.9 million, or 7%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended September 30, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $6.8 million, as compared to $8.4 million during the same period in 2010, a decrease of $1.6 million, primarily arising from the weaker U.S. dollar and in 2010 the Windsor Locks facility derived revenues from the Forward Reserve Market whereas in 2011 the facility was selling into the ISO-NE day-ahead market. The decision to have the facility not participate in the Forward Reserve Market in 2011 was due to the fact that it could earn more selling into the ISO-NE day-ahead market compared to the lower prices offered for participating the Forward Reserve Market in 2011.

The decrease in revenue from energy / steam sales was primarily due to a decrease of $2.8 million at the Windsor Locks facility as a result of decreased energy rates, in part due to a lower average landed price per mmbtu for natural gas and the change in operating model of the facility, partially offset by an increase of

$2.4 million at the Windsor Locks facility due to increased production and a net increase of $0.2 million at the Sanger facility as a result of the change in energy pricing and production as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $0.7 million from operations as a result of the weaker U.S. dollar, as compared to the same period in 2010.

Revenue from waste disposal sales for the quarter ended September 30, 2011 totalled $4.1 million, as compared to $3.9 million during the same period in 2010. The increase was a result of the unplanned outage at the EFW facility for approximately two weeks in the comparable period of 2010.

Other revenue for the quarter ended September 30, 2011 totalled $0.4 million, consistent with the same period in 2010.

For the quarter ended September 30, 2011, fuel costs at Sanger and Windsor Locks totalled $5.9 million, as compared to $5.3 million in the same period in 2010, an increase of $0.6 million.[3] The overall natural gas expense at the Windsor Locks facility increased U.S. $0.8 million (20%), primarily the result of a 19% increase in volume of natural gas consumed, as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the quarter was U.S. $5.03 per mmbtu. The overall natural gas expense at the Sanger facility increased U.S. $0.2 million (13%), primarily the result of a 9% increase in the volume of natural gas consumed as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.55 per mmbtu. The division reported decreased fuel expenses of $0.3 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the quarter ended September 30, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.1 million, as compared to $5.4 million during the same period in 2010, a decrease of $0.3 million. The decrease in operating expenses for the quarter was primarily due to $0.3 million of reduced operating costs due to the closure of the land-fill gas facilities in the prior year, offset by $0.4 million in increased operating costs at the EFW facility as compared to the same period in 2010. The division reported decreased expenses of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the quarter ended September 30, 2011, the Thermal Energy division's operating profit totalled $6.2 million, as compared to $7.3 million during the same period in 2010, representing a decrease of $1.0 million or 14%. Operating profit in the Thermal Energy division met expectations for the quarter ended September 30, 2011.

Divisional Outlook – Thermal Energy

The capital upgrade completed at the EFW facility is expected to continue to result in higher throughput and lower operating costs at the facility in the fourth quarter of 2011 consistent with the results experienced in the first three quarters of 2011.

[3] APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. Consequently the average landed cost per unit of natural gas will differ between facility and regional changes in the average landed cost for natural gas may result in one facility showing increasing costs per unit while the other showing decreasing costs, as compared to the same period in the prior year. Total natural gas expense will vary based on the volume of natural gas consumed and the average landed cost of natural gas for each mmbtu. As a result, a facility may record a higher aggregate expense for natural gas as a result of a lower average landed per unit cost for natural gas combined with a consumption of a higher volume of such gas.

APCo anticipates that the Sanger facility should meet expectations for the fourth quarter of 2011 and be in line with 2010 results.

APCo Thermal Energy division's Windsor Locks facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO NE day-ahead market or to industrial customers through the Energy Services Business. It is anticipated that performance during the fourth quarter of 2011 will be in line with expectations.

APCo has commenced the repowering project at the Windsor Locks facility and has entered into an agreement with the steam host on an extension to the steam supply agreement. See APCo Development Division – Windsor Locks for further discussion on the potential repowering project.

APCo continues to have discussions with the Region of Peel regarding the processing of municipal solid waste at its APEFW facility following the end of the existing waste supply agreement in April 2012. In addition, APCo is investigating options with respect to processing of solid municipal waste from other sources as an alternative option to ensure a continued supply of waste for the facility.

APCo: Development Division

Current Development Projects

APCo's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of Power Purchase Agreements. The projects are as follows:

Project Name (Location)	Size (MW)	Estimated Capital Cost	Expected Year of Commissioning	PPA Term	Production MWhr
Amherst Island (Ontario)[1]	75	$230m	2014	25	247,000
St. Damase (Quebec)[2]	24	$70m	2013	20	86,000
Val Eo (Quebec)[2]	24	$70m	2015	20	66,000
Morse (Saskatchewan) [3,4]	25	$70m	2013	20	93,000
St. Leon II[2]	17	$30m	2012	25	58,000
Total	**165**	**$470m**			**550,000**

Notes:

1. FIT contract awarded
2. PPA signed
3. Two 10 MW PPAs; one 5 MW PPA
4. Comprised of three projects that are connected geographically and will be built simultaneously. All three projects were awarded PPAs under the province's Green Options Partner Program ("GOPP").

St. Leon II

In July 2011, APUC announced the execution of a 25-year power purchase agreement with Manitoba Hydro in respect of St. Leon II (a 16.5 MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba).

In the first full year of production following commissioning, APUC anticipates generating annual gross revenues of $3.8 million. St. Leon II is expected to produce approximately 58,000 MWhrs annually. Rates paid under the power purchase agreement are subject to a partial inflation adjustment that will be applied annually. Construction of the expansion is underway with all access roads and foundations expected to be completed in early November 2011. The 10 Vestas V82-1.65 MW wind turbines that will comprise the expansion, have already been manufactured and are in the process of being shipped to the project site from a U.S. storage location. Commissioning of the expansion project is expected to occur in first quarter of 2012 with total forecast capital costs of $29.5 million.

Amherst Island

The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. The 75 MW project was awarded a FIT contract by the Ontario Power Authority ("OPA") as part of the second round of the OPA's Feed-in Tariff ("FIT") program.

The FIT contract originally stated that the OPA had the option to terminate the FIT contract prior to the date that the OPA had issued a Notice to Proceed ("NTP") and APCo had paid the incremental security required by the NTP. On August 2, 2011, the Ontario Ministry of Energy directed the OPA to offer FIT contract holders the opportunity to have the OPA's termination rights under the FIT contract waived. APCo exercised this option on August 9, 2011. As required by the waiver, APCo submitted a domestic content plan on October 14, 2011 and will provide a statutory declaration regarding equipment supply commitments by November 30, 2011. APCo expects to complete the waiver requirements within the time frames set out in the waiver.

The project is currently contemplated to use more efficient Class III wind turbine generator technology. APCo forecasts that the available wind resource could produce approximately 247 GWhr of electrical energy annually, depending upon the final turbine selection for the project. Funding for the total capital costs, currently estimated to be $230 million, will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied. Environmental studies and engineering are underway. The submission of the renewable energy application is targeted for the summer of 2012. Construction will commence shortly following the approval of the application and is expected to take 12 to 18 months.

Quebec Community Wind Projects

In 2010, APCo worked with Société en Commandite Val-Éo, a community cooperative with a development project located in the Lac Saint-Jean region of Quebec, and the community of Saint-Damase to submit proposals into Hydro Quebec's 250 MW wind Request for Proposal. On December 20, 2010, both projects were awarded power purchase contracts that stipulate the use of ENERCON wind turbines.

Saint-Damase

The Saint-Damase Wind Project is located in the local municipality of Saint-Damase which is within the regional municipality of la Matapédia. The project proponents include the Municipality of Saint-Damase and APCo. The first 24 MW phase of the project is expected to be comprised of eight to twelve generators (depending on capacity of the selected wind turbine model), producing approximately 86,000 MWhr annually. Construction of the first 24 MW phase of the project is estimated to begin in early 2013 with a commercial operations date in late 2013.

The interest of APUC in the project is subject to final negotiations with the municipality but, in any event, will not be less than 50%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing. In July 2011, meetings were conducted with participating landowners in addition to an open house to obtain additional community feedback. All major environmental authorizations are targeted for completion by the end of 2012.

Val-Éo

The Val-Éo Wind Project is located in the local municipality of Saint-Gédéon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and APCo. The first 24 MW phase of the project is expected to be comprised of eight generators, producing approximately 66,000 MWhr annually. Construction of the first 24 MW phase of the project is expected to begin in early 2015 with commercial operations occurring in late 2015.

The interest of APUC in the project is subject to final negotiations with the cooperative but, in any event, will not be less 25%. Final funding of the project will be arranged and announced when all required permitting has been met, and all other pre-construction conditions have been satisfied. Preliminary permitting began in early 2011 and studies of flora and fauna and the public consultation process are ongoing with all major authorizations targeted for completion by the end of 2012.

Morse Wind Project

The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. It is contemplated that the project will have additional land under lease or under option in order to facilitate future expansion.

APCo executed an asset purchase agreement with a local developer (“Kineticor”) to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APCo independently. All of the individual projects comprising the Morse Wind Project were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program. Two 10 MW PPA’s were awarded in May 2010 and a further 5 MW awarded in June of this year. Upon SaskPower’s approval and execution of the Kineticor PPAs, Kineticor will then assign the PPAs to APCo. All three of the projects are expected to be completed contemporaneously in early 2014.

The total annual energy production for the Morse Wind Project is estimated to be 93,000 MWhr. The capital cost to construct the Morse Wind Project is currently estimated to be $65-$70 million, inclusive of acquisition costs. The first year PPA rate is set at $101.98 per MWhr for the first full year of operations, which APCo expects to occur in 2014, with an annual escalation provision of 2% over the expected 20 year term.

Red Lily II Wind Project

APCo has secured additional land options related to property around the Red Lily I project to facilitate a 106 MW expansion (“Red Lily II”). The viability of the expanded project will be conditional upon a review of the actual operating results from Red Lily I.

SaskPower Request for Wind Proposals

During the first quarter of 2010, APCo responded to the request for quotations issued by SaskPower for a 175 MW of wind power generation. In this regard, APCo has submitted an 87.5 MW and a 175 MW proposal in response to this call. SaskPower is expected to award one 175 MW power purchase agreement or two 87.5 MW power purchase agreements in the first quarter of 2012.

Windsor Locks Repowering

The Windsor Locks Facility is a 54 MW natural gas powered electrical and steam energy generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to an energy services agreement ("ESA").

APCo has entered into a revised to the ESA, the term of which continues until 2027, with Ahlstrom for the installation of a 14.2 MW Solar combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Windsor Locks Facility of approximately U.S. $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO NE market. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("ITC") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant.

Liberty Utilities

Liberty Utilities' business strategy is to operate and grow its nationwide portfolio of rate regulated water, natural gas and electric distribution and wastewater collection and treatment utilities and electric transmission assets, sharing certain common infrastructure between utilities to support best-in-class customer care for all utility ratepayers and building constructive regulatory relationships in the jurisdictions in which it operates.

As a result of the current and expected growth with Liberty Utilities, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. This approach will also enhance operational efficiencies and garner greater economies of scale while preserving the customer and regulator focus of the businesses which arises from the independent operations of these regions. As a result of this change Liberty Utilities now has two separately managed regions – Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco).

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed initially to deliver electrical and natural gas distribution services to the 126,000 customers acquired through the acquisition of Granite State and EnergyNorth. A fourth management region, Liberty Utilities (Central), will initially be created to manage the delivery of Liberty Utilities services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from ATMOS Energy Corporation. It is contemplated that certain Missouri based water and wastewater utilities will be transferred from the South region to the Central region upon its creation.

Liberty Utilities is committed to being a leading utility provider of water, natural gas and electric utility services while providing stable and predictable earnings to APUC from its utility operations. Liberty Utilities has presented the division's results in both the reporting currency and its functional currency. Liberty Utilities believes that since the division's operations are entirely in the U.S., it is useful to show the results in Liberty Utilities' functional currency without the impact of foreign exchange.

Liberty Utilities (South) (formerly Liberty Water)

Liberty Utilities (South) operates in Arizona, Texas, Missouri and Illinois and currently provides rate regulated water and wastewater utility services to approximately 75,000 customers in those states.

	Nine months ended September 30		Nine months ended September 30	
	2011	**2010**	**2011**	**2010**
Number of				
Wastewater connections			**36,550**	35,277
Wastewater treated (millions of gallons)			**1,500**	1,500
Water distribution connections			**38,050**	37,450
Water sold (millions of gallons)			**4,300**	4,100
	U.S. $	U.S. $	**Can $**	Can $
NBV of Assets for regulatory purposes (U.S. $)	**156,695**	154,054		
Revenue				
Wastewater treatment	**$ 17,440**	$ 14,645	**$ 17,049**	$ 15,267
Water distribution	**16,349**	11,781	**15,982**	12,281
Other Revenue	**503**	414	**492**	454
	$ 34,292	$ 26,840	**$ 33,523**	$ 28,002
Expenses				
Operating expenses	**(17,058)**	(16,107)	**(16,681)**	(16,829)
Other income	**258**	65	**264**	68
Division operating profit	**$ 17,492**	$ 10,798	**$ 17,106**	$ 11,241

Liberty Utilities reports total connections, inclusive of vacant connections rather than customers. Liberty Utilities (South) had 36,550 wastewater connections as at September 30, 2011, as compared to 35,277 as at September 30, 2010, an increase of 1,273 connections in the period or 3.6%. Liberty Utilities (South) had 38,050 water distribution connections as at September 30, 2011, as compared to 37,450 as at September 30, 2010, representing an increase of 600 in the period or 1.6%. Total connections include approximately 1,800 vacant wastewater connections and 1,300 vacant water distributions connections as at September 30, 2011. Liberty Utilities (South)'s change in water distribution and wastewater treatment customer base during the period is primarily due to modest customer growth within Liberty Utilities (South)'s service territories.

Liberty Utilities (South) has investments in regulatory assets with a net book value of U.S. $156.7 million across four states as at September 30, 2011, as compared to U.S. $154.1 million as at September 30, 2010.

2011 Nine Month Operating Results

During the nine months ended September 30, 2011, Liberty Utilities (South) provided approximately 4.3 billion U.S. gallons of water to its customers, treated approximately 1.5 billion U.S. gallons of wastewater and sold approximately 235 million U.S. gallons of treated effluent.

For the nine months ended September 30, 2011, Liberty Utilities (South)'s revenue totalled U.S. $34.3 million as compared to U.S. $26.8 million during the same period in 2010, an increase of U.S. $7.5 million or 28%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state regulators over the past two years. Rate cases ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates.

Revenue from wastewater treatment totalled U.S. $17.4 million, as compared to U.S. $14.6 million during the same period in 2010, an increase of U.S. $2.8 million or 19%. The nine month wastewater treatment revenue was impacted by increased revenue, primarily from the implementation of rate increases of U.S. $2.2 million at the Litchfield Park ("LPSCo") facility and U.S. $0.4 million at the Black Mountain facility as compared to the same period in 2010. In addition, revenue increased U.S. $0.3 million at eight wastewater treatment facilities primarily due to increased customer demand as compared to the same period in 2010.

Revenue from water distribution totalled U.S. $16.3 million, as compared to U.S. $11.8 million during the same period in 2010, an increase of U.S. $4.6 million or 39%. The nine month water distribution revenue was impacted, primarily due to the implementation of rate increases of U.S. $3.3 million at the LPSCo facility, U.S. $0.7 million at the Rio Rico facility and U.S. $0.5 million at the Bella Vista facility as compared to the same period in 2010. In addition, revenue increased U.S. $0.2 million at eight water distribution facilities primarily due to increased customer demand as compared to the same period in 2010.

For the nine months ended September 30, 2011, operating expenses totalled U.S. $17.1 million, as compared to U.S. $16.1 million during the same period in 2010. Overall expenses increased U.S. $1.0 million or 6% as compared to the same period in 2010. Operating expenses increased due to increased utilities, consumable and insurance expenses of U.S. $0.4 million and U.S. $0.6 million related to increased wages, salary and other operating costs as compared to the same period in 2010.

For the nine months ended September 30, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $17.5 million as compared to U.S. $10.8 million in the same period in 2010, an increase of U.S. $6.7 million or 62%. Liberty Utilities (South)'s operating profit exceeded expectations for the nine months ended September 30, 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2011, Liberty Utilities (South)'s revenue totalled $33.5 million, as compared to $28.0 million during the same period in 2010. Revenue from wastewater treatment totalled $17.0 million, as compared to $15.3 million during the same period in 2010, an increase of $1.8 million. Revenue from water distribution totalled $16.0 million, as compared to $12.3 million in the same period in 2010, an increase of $3.7 million. Liberty Utilities (South) reported decreased revenue from operations of $1.9 million in the first nine months of 2011 as a result of the weaker U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the nine months ended September 30, 2011, operating expenses totalled $16.7 million, consistent with same period in 2010. Liberty Utilities (South) reported lower expenses from operations of $1.1 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the nine months ended September 30, 2011, Liberty Utilities (South)'s operating profit totalled $17.1 million as compared to $11.2 million in the same period in 2010, an increase of $5.9 million.

	Three months ended September 30		Three months ended September 30	
	2011	**2010**	**2011**	**2010**
Number of				
Wastewater treated (millions of gallons)			**475**	475
Water sold (millions of gallons)			**1,800**	1,800
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Wastewater treatment	**$ 5,822**	$ 5,090	**$ 5,706**	$ 5,321
Water distribution	**6,511**	4,555	**6,382**	4,762
Other Revenue	**167**	137	**170**	165
	$ 12,500	$ 9,782	**$ 12,258**	$ 10,248
Expenses				
Operating expenses	**(5,895)**	(5,643)	**(5,789)**	(5,921)
Other income	**77**	55	**79**	57
Division operating profit	**$ 6,682**	$ 4,194	**$ 6,548**	$ 4,384

2011 Third Quarter Operating Results

During the quarter ended September 30, 2011, Liberty Utilities (South) provided approximately 1.8 billion U.S. gallons of water to its customers, treated approximately 475 million U.S. gallons of wastewater and sold approximately 110 million U.S. gallons of treated effluent.

For the quarter ended September 30, 2011, Liberty Utilities (South)'s revenue totalled U.S. $12.5 million as compared to U.S. $9.8 million during the same period in 2010, an increase of U.S. $2.7 million or 28%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state legislators over the past two years.

Revenue from wastewater treatment totalled U.S. $5.8 million, as compared to U.S. $5.1 million during the same period in 2010, an increase of U.S. $0.7 million or 14%. The third quarter wastewater treatment revenue increased primarily from the implementation of rate increases of U.S. $0.7 million at the LPSCo facility and U.S. $0.1 million at the Black Mountain facility as compared to the same period in 2010.

Revenue from water distribution totalled U.S. $6.5 million, as compared to U.S. $4.6 million during the same period in 2010, an increase of U.S. $2.0 million or 43%. The third quarter water distribution revenue increased primarily due to the implementation of rate increases of U.S. $1.5 million at the LPSCo facility, U.S. $0.2 million at the Rio Rico facility and U.S. $0.2 million at the Bella Vista facility as compared to the same period in 2010.

For the quarter ended September 30, 2011, operating expenses totalled U.S. $5.9 million, as compared to U.S. $5.6 million during the same period in 2010. Overall expenses increased U.S. $0.3 million or 4% as compared to the same period in 2010. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.1 million and U.S. $0.2 million related to wages, salary and other operating costs as compared to the same period in 2010.

For the quarter ended September 30, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $6.7 million as compared to U.S. $4.2 million in the same period in 2010, an increase of U.S. $2.5 million or 59%. Liberty Utilities (South)'s operating profit exceeded expectations for the three months ended September 30, 2011.

Measured in Canadian dollars, for the quarter ended September 30, 2011, Liberty Utilities (South)'s revenue totalled $12.3 million, as compared to $10.2 million during the same period in 2010. Revenue from wastewater treatment totalled $5.7 million, as compared to $5.3 million during the same period in 2010, an increase of $0.4 million. Revenue from water distribution totalled $6.4 million, as compared to $4.8 million in the same period in 2010, an increase of $1.6 million. Liberty Utilities (South) reported decreased revenue from operations of $0.7 million in the third quarter of 2011 as a result of the weaker U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the quarter ended September 30, 2011, operating expenses totalled $5.8 million, consistent with same period in 2010. Liberty Utilities (South) reported lower expenses from operations of $0.4 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the quarter ended September 30, 2011, Liberty Utilities (South)'s operating profit totalled $6.5 million as compared to $4.4 million in the same period in 2010, an increase of $2.2 million.

Outlook – Liberty Utilities (South)

Liberty Utilities (South) provides rate regulated utility services primarily in the southern and southwestern U.S. where communities have experienced periods of long-term growth and that management believes provides continuing future opportunities for organic growth. Liberty Utilities (South) expects continuing modest customer growth throughout its service territories in 2011.

Revenue increases from rate cases completed in Arizona and Texas are anticipated to contribute additional revenue in Liberty Utilities (South) in the fourth quarter of 2011 as compared to the same period in 2010. Liberty Utilities (South) attributes approximately U.S. $7.0 million of the revenue increases in the nine months ended September 30, 2011 to the impact of completed rate cases and anticipates that this will continue in the fourth quarter.

Liberty Utilites (West) (formerly Liberty Energy)

Liberty Utilities (West) operates in California and currently provides local electrical distribution utility services to approximately 47,000 customers located in the Lake Tahoe region.

	Nine months ended September 30 2011	2010	Nine months ended September 30 2011	2010
Number of Customer Accounts				
Residential			41,345	-
Commercial – Small			5,507	-
Commercial – Large			54	-
Total Customer Accounts			**46,906**	-
Customer Usage (MWhr)				
Residential			219,000	-
Commercial – Small			123,250	-
Commercial – Large			93,300	-
Total Customer Usage (MWhr)			**435,550**	-
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**139,596**	-		
Revenue				
Utility energy sales and distribution	**$ 57,324**	$ -	**$ 56,082**	$ -
Less:				
Cost of Sales – Energy*	**(33,740)**	-	**(33,005)**	
	$ 23,584	$ -	**$ 23,077**	$ -
Expenses				
Operating expenses	**(11,016)**	-	**(10,776)**	-
Division operating profit**	**$ 12,568**	$ -	**$ 12,301**	$ -

* Cost of Sales – Energy consists of energy purchases. Under GAAP, in APUC's Financial Statements, these amounts are included in operating expenses.

** Represents 100% of investment in the California Utility.

As at September 30, 2011, Liberty Utilities (West) holds a 50.001% controlling interest in the California Utility. As the California Utility was acquired on January 1, 2011 there are no comparable results for 2010.

Liberty Utilities reports active connections, exclusive of vacant connections rather than total connections. Liberty Utilities (West) had approximately 41,260 residential electrical customer accounts and 5,550 commercial electrical customer accounts, as at September 30, 2011.

2011 Nine Month Operating Results

During the nine months ended September 30, 2011, Liberty Utilities (West)'s customer usage totalled approximately 435,550 MWhr of energy.

For the nine months ended September 30, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $57.3 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are ultimately passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the nine months ended September 30, 2011, net utility energy sales revenue for Liberty Utilities (West) totalled U.S. $23.6 million.

For the nine months ended September 30, 2011, energy purchases for Liberty Utilities (West) totalled U.S $33.7 million. During the nine months, the California Utility purchased approximately 435,550 MWhr of energy at rates averaging U.S. $77.5 per MWhr.

For the nine months ended September 30, 2011, operating expenses, excluding energy purchases, totalled U.S. $11.0 million.

For the nine months ended September 30, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $12.6 million. Liberty Utilities (West)'s operating profit met expectations for the nine months ended September 30, 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $56.1 million. For the nine months ended September 30, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $23.1 million.

Measured in Canadian dollars, for the nine months ended September 30, 2011, Liberty Utilities (West)'s energy purchases totalled $33.0 million.

Measured in Canadian dollars, for the nine months ended September 30, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $10.8 million.

For the nine months ended September 30, 2011, Liberty Utilities (West)'s operating profit totalled $12.3 million.

	Three months ended September 30		Three months ended September 30	
	2011	**2010**	**2011**	**2010**
Customer Usage (MWhr)				
Residential			**58,700**	-
Commercial – Small			**39,400**	-
Commercial – Large			**25,200**	-
Total Customer Usage (MWhr)			**123,300**	-
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Utility energy sales and distribution	**$ 17,010**	$ -	**$ 16,663**	$ -
Less:				
Cost of Sales – Energy*	**(10,150)**	-	**(9,943)**	-
	$ 6,860	$ -	**$ 6,720**	$ -
Expenses				
Operating expenses	**(3,524)**	-	**(3,458)**	-
Division operating profit**	**$ 3,336**	$ -	**$ 3,262**	$ -

* Cost of Sales – Energy consists of energy purchases. Under GAAP, in APUC's Financial Statements, these amounts are included in operating expenses.

** Represents 100% of investment in the California Utility.

2011 Third Quarter Operating Results

For the quarter ended September 30, 2011, Liberty Utilities (West)'s customer usage totalled approximately 123,300 MWhr of energy.

For the quarter ended September 30, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $17.0 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the quarter ended September 30, 2011, Liberty Utilities (West)'s net utility energy sales revenue totalled U.S. $6.9 million.

For the quarter ended September 30, 2011, Liberty Utilities (West)'s energy purchases totalled U.S $10.2 million. During the quarter, the California Utility purchased approximately 136,800 MWhr of energy at rates averaging U.S. $82.3 per MWhr.

For the quarter ended September 30, 2011, Liberty Utilities (West)'s operating expenses, excluding energy purchases, totalled U.S. $3.5 million.

For the quarter ended September 30, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $3.3 million. Liberty Utilities (West)'s operating profit met expectations for the three months ended September 30, 2011.

Measured in Canadian dollars, for the quarter ended September 30, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $16.7 million. For the quarter ended September 30, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $6.7 million.

Measured in Canadian dollars, for the quarter ended September 30, 2011, Liberty Utilities (West)'s energy purchases totalled $9.9 million.

Measured in Canadian dollars, for the quarter ended September 30, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $3.5 million.

For the quarter ended September 30, 2011, Liberty Utilities (West)'s operating profit totalled $3.3.

Outlook – Liberty Utilities (West)

Liberty Utilities (West) expects modest customer growth within its service territories in 2011. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the fourth quarter of 2011.

On April 29, 2011, Liberty Utilities announced it had reached an agreement with Emera to acquire the interest in the California Utility held by Emera. Emera agreed to sell its 49.999% direct ownership in the California Utility, with closing of such transaction subject to regulatory approval. As consideration Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the California Utility ownership transfer (expected in early 2012) and the balance of the shares will be issued following completion of the California Utility's first rate case, expected to be completed in the latter half of 2012.

Liberty Utilities (East)

On December 9, 2010, Liberty Utilities (entered into agreements to acquire all issued and outstanding shares of Granite State, a rate regulated New Hampshire electric utility, and EnergyNorth, a rate regulated New Hampshire natural gas utility for a total purchase price of U.S. $285 million, plus working capital and subject to certain other closing adjustments. Granite State and EnergyNorth are anticipated to have regulatory assets at closing of approximately U.S. $72.0 million and U.S. $178.8 million, respectively. Upon completion of the transaction, the results of these utilities will be reported in the Liberty Utilities (East) division.

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire. Closings of the transactions are subject to certain conditions including state and federal regulatory approval, and are expected to occur in early 2012. Liberty Utilities is actively pursuing such approvals with the NHPUC. Following the preliminary hearing held the NHPUC on April 20, 2011, the parties reached agreement on a procedural schedule establishing final hearings, if necessary, for January 2012.

Financing of these acquisitions is expected to occur simultaneously with the closing of the transactions. Liberty Utilities (East) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

Liberty Utilities (Central)

On May 13, 2011, Liberty Utilities (Central) entered into an agreement with ATMOS Energy Corporation ("Atmos") to acquire the gas utilities located in Missouri, Iowa, and Illinois. Total purchase price for the gas utilities is approximately U.S. $124 million, plus working capital and subject to certain other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately $112 million, representing a purchase price multiple of 1.106x. The gas utilities currently provide natural gas local distribution service to approximately 84,000 customers (57,000 in Missouri, 23,000 in Illinois, and 4,000 in Iowa). Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in mid 2012. Upon completion of the transaction, the results of these utilities will be reported in the Liberty Utilities (Central) division. It is expected that management responsibility for the rate regulated water utility systems located in Missouri and currently reported in the results of Liberty Utilities (South) will be transferred to Liberty Utilities (Central) following the acquisition of the Atmos assets.

Financing of this acquisition is expected to occur simultaneously with the closing of the transaction. Liberty Utilities (Central) is targeting a capital structure of not more than 50% debt to total capitalization consistent with investment grade utilities.

APUC: Corporate

	Three months ended September 30 2011	Three months ended September 30 2010	Nine months ended September 30 2011	Nine months ended September 30 2010
Corporate and other expenses:				
Administrative expenses	**$ 4,754**	$ 3,855	**$ 12,686**	$ 9,760
Gain on foreign exchange	**(1,149)**	(840)	**(1,051)**	(474)
Interest expense	**7,429**	6,287	**22,870**	18,318
Interest, dividend and other Income	**(732)**	(937)	**(2,197)**	(2,614)
Loss on derivative financial instruments	**3,754**	805	**4,285**	2,945
Income tax recovery	**(16,465)**	(1,942)	**(16,434)**	(4,377)

2011 Nine Month Corporate and Other Expenses

During the nine months ended September 30, 2011, management and administrative expenses totalled $12.7 million, as compared to $9.8 million in the same period in 2010. The expense increase in the nine months ended September 30, 2011 primarily results from increased salaries and bonuses related to the management and administering APUC's operations, stock option expense, franchise taxes and other costs as compared to the same period in 2010.

For the nine months ended September 30, 2011, interest expense totalled $22.9 million as compared to $18.3 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s long term debt private placement compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures, as compared to the same period in 2010.

For the nine months ended September 30, 2011, interest, dividend and other income totalled $2.2 million, as compared to $2.6 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

Gain on derivative financial instruments consists of realized and unrealized mark-to-market losses on interest rate swaps and forward energy contracts during the first three quarters of 2011. The unrealized portion of any mark-to-market gains or losses on derivative instruments does not impact APUC's current cash position.

An income tax recovery of $16.4 million was recorded in the nine months ended September 30, 2011, as compared to a recovery of $4.4 million in the same period in 2010. There are two primary reasons for the income tax recovery for the period ended September 30, 2011. First, in the third quarter of 2011, APUC completed a capital structure project to ensure its operating subsidiaries have a capital structure that is appropriate for the business sector and that uses the functional currency in which it operates. Therefore as part of this process, APUC converted Canadian dollar denominated intercompany notes with Algonquin Power Fund America, a U.S. subsidiary of Algonquin Power Co, into U.S. dollar denominated preferred shares resulting in a realized foreign exchange loss for tax purposes, thereby creating a future tax asset of approximately $15.6 million that is now available as additional tax shelter in future years. Secondly, on October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. Included in future income tax recoveries for the nine months ended September 30, 2011 is $5.4 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2011 Third Quarter Corporate and Other Expenses

During the quarter ended September 30, 2011, management and administrative expenses totalled $4.8 million, as compared to $3.9 million in the same period in 2010. The expense increase in the three months ended September 30, 2011 primarily results from the reasons discussed in "Nine Month Corporate and Other Expenses" above as compared to the same period in 2010.

For the quarter ended September 30, 2011, interest expense totalled $7.4 million as compared to $6.3 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s long term debt private placement compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures, as compared to the same period in 2010.

For the quarter ended September 30, 2011, interest, dividend and other income totalled $0.7 million, as compared to $0.9 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

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

An income tax recovery of $16.5 million was recorded in the three months ended September 30, 2011, as compared to a recovery of $1.9 million in the same period a year ago. The income tax recovery for the three months ended September 30, 2011 results from those factors discussed "Nine Month Corporate and Other Expenses" above as compared to the same period in 2010. Included in future income tax recoveries for the three months ended September 30, 2011 is $1.9 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

Non-GAAP Performance Measures

Reconciliation of Adjusted 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. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense, income tax expense or recoveries, acquisition costs, interest expense, gain or loss on derivative financial instruments, earnings attributable to non-controlling interests and gain or loss on foreign exchange. APUC adjusts for these factors as they may be non-cash, non-recurring and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted 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 Unaudited Interim Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. 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**	
	2011	**2010**	**2011**	**2010**
Net earnings attributable to Shareholders	**$ 19,584**	$ 1,260	**$ 31,930**	$ 2,320
Add (deduct):				
Net earnings attributable to the non controlling interest	**819**	104	**3,466**	315
Income tax recovery	**(16,465)**	(1,942)	**(16,434)**	(4,377)
Interest expense	**7,429**	6,287	**22,870**	18,318
Acquisition Costs	**772**	332	**1,786**	684
Loss on derivative financial instruments	**3,754**	805	**4,285**	2,945
Gain on foreign exchange	**(1,149)**	(840)	**(1,051)**	(474)
Amortization	**11,074**	11,706	**34,095**	34,599
Adjusted EBITDA	**$ 25,818**	$ 17,712	**$ 80,947**	$ 54,330

For the nine months ended September 30, 2011, Adjusted EBITDA totalled $80.9 million as compared to $54.3 million, a net increase of $26.6 million or 49% as compared to the same period in 2010. For the quarter ended September 30, 2011, Adjusted EBITDA totalled $25.8 million as compared to $17.7 million, a net increase of $8.1 million or 46% as compared to the same period in 2010.

The major factors impacting Adjusted EBITDA are set out below. A more detailed analysis of these factors is presented within the business unit analysis.

		Three months ended September 30, 2011 (millions)		Nine months ended September 30, 2011 (millions)
Comparative Prior Period Adjusted EBITDA	$	17.7	$	54.3
Significant Changes:				
Acquisition of the California Utility		3.3		12.6
EFW facility		(0.1)		5.6
Liberty Utilities (South) revenue increases primarily due to rate case approvals		2.4		6.5
Hydro Renewable due to improved hydrology		3.0		6.6
St. Leon - primarily due to an increased wind resource		0.1		1.4
Administration and management costs		(0.9)		(2.9)
Lower results from the weaker U.S. dollar		(0.7)		(2.0)
Tinker Hydro / ESB primarily due to lower energy demand (improved hydrology in Q3)		1.0		(0.8)
Windsor Locks – change in operating model		(0.9)		(1.5)
Other		0.9		1.1
Current Period Adjusted EBITDA	**$**	**25.8**	**$**	**80.9**

Reconciliation of adjusted net earnings to net earnings

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 or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps, energy forward contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. APUC uses adjusted net earnings to assess the performance of APUC without the effects of gains or losses on derivatives and acquisition expenses as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of APUC'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 Interim Unaudited 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 APUC. 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 to adjusted net earnings exclusive of these items:

	Three months ended September 30 2011 (millions)	Three months ended September 30 2010 (millions)	Nine months ended September 30 2011 (millions)	Nine months ended September 30 2010 (millions)
Net earnings attributable to Shareholders	**$ 19.6**	$ 1.3	**$ 31.9**	$ 2.3
Add:				
Loss on derivative financial instruments, net of tax	**2.4**	0.5	**3.0**	2.0
Gain on foreign exchange, net of tax	**(1.1)**	(0.8)	**(1.1)**	(0.5)
Acquisition costs, net of tax	**0.5**	0.2	**1.1**	0.5
Adjusted net earnings	**$ 21.4**	$ 1.2	**$ 34.9**	$ 4.3
Adjusted net earnings per share	**$ 0.18**	$ 0.01	**$ 0.31**	$ 0.05

For the nine months ended September 30, 2011, adjusted net earnings totalled $34.9 million as compared to adjusted net earnings of $4.3 million, an increase of $30.6 million as compared to the same period in 2010. The increase in adjusted net earnings in the nine months ended September 30, 2011 is primarily due to increased earnings from operations, partially offset by increased interest and administrative expenses as compared to the same period in 2010.

For the three months ended September 30, 2011, adjusted net earnings totalled $21.4 million as compared to adjusted net earnings of $1.2 million, an increase of $20.2 million as compared to the same period in 2010. The increase in adjusted net earnings in the three months ended September 30, 2011 is primarily due to increased earnings from operations, partially offset by increased interest and administrative expenses as compared to the same period in 2010.

Summary of Property, Plant and Equipment Expenditures

APCo	Three months ended September 30 2011 (millions)		Three months ended September 30 2010 (millions)		Nine months ended September 30 2011 (millions)		Nine months ended September 30 2010 (millions)
Renewable Energy Division							
Capital expenditures	**$**	**16.9**	$	0.4	**$**	**18.9**	$	1.4
Acquisition of operating entities		**-**		-		**-**		40.3
Total	**$**	**16.9**	**$**	**0.4**	**$**	**18.9**	**$**	**41.7**
Thermal Energy Division								
Capital expenditures	**$**	**9.0**	$	1.2	**$**	**9.1**	$	11.1
LIBERTY UTILTITES								
South								
Capital Investment in regulatory assets	**$**	**1.2**	$	1.0	**$**	**6.3**	$	2.1
Acquisition of operating entities		**0.9**		-		**0.9**		2.1
Total	**$**	**2.1**	$	1.0	**$**	**7.2**	$	4.2
West								
Capital Investment in regulatory assets	**$**	**2.4**	$	-	**$**	**5.4**	$	-
Acquisition of operating entities		**(1.0)**		0.7		**97.3**		0.7
Total	**$**	**1.4**	$	0.7	**$**	**102.7**	$	0.7
Consolidated								
Total APCo								
Capital expenditures	**$**	**25.8**	$	1.6	**$**	**27.9**	$	12.5
Acquisition of operating entities		**-**		-		**-**	$	40.3
Total Liberty Utilities								
Capital Investment in regulatory assets		**3.7**	$	1.0	**$**	**11.7**	$	2.1
Acquisition of operating entities		**(0.1)**		0.7		**98.2**	$	2.8
Corporate		-		-		**0.3**		0.1
Total	**$**	**29.4**	$	3.3	**$**	**138.1**	$	57.7

APUC's consolidated capital expenditures in the nine months ended September 30, 2011 increased as compared to the same period in 2010 primarily due to the acquisition of the California Assets, the start of the construction of St. Leon II and the Windsor Locks repowering project.

Property, plant and equipment expenditures for the remainder of the 2011 fiscal year are anticipated to be approximately $10 million for ongoing operations, including approximately $3.0 million related to ongoing investments by Liberty Utilities, in water and wastewater utility infrastructure $1.5 million related to Liberty Utilities' share of ongoing investments at the California Utility, $5.0 million related to the APCo Thermal division and $1.5 million related to the APCo Renewable Energy division. In addition, the APCo Renewable Energy division expects to invest approximately $10 million related to the development of St. Leon II in the fourth quarter of 2011.

APUC anticipates that it can generate sufficient liquidity through internally generated operating cash flows, working capital and bank credit facilities to finance its property, plant and equipment expenditures and other commitments.

2011 Nine Month Property Plant and Equipment Expenditures

During the nine months ended September 30, 2011, APCo incurred net capital expenditures of $27.9 million, as compared to $12.5 million during the comparable period in 2010. APCo also invested $40.3 million to acquire operating assets/entities during the comparable period in 2010.

During the nine months ended September 30, 2011, APCo Renewable Energy division's capital expenditures were $18.9 million, as compared to $1.4 million in the comparable period in 2010. The St. Leon II development and the turbine overhaul project at the Tinker facility were the only individual projects in excess of $0.5 million initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets in 2010 relate to the Tinker Assets located in New Brunswick and Maine.

During the nine months ended September 30, 2011, APCo Thermal Energy division's net capital expenditures were $9.1 million, as compared to $11.1 million in the comparable period in 2010. The expenditures in the nine months primarily relates to the Windsor Locks repowering project and investments at the Sanger facility. In the comparable period, the capital expenditures primarily relate to the EFW facility where major capital maintenance was underway.

During the nine months ended September 30, 2011, Liberty Utilities invested $11.7 million in regulatory assets, as compared to $2.1 million during the comparable period in 2010. Liberty Utilities also invested $98.2 million to acquire operating assets/entities as compared to $2.8 million during the comparable period in 2010.

During the nine months ended September 30, 2011, Liberty Utilities (South) invested $6.3 million in regulatory assets, as compared to an investment of $2.1 million in the comparable period. Liberty Utilities (South) acquired a water and wastewater utility near Noel Missouri for approximately U.S. $0.9 million. In the comparable period in 2010, Liberty Utilities (South) acquired a water and wastewater utility near Galveston Texas for approximately $2.1 million.

During the nine months ended September 30, 2011, Liberty Utilities (West) invested $5.4 million into regulatory assets. Liberty Utilities (West) invested $97.3 million to acquire the California Utility on January 1, 2011.

2011 Third Quarter Property Plant and Equipment Expenditures

During the quarter ended September 30, 2011, APCo incurred net capital expenditures of $25.8 million, as compared to $1.6 million during the comparable period in 2010.

During the quarter ended September 30, 2011, APCo Renewable Energy division's capital expenditures were $16.9 million, as compared to $0.4 million in the comparable period in 2010. The St. Leon II development and the turbine overhaul project at the Tinker facility were the only individual projects in excess of $0.5 million initiated in the current period.

During the quarter ended September 30, 2011, APCo Thermal Energy division's net capital expenditures were $9.0 million, as compared to $1.2 million in the comparable period in 2010. The expenditures in the quarter primarily relates to the Windsor Locks repowering project and investments at the Sanger facility.

During the quarter ended September 30, 2011, Liberty Utilities invested $25.8 million, as compared to $1.6 million during the comparable period in 2010.

During the quarter ended September 30, 2011, Liberty Utilities (South) invested $1.2 million in regulatory assets, as compared to an investment of $1.0 million in the comparable period. Liberty Utilities (South) acquired a water and wastewater utility near Noel Missouri for approximately U.S. $0.9 million during the quarter.

During the quarter ended September 30, 2011, Liberty Utilities (West) invested $2.4 million in regulatory assets. During the quarter, Liberty Utilities (West) recorded an adjustment to the purchase price of the California Utility which reduced the purchase price by $1.0 million.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo'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. All eleven dam safety evaluations have now been completed. Out of these, nine remedial plans have been submitted to the Quebec government and two are undergoing options analysis by APCo. Eight remedial plans have been accepted by the Quebec government and one is still being reviewed.

APCo has spent approximately $1.3 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APCo currently estimates further capital expenditures of approximately $16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

	Total	**2011**	**2012**	**2013**	**2014**	**2015**
Estimated future Bill C-93 Capital Expenditures	**16,900**	100	5,500	5,500	3,000	2,800

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Mont-Laurier facilities.

- The remediation plan for the Mont Laurier facility has been accepted by the Quebec government. APCo has been performing engineering and permitting since 2010 and is presently waiting for a Certificate of Authorization from the Quebec government before being able to proceed with the work. APCo anticipates completing the on-site remediation work in 2012.
- In respect of the Donnacona facility, APCo has been investigating alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates, representing a potential reduction in the above estimated costs of approximately $1.8 million. APCo anticipates completing the engineering in early 2012 and performing the remedial work in 2012 and 2013.

- APCo is in the process of performing a more detailed condition assessment for the St. Alban facility before finalizing the remediation plan for this dam. APCo anticipates condition assessment, engineering, and regulatory review to be performed between 2011 and 2013, with remedial work in 2014 to 2015.
- APCo is presently reviewing options with respect to the Bellterre facility including the removal of several small dams that are not required for power generation. APCo has been corresponding with the Quebec government and other stakeholders about these options since 2007. APCo anticipates completion of any required work on these dams to be completed by 2015.
- The dam remediation work related to the Chute Ford will be completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013. No dam remediation work is required at the Arthurville, Hydraska, and Ste-Brigitte facilities.
- The dam remediation work related to the Rawdon facility was completed in Q3 of 2011.

In addition to the C-93 related dam remediation work, APCo has implemented a dam condition monitoring program at some of the above facilities, following recommendations specified in the dam safety reviews.

Liquidity and Capital Reserves

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at September 30, 2011 under the senior banking facility (the "Facility"):

	2011 Q3 (pro-forma)* (millions)	**2011 Q3 (actual) (millions)**	**2011 Q2 (millions)**	**2011 Q1 (millions)**	**2010 Q4 ** (millions)**	**2010 Q3 (millions)**
Committed and available Facility	$ 120.0	$ 120.0	$ 142.0	$ 142.0	$ 142.0	$ 163.4
Funds Drawn on Facility	-	(12.0)	(70.0)	(65.0)	(64.5)	(108.9)
Letters of Credit issued	(40.1)	(40.1)	(32.5)	(32.9)	(33.1)	(33.8)
Remaining available Facility	**$ 79.9**	**$ 67.9**	**$ 39.5**	**$ 44.1**	**$ 44.4**	**$ 20.7**
Cash on Hand	95.0	15.5	8.7	2.5	5.1	3.1
Total liquidity and capital reserves	**$ 174.9**	**$ 83.4**	**$ 48.2**	**$ 46.6**	**$ 49.5**	**$ 23.8**

* Reflects the balances as at September 30, 2011, adjusted for the proceeds from the Offering and the exercise of the over-allotment option completed on October 27, 2011 and November 14, 2011. A portion of the proceeds of the Offering were used to repay the outstanding balance on the Facility.

** Reflects availability as at December 31, 2010, under the terms of a three year Facility renewed subsequent to December 31, 2010, having a maturity of February 14, 2014.

As at and for the period ended September 30, 2011, APCo was in compliance with the covenants under the Facility. As at September 30, 2011, $12.0 million had been drawn on the Facility as compared to $64.5 million as at December 31, 2010. In addition to amounts actually drawn, there were $40.1 million in letters of credit outstanding as at September 30, 2011. Amounts drawn on the Facility were repaid out of proceeds from APUC's equity offering (see below).

On July 25, 2011, APCo completed the Senior Unsecured Debenture offering of $135 million, the net proceeds of which have been used to repay the Airsource senior debt financing having a principal amount outstanding of $67.8 million with the balance being used to reduce amounts outstanding on the Facility. On the same day, the available Facility was reduced to $120 million.

On October 27, 2011, APUC completed an equity offering of $85.3 million, a portion of the net proceeds of which have been used to repay the outstanding balance on the Facility. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million. Therefore, after adjusting for the proceeds of the Offering, APUC had $79.9 million of committed and available bank facilities remaining and approximately $95.0 million of cash resulting in total liquidity and capital reserves of $174.9 million.

Contractual Obligations

Information concerning contractual obligations as of September 30, 2011 is shown below:

	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
	(millions)	(millions)	(millions)	(millions)	(millions)
Long-term debt obligations[1]	$ 349.8	$ 1.3	$ 3.5	$ 16.2	$ 328.8
Convertible Debentures	$ 122.5	-	-	-	122.5
Interest on long-term debt obligations	$ 275.1	29.7	57.6	54.2	133.6
Long Term Service Agreements	$ 93.9	3.2	8.1	8.5	74.1
Purchase obligations	$ 53.2	53.2	-	-	-
Capital Projects	$ 29.6	29.6	-	-	-
Derivative financial instruments:					
Interest rate swap	$ 7.6	2.5	3.8	1.3	-
Lease obligations	$ 2.9	1.2	1.3	0.4	-
Other obligations	$ 10.4	1.2	0.5	0.5	8.2
Total obligations	$ 945.0	$ 121.9	$ 74.8	$ 81.1	$ 667.2

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

SHAREHOLDERS' EQUITY AND CONVERTIBLE DEBENTURES

APUC's shares are publicly traded on the Toronto Stock Exchange ("TSX"). As at September 30, 2011, APUC had 119,214,224 issued and outstanding shares. On October 27, 2011, APUC issued 15,100,000 common shares. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. Following the Offering and exercise of the over-allotment option, APUC had 136,086,224 issued and outstanding shares.

As at September 30, 2011, APUC had issued to Emera a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the Granite State and EnergyNorth transactions at a purchase price of $5.00. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost to acquire Granite State and EnergyNorth.

On April 29, 2011, APUC agreed to issue to Emera 8.2 million shares with regards to the acquisition by Liberty Utilities of Emera's 49.999% direct ownership in the California Utility. The approval on the ownership transfer is expected in late 2011. The payment of shares is to be made in two tranches with approximately half of the shares being issued following regulatory approval of the ownership transfer and the balance of the shares being issued following completion of the California Utility's first rate case which is expected to be completed in 2012.

On April 30, 2011, APUC committed to issuance to Emera of a treasury subscription of subscription receipts convertible into approximately 6.9 million APUC common shares upon closing of the transaction related to the acquisition of an interest in a portfolio of 370MW wind projects (see Major Highlights - Acquisition of First Wind's Northeast Projects for more details on the acquisition) at a purchase price of $5.37 per subscription receipt. Total gross proceeds to APUC of $37 million will be utilized to fund a portion of the cost to acquire the interest in Northeast Wind.

APUC may issue an unlimited number of common shares. The holders of common shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of common shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

The Series 1A Debentures previously due November 30, 2014 were redeemed on the Redemption Date. Between April 1, 2011 and the Redemption Date, a principal amount of $60,266 of Series 1A Debentures were converted into 14,771,185 shares of APUC.

On May 16, 2011 the redemption was effected in accordance with the terms and definitions of the trust indenture governing the Debentures. APUC satisfied its obligation to pay the remaining holders of Debentures ("Debentureholders") by issuing and delivering 430,666 APUC shares, which represented the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of APUC shares on the Redemption Date. Unpaid accrued interest on the Debentures in the amount of $59 was paid in cash at the time of redemption. On September 30, 2011, as a result of the Redemption there were nil Series 1A Debentures outstanding.

The convertible unsecured subordinated debentures bearing interest at 6.35%, maturing on November 30, 2016 ("Series 2A Debentures") pay interest semi-annually in arrears on April 1 and October 1 each year and are convertible into shares of APUC at the option of the holder at a conversion price of $6.00 per share. On September 30, 2011, there were 59,967 Series 2A Debentures outstanding with a face value of $59,967.

The convertible unsecured debentures maturing on June 30, 2017 ("Series 3 Debentures") bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into shares of APUC at the option of the holder at a conversion price of $4.20 per share.

During the nine months ended September 30, 2011, a principal amount of $205 of Series 3 Debentures was converted into 48,807 APUC shares. During the three months ended September 30, 2011, a principal amount of $60 of Series 3 Debentures was converted into 14,284 APUC shares. On September 30, 2011, there were 62,700 Series 3 Debentures outstanding with a face value of $62,700. Subsequent to the end of the quarter, $15 Series 3 Debentures were converted to 3,571 APUC shares.

SHARE BASED COMPENSATION PLANS

STOCK OPTION PLAN

On June 23, 2010, APUC's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. On June 21, 2011, APUC's shareholders approved amendments to the Plan to limit non-employee director participation in the Plan and to require shareholder approval to make further amendments to the plan with respect to a number of items as more fully described in the management information circular for the 2011 annual and special meeting of shareholders.

During the year ended December 31, 2010, 1,160,204 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $4.05. One-third of the options vest on each of January 1, 2011, 2012 and 2013. During the nine months ended September 30, 2011, the Board approved the following grant of options:

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;
- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.68.

All options are issued at the market price of the underlying common share at the date of grant. In each case, one-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

During the nine months ended September 30, 2011, no options were exercised. As at September 30, 2011, APUC had 2,428,941 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

For the three and nine month period ended September 30, 2011, APUC recorded, respectively $228 and $445 (2010 - $34 and $34), in compensation expense. As at September 30, 2011, there was $1,460 of total unrecognized compensation costs related to stock options granted under the Plan. The cost is expected to be recognized over a period of 2.0 years.

As at September 30, 2011, 386,735 options with an intrinsic value of $657 are exercisable. No share options were exercised in 2011 or 2010. The intrinsic value of the 2,487,104 options as at September 30, 2011 was $2,468.

PERFORMANCE SHARE UNITS

In October 2011, APUC issued 28,370 performance share units ("PSUs") to certain members of management other than senior executives as part of APUC's long-term incentive program. At the end of the three-year performance periods, the number of shares vested can range from 0% to 144% of the number of PSUs granted. Dividends accumulate during vesting period and are converted to PSUs based on the market value of the shares on that date. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As APUC does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

DIRECTORS DEFERRED SHARE UNITS

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one APUC common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period. As at September 30, 2011, no DSUs had been issued.

EMPLOYEE SHARE PURCHASE PLAN

In September 2011, APUC approved an employee share purchase plan ("ESPP"). Eligible employees may have a portion of their earnings withheld to be used to purchase common shares of APUC. APUC will match up to 20% of employee contribution amount for the first $5,000 contributed annually and 10% of employee contribution amount for contributions over $5,000 and up to $10,000 annually. Shares purchased through the APUC match portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at September 30, 2011, no ESPPs had been issued.

DIVIDEND REINVESTMENT PLAN

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the "Reinvestment Plan") which will be offered to registered holders of shares ("Shareholders") of APUC.

The purpose of the Reinvestment Plan is to enable Shareholders to invest all cash dividends on Shares in additional shares of APUC ("Plan Shares"). All such Plan Shares will be, at APUC's election, either (i) Shares purchased on the open market through the facilities of the TSX ("Market Purchase") or (ii) newly issued Shares purchased from APUC ("Treasury Purchase").

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the Agent for all Plan Shares purchased in respect of a Dividend Payment Date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Shares of APUC on TSX for the five (5) trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC's election. No commissions, service charges or brokerage fees are payable by Shareholders in connection with the Reinvestment Plan.

RELATED PARTY TRANSACTIONS

- Certain executives of APUC and members of the Board are shareholders of Algonquin Power Management Inc. ("APMI"), the former manager of APCo. A member of the Board is an executive at Emera.

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three months and nine months ended September 30, 2011 were $82 and $245 (2010 $82 and $245). Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.

- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the three and nine months ended September 30, 2011, APUC incurred costs in connection with the use of the aircraft of $226 and $350 (2010 $162 and $370) and amortization expense related to the advance against expense reimbursements of $77 and $205 (2010 - $36 and $99). At September 30, 2011, the remaining amount of the advance was $349 (2010 - $460) and is recorded in other assets.

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. 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 June 17, 2008 growing to a maximum of 10% by year 15. 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 related holders of the Class B units have received cash distributions of $121 and $208 for the three and nine months ended September 30, 2011 (2010 - $63 and $189).

- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the nine months ended September 30, 2011, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount is included in accrued liabilities at September 30, 2011.

- Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by a non-APUC entity. APUC has agreed to provide some transition services until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit.

- The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions. As at September 30, 2011 amount due from the above related party transactions was $2,181 (December 31, 2010 - $718) and amounts due to related parties was $1,661 (December 31, 2010 - $901).

- A contract with a subsidiary of Emera to purchase energy on ISO NE and provide scheduling services on ISO NE was included as part of the acquisition of the ESB associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the ESB. In this capacity, for the three and nine months ended September 30, 2011 APUC paid a subsidiary of Emera an amount of $0 (2010 - $1,368) which was included as an operating expense on the consolidated statement of operations.

- In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks Facility. During the three and nine months ended September 30, 2011 APUC paid U.S. $84 and $187 (2010 - $71 and $132) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

- On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). For the three and nine months ended September 30, 2011, the ESB sold electricity of $1,659 and $5,301 to MPS. In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

- As of September 30, 2011, included in amounts due from related parties is $1,672 (2010 - $0) owed from Emera related to the unpaid contribution of their share of Liberty Utilities (West) costs. APUC believes that the transactions with Emera noted above were in accordance with normal commercial terms. The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.
- In May 2011, APUC received $339 from CJIG Management Inc. ("CJIG"), as its share of 50% of the additional proceeds received by CJIG from the further liquidation of the assets held by Highground Capital Corporation. This has been recorded as an increased amount assigned to the equity originally issued in connection with the Highground transaction. In August 2011 the Company received an additional $734 from CJIG. The payments have been recorded as an increased amount assigned to the equity originally issued in connection with the Highground transaction.

Business Associations with APMI and Senior Executives

There are a number of continuing business relationships between APUC and one of Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. The Board has initiated a process to review all of the remaining business associations with Senior Executives, APMI and related affiliates in order to reduce, streamline and simplify these relationships. Any transaction associated with this process will only proceed if they are expected to be accretive to APUC.

The Board has formed a special committee and has engaged independent consultants to assist with this process and expects to conclude this process by the end of 2011.

The co-owned assets and remaining business associations consist of the following:

i) *Rattlebrook hydroelectric generating facility*
Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC and 27.5% by Senior Executives and the remaining percentage by third parties.

ii) *St. Leon wind power generating facility*
St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives.

iii) *Brampton Cogeneration Inc.*
BCI is an energy supply facility which sells steam produced from APCo's EFW facility. APMI maintains a carried interest equal to 50% of the annual returns on the project greater than 15%. No amounts have ever been paid under this carried interest. In 2008, APMI earned a construction supervision fee of $100 in relation to the development of this project. In 2008, APUC accrued $100 as an estimate of the final fee owed to APMI.

iv) *Long Sault Rapids hydroelectric generating facility*
Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the equity cash flows commencing in 2014.

v) *Chartered aircraft*

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At September 30, 2011, $349 of the advance remained. The Board has undertaken an independent review of the relationship and believes that continuing the original arrangement is beneficial to the company. The current arrangement is expected to end in approximately 2016 when the capital advance will be repaid.

vi) *Office lease*

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The original lease was due to expire in December 31, 2012. Effective April 1, 2011, a subsidiary of APUC leased its head office facilities from a third party in a new stand alone building immediately adjacent to APUC's head office for a term of 5 years ending December 31, 2015 with an additional 5 year renewal option. APUC has amended its lease at its existing premises to be co-terminus with its subsidiary's new lease. The majority of terms in the amended lease are identical. Based on a review of the real estate leasing market in the fall of 2010, APUC believes the amended lease is on terms equivalent to fair market value for prime office space of similar size and quality.

vii) *Operations services*

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") which is a non-APUC entity. APUC and APS have agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit.

viii) *Sanger construction management*

As part of the project to re-power the Sanger facility, APUC entered into an agreement with APMI to undertake certain construction management services on the project for a performance based contingency fee. In 2008, APUC accrued U.S. $0.6 million as an estimate of the final fee owed to APMI.

ix) *Clean Power Income Fund*

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of September 30, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet.

x) *Red Lily I*

APMI was an early developer of the 26 MW Red Lily I wind power generation facility. As such it is entitled to a royalty fee based on a percentage of operating revenue and a development fee from Red Lily I. APUC has acquired APMI's interest in these royalties for an amount of $0.6 million. APMI is also entitled to a development fee of up to $0.4 million following commercial operation of the project and has agreed to permit the Board to determine whether it will retain this fee following commercial operation of the facility.

xi) Trafalgar

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, Algonquin moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar was previously awarded a U.S. $10.0 million claim in respect of a lawsuit related to faulty engineering in the design of these facilities, and these funds are held in the bankruptcy estate. As previously disclosed, Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. APMI funded the initial $2 million in legal fees. An agreement was reached in 2004 between APMI and APUC whereby APUC would reimburse APMI 50% of the legal costs to date in an amount of approximately $1 million, and going forward APUC would fund the legal fees, third party costs and other liabilities with the proceeds from the lawsuits being shared after reimbursement of legal fees, third party costs and other liabilities. The Board has determined that any proceeds from the lawsuit will be shared between APMI and APUC proportionally to the quantum of such costs funded by each party. The Second Circuit Court of Appeals recently dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. The bankruptcy proceedings are continuing.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. APUC ensures that both APCo and Liberty Utilities maintain insurance on all of their facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies including currency and interest rate hedging policies to manage its risk exposures.

There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the U.S. versus Canadian dollar exchange rates, energy market prices, any credit risk associated with a reliance on key customers, interest rate, liquidity and commodity price risk considerations. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. A further assessment of APUC and its subsidiaries' business risks is also set out in the most recent AIF.

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 55% of EBITDA in 2011 and 65% of cash flow from operations is generated in U.S. dollars. APUC 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 $19.2 million and increased reported expenses from U.S. operations of approximately $13.1 million or a net impact of $6.1 million ($0.05 per share) on an annual basis.

The change in mark-to-market losses/(gains) on derivative financial instruments results from changes in interest rates or forward energy prices and relate to long term contract periods which extend to fiscal 2015. The following chart provides a summary of the nine month changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Nine months ended September 30		
	2011	**2010**	**Change**
Foreign Exchange Contracts:			
Change in unrealized mark-to-market loss/(gain) on derivative financial instruments	**$ (45)**	$ (727)	**$ 682**
Realized loss/(gain) on derivative financial instruments	**691**	(592)	**$ 1,283**
	$ 646	$ (1,319)	**$ 1,965**
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market loss/(gain) on derivative financial instruments	**$ 2,004**	$ (454)	**$ 2,458**
Realized loss on derivative financial instruments	**1,607**	4,635	**$ (3,028)**
	$ 3,611	$ 4,181	**$ (570)**
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ (429)**	$ (2,448)	**$ 2,019**
Realized loss on derivative financial instruments	**457**	2,531	**(2,074)**
	$ 28	$ 83	**$ (55)**
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ 1,530**	$ (3,629)	**$ 5,159**
Realized loss on derivative financial instruments	**2,755**	6,574	**(3,819)**
Total loss/(gain) on derivative financial instruments	**$ 4,285**	$ 2,945	**$ 1,340**

The following chart provides a summary of the quarter over quarter changes between realized and unrealized mark-to-market gains and losses of derivative financial instruments:

	Three months ended September 30		
	2011	**2010**	**Change**
Foreign Exchange Contracts:			
Change in unrealized mark-to-market loss on derivative financial instruments	**$ -**	$ (870)	**$ 870**
Realized gain on derivative financial instruments	**-**	(167)	**167**
	$ -	$ (1,037)	**$ 1,037**
Interest Rate Swap Contracts:			
Change in unrealized mark-to-market loss on derivative financial instruments	**$ 2,112**	$ 345	**$ 1,767**
Realized loss on derivative financial instruments	**539**	1,453	**$ (914)**
	$ 2,651	$ 1,798	**$ 853**

	Three months ended September 30 2011	2010	Change
Energy Forward Purchase Contracts:			
Change in unrealized mark-to-market gain on derivative financial instruments	**$ 974**	$ (534)	**$ 1,508**
Realized loss on derivative financial instruments	**129**	1,453	**$ (1,324)**
	$ 1,103	$ 919	**$ 184**
Derivative Financial Instruments Total:			
Change in unrealized mark-to-market loss on derivative financial instruments	**$ 3,086**	$ (1,059)	**$ 4,145**
Realized loss on derivative financial instruments	**668**	1,864	**(1,196)**
Total loss/(gain) on derivative financial instruments	**$ 3,754**	$ 805	**$ 2,949**

Interest rate risk

APCo 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:

- The banking credit facility provided to APCo by a consortium of Canadian chartered banks has an outstanding balance drawn of $12.0 million as at September 30, 2011. The outstanding balance was repaid subsequent to September 30, 2011 using part of the proceeds from the APUC equity offering. Assuming the adjusted level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would not impact interest expense.
- APCo's project debt at the St. Leon facility had a balance of $67.8 million as at June 30, 2011. The outstanding balance was repaid during the quarter ended September 30, 2011 using proceeds from the Senior Unsecured Debenture offering. Accordingly there is no further interest rate risk associated with this debt facility.
- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at September 30, 2011. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.

Liberty Utilities (South)'s project debt at the Litchfield and Bella Vista Facilities are subject to a fixed rate of interest and thus are not subject to interest rate risk. Liberty Utilities (South)'s U.S. $50 million senior unsecured notes with a 10 year term bearing a fixed rate of interest at 5.6% are subject to a fixed rate of interest and are not subject to interest rate risk.

Liberty Utilities (West)'s U.S. $70 million senior unsecured private debt placement at the California Utility is split into two tranches, U.S. $45 million of ten year 5.19% notes and U.S. $25 million of 5.59% fifteen year notes. As such these notes are not subject to interest rate risk.

Liquidity risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due. APUC'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.

APUC currently pays a dividend of $0.28 per share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensure APUC's long-term success. Based on the level of dividends paid during the nine months ended September 30, 2011, cash provided by operating activities exceeded dividends declared by 3.1 times.

As at September 30, 2011, after adjusting for the net proceeds of the Offering and exercise of the over-allotment option, APUC had cash on hand of $95.0 million and $79.9 million available to be drawn on the Facility. APUC reduced its level of short-term borrowings through the renewal of the Facility on February 14, 2011 for a three year term and through a U.S. $50 million private placement debt financing at Utility (South) on December 22, 2010. On July 25, APCo completed a private placement offering of the Senior Unsecured Debentures with a principal amount of $135 million. Net proceeds from the debentures were used to repay the project debt on APCo's AirSource senior debt financing which would have matured on October 2011, and to reduce amounts outstanding under APCo's senior credit facility. See the Liquidity and Capital Reserves section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facility.

The long term portion of Facility and project specific debt total approximately $348.5 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment into the company may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard 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 APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. See APUC's audited consolidated financial statements for the years ended December 31, 2010 and 2009 for discussion of this risk.

Liberty Utilities is exposed to energy price risk in its Liberty Utilities (West) region which is mitigated through the certain regulatory constructs. Liberty Utilities (West) provides electric service to the Lake Tahoe basin and surrounding areas at rates approved by the CPUC. The utility purchases the energy requirements for its customers from NV Energy at rates reflecting NV Energy's system average costs. In the event that these rates change, each $10.00 change per MWhr would result in a change in expense of approximately U.S. $6.5 million on an annualized basis.

The rate structure in California allows for a pass-through of energy costs to rate payers on a dollar for dollar basis, through the energy cost adjustment clause ("ECAC") mechanism, which is designed to recoup power supply costs that are caused by the fluctuations in the price of fuel and purchased power. Actual power supply costs incurred by the facility are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows for an adjustment to the California Utility's approved rates (including carrying charges associated therewith), substantially eliminating the commodity risk associated with the purchase of power.

OPERATIONAL RISK MANAGEMENT

APUC attempts to proactively manage its risk exposures in a prudent manner and has initiated a number of programs and policies such as employee health and safety programs and environmental safety programs to manage its risk exposures.

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, 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 APUC and its subsidiaries may encounter. A more detailed assessment of APUC's business risks is also set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC'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 Liberty 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. The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

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

Regulatory Risk

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

Liberty Utilities' facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. Federal, State and local environmental laws and regulations impose substantial compliance requirements on electricity and natural gas distribution utilities. Operating costs could be significantly affected in order to comply with new or stricter regulatory requirements.

Electricity and natural gas distribution 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 Liberty Utilities, and while Liberty Utilities 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.

Liberty Utilities regularly works with its governing authorities to manage the affairs of the business.

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their 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.

Liberty Utilities' 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, Liberty Utilities 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 distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its Financial Statements.

Environmental Risks

APUC and its subsidiaries face 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.

Liberty Utilities faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, Liberty Utilities generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, Liberty Utilities investigates promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

APUC'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, 2011.

Cycles and Seasonality

For Liberty Utilities (West), demand for energy is primarily affected by weather conditions and conservation initiatives. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Liberty Utilities (West) provides information and programs to its customers to encourage the conservation of energy. In turn, demand may be reduced which could have short term adverse impacts to revenues.

Disclosure Controls

At the end of the fiscal year ended December 31, 2010, APUC carried out an evaluation, under the supervision of and with the participation of the APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of the Company's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of December 31, 2010, APUC's disclosure controls and procedures are effective.

Internal controls over financial reporting

Management, including the CEO and the CFO, is responsible for establishing and maintaining internal control over financial reporting as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings. Management, as at the end of the period covered by this interim filing, designed internal control over financial reporting to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. The control framework management used to design the issuer's internal control over financial reporting is that established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Changes in internal controls over financial reporting

During the nine months ended September 30, 2011, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC's transition to U.S. GAAP in the period did not result in any significant changes to the APUC's internal controls.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended September 30, 2011.

Millions of dollars (except per share amounts)	4th Quarter 2010*	1st Quarter 2011	2nd Quarter 2011	3rd Quarter 2011
Revenue	$ 48.9	$ 71.7	$ 66.8	$ 66.0
Net earnings attributable to Shareholders	16.9	5.0	7.3	19.6
Basic net earnings per share	0.18	0.05	0.07	0.16
Total Assets	980.9	1,175.8	1,177.7	1,263.1
Long term debt**	461.0	461.0	530.0	558.9
Dividend per share	0.06	0.065	0.065	0.07
	4th Quarter 2009*	**1st Quarter 2010***	**2nd Quarter 2010***	**3rd Quarter 2010***
Revenue	$ 43.4	$ 45.9	$ 42.7	$ 45.4
Net earnings / (loss) attributable to Shareholders/Unitholders	(1.4)	3.5	(2.2)	1.5
Basic net earnings / (loss) per share/trust unit	(0.03)	0.04	(0.02)	0.02
Total Assets	1,013.4	966.2	983.2	969.4
Long term debt**	439.9	434.0	446.7	452.8
Dividends/distribution per share/trust unit	0.06	0.06	0.06	0.06

* Based on Canadian Generally Accepted Accounting Principals

** Long term debt includes long term liabilities, the Facility, 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 $42.7 million and $71.7 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the significant fluctuation in the strength of the Canadian dollar which has resulted in significant changes in reported revenue from U.S. operations.

Quarterly net earnings have fluctuated between net earnings of $19.6 million and a net loss of $2.2 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as future tax expense due to the enactment of Bill C-52 and mark-to-market gains and losses on financial instruments.

Critical Accounting Estimates

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

Additional disclosure of APUC's critical accounting estimates is also available in APUC's MD&A for the year ended December 31, 2010 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Changes in Accounting Policies

APUC's accounting policies are described in Note 1 to the Financial Statements for the period ended September 30, 2011.

Accounting framework

The Financial Statements and accompanying notes have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and follow disclosures required per Regulation S-X Rule 10-10, Interim Financial Statements provided by the Securities and Exchange Commission (SEC) Guidance. These are APUC's U.S. GAAP consolidated interim financial statements for part of the period covered by the first U.S. GAAP annual financial statements.

APUC's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the audited annual financial statements for the year ended December 31, 2010. Descriptions of the effect of the transition from Canadian GAAP to U.S. GAAP on the Company's financial position, financial performance and cash flows as at and for the two years ended December 31, 2010 are provided in note 24 of the audited consolidated financial statements for the year ended December 31, 2010. The accounting policies set out in the Interim Consolidated Financial Statements for the period ended September 30, 2011 have been consistently applied to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

There was no significant impact of the transition to U.S. GAAP on APUC's internal controls, information technology systems and financial reporting expertise requirements. No financial covenants were impacted by APUC's conversion to U.S. GAAP given the few differences that exist with Canadian GAAP.

Interim Consolidated Balance Sheets

(Unaudited)

(thousands of Canadian dollars)

	September 30, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash	$ 15,525	$ 4,749
Short term investments (note 1(e))	5,025	3,674
Accounts receivable net of allowance of $548 and $380	33,174	25,876
Due from related parties (note 13)	2,181	718
Prepaid expenses	4,874	3,547
Supplies and consumables inventory	2,716	-
Current portion of deferred tax asset	13,066	14,015
Current portion of notes receivable	469	1,172
	77,030	53,751
Long-term investments and notes receivable (note 4)	40,903	37,179
Deferred non-current income tax asset	91,336	74,997
Property, plant and equipment (note 5)	951,593	761,739
Intangible assets (note 6)	71,151	73,886
Goodwill (note 3)	12,082	994
Restricted cash (note 1(f))	3,550	3,563
Deferred financing costs	8,434	5,933
Derivative assets (note 20)	296	-
Regulatory assets (note 7)	4,858	2,484
Other assets	1,901	3,354
	$ 1,263,134	$ 1,017,880

Interim Consolidated Balance Sheets (continued):

(Unaudited)

(thousands of Canadian dollars)

	September 30, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	**$ 4,146**	$ 2,875
Accrued liabilities	**47,420**	28,839
Due to related parties (note 13)	**1,661**	1,534
Dividends payable	**8,341**	5,721
Current portion of long-term liabilities	**1,304**	70,432
Current portion of other long-term liabilities	**1,849**	1,011
Current portion of derivative instruments (note 20)	**2,480**	2,338
Current income tax liability	**810**	200
Current portion of deferred credit	**10,011**	11,020
Deferred income tax liability	**567**	514
	78,589	124,484
Long-term liabilities (note 8)	**348,490**	189,465
Convertible debentures (note 9)	**122,427**	181,760
Other long-term liabilities (note 10)	**88,001**	65,929
Other regulatory liabilities (note 7)	**19,981**	-
Deferred non-current income tax liability	**84,585**	81,941
Derivative instruments (note 20)	**5,170**	3,525
Deferred credits	**27,808**	32,222
Shareholders' equity (note 12):		
Shareholders' capital	**885,178**	796,941
Deficit	**(349,468)**	(358,542)
Accumulated other comprehensive loss	**(87,017)**	(99,845)
Total Equity attributable to APUC	**448,693**	338,554
Non-controlling interest (note 3(a))	**39,390**	-
Total stockholders' equity	**488,083**	338,554
Commitments and contingencies (note 14)		
Subsequent events (notes 12, 14 and 21)		
	$ 1,263,134	$ 1,017,880

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statements of Operations

(Unaudited)

(thousands of Canadian dollars, except per share amounts)

	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Revenue:				
Energy sales	**$ 31,952**	$ 29,766	**$ 99,833**	$ 96,604
Utility energy sales and distribution	**16,663**	-	**56,082**	-
Waste disposal fees	**4,074**	3,868	**12,360**	4,875
Water reclamation and distribution	**12,257**	10,249	**33,523**	28,002
Other revenue	**1,102**	916	**2,785**	2,457
	66,048	44,799	**204,583**	131,938
Expenses				
Operating	**36,882**	24,475	**115,010**	71,699
Amortization of property, plant and equipment	**9,547**	9,083	**29,205**	27,080
Amortization of intangible assets	**1,527**	2,623	**4,890**	7,519
Administrative expenses	**4,754**	3,855	**12,686**	9,760
Gain on foreign exchange	**(1,149)**	(840)	**(1,051)**	(474)
	51,561	39,196	**160,740**	115,584
Earnings before undernoted	**14,487**	5,603	**43,843**	16,354
Interest expense	**7,429**	6,287	**22,870**	18,318
Interest, dividend income and other income	**(1,406)**	(1,243)	**(4,060)**	(3,851)
Acquisition costs	**772**	332	**1,786**	684
Loss on derivative financial instruments (note 20 (c))	**3,754**	805	**4,285**	2,945
	10,549	6,181	**24,881**	18,096
Earnings (loss) from operations before income taxes	**3,938**	(578)	**18,962**	(1,742)
Income tax expense (recovery) (note 18)				
Current	**223**	219	**868**	655
Deferred	**(16,688)**	(2,161)	**(17,302)**	(5,032)
	(16,465)	(1,942)	**(16,434)**	(4,377)
Net earnings	**20,403**	1,364	**35,396**	2,635
Net earnings attributable to non controlling interests	**819**	104	**3,466**	315
Net earnings attributable to Algonquin Power & Utilities Corp.	**$ 19,584**	$ 1,260	**$ 31,930**	$ 2,320
Basic net earnings per share (note 17)	**$ 0.16**	$ 0.01	**$ 0.29**	$ 0.02
Diluted net earnings per share (note 17)	**$ 0.16**	$ 0.01	**$ 0.28**	$ 0.02

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statements of Cash Flows

(Unaudited)

(thousands of Canadian dollars)

	Three months ended Sept. 30, 2011	Three months ended Sept. 30, 2010	Nine months ended Sept. 30, 2011	Nine months ended Sept. 30, 2010
Cash provided by (used in):				
Operating Activities:				
Net earnings	**$ 20,403**	$ 1,364	**$ 35,396**	$ 2,635
Items not affecting cash:				
Amortization of property, plant and equipment	**9,547**	9,083	**29,205**	27,080
Amortization of intangible assets	**1,527**	2,623	**4,890**	7,519
Other amortization	**558**	567	**1,636**	1,548
Deferred taxes	**(16,688)**	(2,161)	**(17,302)**	(5,032)
Unrealized loss (gain) on derivative financial instruments	**3,074**	(1,058)	**1,518**	(3,629)
Stock option expense	**228**	34	**445**	34
Unrealized foreign exchange loss (gain)	**612**	(1,046)	**(81)**	(831)
Changes in non-cash operating working capital (note 16)	**10,543**	(4,152)	**9,377**	(3,036)
	29,804	5,254	**65,084**	26,288
Financing Activities:				
Cash dividends (note 15)	**(7,748)**	(5,703)	**(20,236)**	(13,192)
Cash distributions to non-controlling interest (note 13)	**(105)**	(107)	**(346)**	(318)
Issuance of common shares	**-**	-	**27,700**	-
Deferred financing costs	**(1,453)**	(62)	**(2,876)**	(153)
Increase in long-term liabilities	**134,768**	13,497	**203,019**	67,997
Decrease in long-term liabilities	**(127,762)**	(7,505)	**(122,615)**	(55,120)
Increase in other regulatory liabilities	**65**	-	**2,007**	-
Increase (decrease) in other long-term liabilities	**2,405**	(557)	**4,989**	(347)
	170	(437)	**91,642**	(1,133)
Investing Activities:				
Decrease in restricted cash	**343**	310	**158**	435
Decrease (increase) in short-term investments	**5,859**	-	**(4,744)**	40,010
Increase in other assets	**(834)**	431	**(3,146)**	(351)
Distributions received in excess of equity income	**(190)**	487	**2,940**	885
Receipt of principal on notes receivable	**110**	104	**1,059**	304
Decrease (increase) in non-controlling interest	**(22)**	-	**1,328**	-
Proceeds from liquidation of Highground assets	**734**	-	**1,073**	170
Increase in long-term investments and notes receivable	**-**	(2,094)	**(6,900)**	(8,659)
Net additions to property, plant and equipment	**(29,476)**	(2,662)	**(39,911)**	(14,638)
Acquisitions of operating entities (note 3(a))	**(132)**	(692)	**(98,226)**	(43,094)
	(23,608)	(4,116)	**(146,369)**	(24,938)
Effect of exchange rate differences on cash	**507**	(2)	**419**	(8)
Increase in cash	**6,873**	699	**10,776**	209
Cash, beginning of the period	**8,652**	2,007	**4,749**	2,497
Cash, end of the period	**$ 15,525**	$ 2,706	**$ 15,525**	$ 2,706
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	**$ 2,070**	$ 4,896	**$ 19,116**	$ 14,026
Cash paid during the period for income taxes	**$ 145**	$ (206)	**$ 192**	$ (81)
Non-cash transactions				
Property, plant and equipment acquisitions in accruals	**$ 6,699**	$ -	**$ 6,699**	$ -
Property installed by developers and conveyed	**$ -**	$ 86	**$ -**	$ 974

See accompanying notes to interim consolidated financial statements

Notes to the Unaudited Interim Consolidated Financial Statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water and energy utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements.

APUC's power generation business unit conducts business under the name Algonquin Power Co. ("APCo"), formerly Algonquin Power Income Fund. APCo owns or has interests in renewable energy facilities and thermal energy facilities representing more than 450 MW of installed electrical generation capacity. APUC's Utility Services business unit conducts business under the name of Liberty Utilities Co ("Liberty Utilities"). The utility businesses owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the States in which they operate. As a result of the current and expected growth of Liberty Utilities, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. As a result of this change, Liberty Utilities businesses operate under two separately managed regions – Liberty Utilities (South) (formerly known as Liberty Water) and Liberty Utilities (West) (formerly known as Liberty Energy - Calpeco). Liberty Utilities (South) currently owns a portfolio of utilities in the United States of America providing water or wastewater services in the states of Arizona, Texas, Missouri and Illinois. Liberty Utilities (West) currently owns a 50.001% interest in an electric distribution utility serving the Lake Tahoe region of California (the "California Utility"). APUC has announced an agreement to acquire, subject to regulatory approval, the remaining 49.999% interest in the California Utility (see note 3 (a)). Liberty Utilities has also announced an agreement to acquire, subject to regulatory approval, Granite State Electric Company, a New Hampshire electric distribution company, and EnergyNorth Natural Gas Inc., a regulated natural gas distribution utility (see note 3 (b)).

The regulated utility operating companies owned by Liberty Utilities are subject to regulation by the public utility commissions of 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 test year 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 all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

1. Significant accounting policies:

(a) Basis of preparation:

The unaudited interim consolidated financial statements and accompanying notes have been prepared in accordance with generally accepted accounting principles in the United States (U.S. GAAP) and follow disclosures required per Regulation S-X Rule 10-10, Interim Financial Statements provided by the Securities and Exchange Commission (SEC) Guidance. These are the Company's U.S. GAAP interim consolidated financial statements for part of the period covered by the first 2011 fiscal year U.S. GAAP annual financial statements. The consolidated interim financial statements do not include all of the information required for full annual financial statements.

The Company's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. These unaudited interim consolidated financial statements of APUC should be read in conjunction with the audited consolidated financial statements of APUC for the year ended December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the audited annual financial statements for the year ended December 31, 2010. Descriptions of the effect of the transition from Canadian GAAP to U.S. GAAP on the Company's financial position, financial performance and cash flows as at and for the two years ended December 31, 2010 are provided in note 24 of the audited consolidated financial statements for the year ended December 31, 2010. The accounting policies set out below have been consistently applied to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

APUC'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. APUC'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. During the winter period Liberty Energy (California) experiences higher demand for electricity than during the summer period since the utility serves a number of ski hills and resorts in the service territory.

1. Significant accounting policies (continued):

(b) Basis of consolidation:

The accompanying interim consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIE") where the Company is the primary beneficiary. Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE, as the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company.

Intercompany transactions and balances have been eliminated.

(c) Accounting for rate regulated operations:

APUC's regulated utility operating companies qualify for the application of regulatory accounting treatment in accordance with the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Management believes the existing regulatory assets are probable of recovery either because the Utilities received prior Regulator approval or due to regulatory precedent set for similar circumstances. Included in Note 7, Regulatory Assets & Liabilities are details of other regulatory assets and liabilities, and their current regulatory treatment

Under ASC 980, allowance for funds used during construction projects included in rate base is capitalized. This allowance is designed to enable a utility to capitalize financing costs during periods of construction of property subject to rate regulation. It represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction).

The electric utility's and the water utilities' accounts are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and NARUC, respectively.

(d) Cash:

Cash consists of cash deposited at banks.

(e) Short term investments:

Short term investments, consist of money market instruments with maturities commencing from October 2011 and are recorded at cost, which approximates current market value. Included in short term investments is an investment of $4,192 (U.S. $3,999) which is denominated in U.S. dollars (December 31, 2010 - $3,674 (U.S. $3,694)).

(f) Restricted cash:

Restricted cash represent reserves and amounts set aside pursuant to requirements of various debt agreements. Cash reserves segregated from APUC's cash balances are maintained in accounts administered by a separate agent and disclosed separately as restricted cash in these consolidated financial statements. APUC cannot access restricted cash without the prior authorization of parties not related to APUC.

(g) Accounts receivable

Trade accounts receivable are recorded at the invoiced amount and do not bear interest. The Company maintains an allowance for doubtful accounts for estimated losses inherent in its accounts receivable portfolio. In establishing the required allowance, management considers historical losses adjusted to take into account current market conditions and customers' financial condition, the amount of receivables in dispute, and the current receivables aging and current payment patterns. Account balances are charged against the allowance after all means of collection have been exhausted and the potential for recovery is considered remote. The Company does not have any off-balance-sheet credit exposure related to its customers.

(h) Property, plant and equipment:

Property, plant and equipment, consisting of land, facilities and equipment, are recorded at cost. The costs of acquiring or constructing facilities together with the related interest costs during the period of construction are capitalized. Interest costs capitalized for Liberty Utilities also include the allowance for equity funds used during construction.

1. **Significant accounting policies (continued):**

(h) Property, plant and equipment (continued):

Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

The facilities and equipment, which include the cost of major overhauls, are amortized on a straight-line basis over their estimated useful lives. For facilities these periods range from 6 to 65 years. Facility equipment and overhaul costs are amortized over 2 to 10 years.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility capital assets, with subsequent depreciation calculated on the net cost.

In accordance with regulator-approved accounting policies, when depreciable property, plant and equipment of Liberty Utilities are replaced or retired, the original cost plus any removal costs incurred (net of salvage) are charged to accumulated depreciation with no gain or loss reflected in results of operations. Gains and losses will be charged to results of operation in the future through adjustments to depreciation expense. In the absence of regulator-approved accounting policies, gains and losses on the disposition of property, plant and equipment would be charged to net earnings as incurred.

(i) Intangible assets:

Power sales contracts and energy sales contracts acquired in business combinations are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition for power sales contracts and 12 months for energy sales contracts.

Customer relationships acquired in business combinations are amortized on a straight-line basis over 40 years.

(j) Impairment of long-lived assets:

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. Recoverability is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

(k) Long-term investments and notes receivable:

Investments in which APUC has significant influence but not control or joint control are accounted using the equity method. APUC records its share in the income or loss of its investees in interest, dividend and other income in the Consolidated Statement of Operations. All other equity investments where APUC does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting, investments are carried at cost and the carrying amounts are adjusted only for other-than-temporary declines in value and additional investments. Income is recorded when dividends are received.

Notes receivable are financial assets with fixed or determined payments that are not quoted in an active market. Notes receivable that exceed one year and bear interest at a market rate based on the customer's credit quality are recorded at face value. Subsequent to acquisition, they are recorded at amortized cost using the effective interest method. The Company acquired these notes receivable as long-term investments and does not intend to sell these instruments prior to maturity.

An allowance for impairment loss on notes receivable is recorded if it is expected that the Company will not collect all principal and interest contractually due. The impairment is measured based on the present value of expected future cash flows discounted at the note's effective interest rate. The Company does not accrue interest when a note is considered impaired. When ultimate collectability of the principal balance of the impaired note is in doubt, all cash receipts on impaired notes are applied to reduce the principal amount of such notes until the principal has been recovered and are recognized as interest income thereafter. Impairment losses are charged against the allowance and increases in the allowance are charged to bad debt expense. Notes are written off against the allowance when all possible means of collection have been exhausted and the potential for recovery is considered remote.

(l) Other long-term liabilities:

Other long-term liabilities include advances in aid of construction. Certain of APUC's water, wastewater and electric utilities are periodically provided with advances through contributions from customers, real estate developers and builders for water, sewage and transmission line extensions in order to extend water, sewer and power service to their properties. The amounts advanced are generally repayable over a prescribed period based on revenues generated by the housing or development in

1. **Significant accounting policies (continued):**

(l) Other long-term liabilities (continued):

the area being developed as new customers are connected to and take service from the utilities. Generally, advances not refunded within the prescribed period are not required to be repaid. These amounts are recorded as Advances in Aid of Construction in other long-term liabilities. After all refunds are made, any remaining unpaid balance is transferred to contributions in aid of construction.

Other long-term liabilities also include deferred water rights. Deferred water rights are related to a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment which is a form of lease inducement. An annual average rate for water rights was estimated for the entire life of the lease and that average rate is being expensed over the lease term. The result of this policy is that the deferred water rights inducement amount recorded in the first ten years is being drawn down in the last forty years.

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Utilities' obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement.

(m) Recognition of revenue:

Revenue derived from energy generation sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers.

Revenue from waste disposal is recognized on 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 is recognized based on actual tonnage at the expected price for the contract year.

Revenues related utility energy sales and distribution are recorded based on metered energy consumptions by customers, which occurs on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns, line loss and current tariffs.

Accounts receivable as of September 30, 2011, include unbilled receivables of $8,224 (December 31, 2010 - $1,560). Interest from long-term investments is recorded as earned.

(n) Foreign currency translation:

The Company's reporting currency is the Canadian dollar.

The Company's US operations are determined to have the U.S. dollar functional currency since the preponderance of operating, financing and investing transactions are denominated in U.S. dollars. The financial statements of these operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the financial statements of these entities are reported as a component of other comprehensive income ("OCI") and are accumulated in a component of equity on the balance sheet and are not recorded in income unless there is a complete liquidation of the investment.

(o) Asset retirement obligations:

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations. Actual expenditures incurred are charged against the accumulated obligation. Based on APUC's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations have been recorded.

1. Significant accounting policies (continued):

(p) Income taxes:

Income taxes are accounted for using the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is recorded against deferred tax assets to the extent that it is considered more likely than not that the deferred tax asset will not be realized. The effect on deferred assets and liabilities of a change in tax rates is recognized in earnings in the year that includes the date of enactment.

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company follows the FASB ASC 740-10 Interpretation No., "Accounting for uncertainty in Income Taxes—An Interpretation of FASB Statement No. 109". The Company recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(q) Financial instruments and derivatives:

APUC has classified its cash, short term investments, accounts receivable, restricted cash, accounts payable and accrued liabilities and dividends payable as held-for-trading, which are measured at fair value. Notes receivable are classified as loans and receivables, which are measured at amortized cost as there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are classified as other financial liabilities, which are measured at amortized cost, using the effective interest method.

Transaction costs that are directly attributable to the acquisition of financial assets are accounted for as part of the respective asset`s carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Transaction costs that are directly attributable to the issuance of financial liabilities, costs of arranging the Company`s credit facility and costs considered as commitment fees paid to financial institutions are recorded in deferred financing costs. Deferred financing costs relating to term debt are amortized using the effective interest method while deferred financing costs relating to revolving credit facilities are amortized on a straight-line basis over the term of the facility.

Unrealized holding gains and losses on trading securities are included in earnings. A decline in the market value of any held-to-maturity security below cost that is deemed to be other-than-temporary results in an impairment to reduce the carrying amount to fair value. To determine whether an impairment is other-than-temporary, the Company considers all available information relevant to the collectability of the security, including past events, current conditions, and reasonable and supportable forecasts when developing estimate of cash flows expected to be collected. Evidence considered in this assessment includes the reasons for the impairment, the severity and duration of the impairment, changes in value subsequent to year end, forecasted performance of the investee, and the general market condition in the geographic area or industry the investee operates in.

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values and the change in fair value is included in the Consolidated Statements of Operations. None of the derivatives were designated in hedging relationships for accounting purposes.

(r) Fair Value Measurements

The Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible. The Company determines fair value based on assumptions that market participants would use in pricing an asset or liability in the principal or most advantageous market. When considering market participant assumptions in fair value measurements, the following fair value hierarchy distinguishes between observable and unobservable inputs, which are categorized in one of the following levels:

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.

1. Significant accounting policies (continued):

(r) Fair Value Measurements (continued):

- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(s) Stock Based Compensation

The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value using the Black-Scholes option pricing model. The estimated fair value of the options, including the effect of estimated forfeitures, is recognized as expense on a straight line basis over the options` vesting period while ensuring the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

(t) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of deferred tax assets, assessments of asset retirement obligations, and the fair value of financial instruments, derivatives and stock options. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Recently issued accounting pronouncements

(a) Recently Adopted Accounting Pronouncements

In December 2010, the FASB issued ASC update No. 2010-28, "Intangibles-Goodwill and Other (Topic 350), When to Perform Step 2 of the Goodwill Impairment Test for Reporting Units with Zero or Negative Carrying Amounts, a consensus of the FASB Emerging Issues Task Force." This amendment modifies guidance for Step 1 of the goodwill impairment test for reporting units with zero or negative carrying amounts. The adoption of this update did not have a material impact on the Company`s financial statements.

In December 2010, the FASB issued ASC update No. 2010-29, "Business Combinations (Topic 805), Disclosure of Supplementary Pro Forma Information for Business Combinations, a consensus of the FASB Emerging Issues Task Force." This amendment clarifies the periods for which pro forma financial information is presented. The adoption of this update did not have a material impact on the Company`s financial statements.

(b) Recent Accounting Guidance Not Yet Adopted

In September 2011, the FASB issued ASC update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment". This Update revises how an entity tests goodwill for impairment. The new guidance allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity is no longer required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. This guidance is effective for the Company's quarter ending March 31, 2012, but the Company intends to early adopt for the financial statements for the year ending December 31, 2011 as allowed under the guidance. The Company believes there will be no material impact on the Company`s financial statements from the adoption of these amendments.

In June 2011, the FASB issued ASC update No. 2011-05 "Comprehensive income (Topic 220)". This Update provides accounting guidance on presentation of comprehensive income. The new guidance eliminates the current option to report OCI and its components in the statement of changes in stockholders equity. The new guidance requires the changes in OCI be presented either in a single continuous statement of net income and OCI or in two separate but consecutive statements. The new guidance will be effective for the Company's quarter ending March 31, 2012, but the Company intends to early adopt during its annual financial statements for the year ending December 31, 2011 as allowed under the guidance. The amendments will result in presentation changes only in the financial statements.

In May 2011, the FASB issued ASC update No. 2011-04 "Fair Value Measurement (Topic 820)". This Update amends the accounting and disclosure requirements for fair value measurements. The new guidance expands the disclosures about fair value measurements categorized within Level 3 of the fair value hierarchy and requires categorization by level of the fair value hierarchy for items that are

2. Recently issued accounting pronouncements (continued):

(b) Recent Accounting Guidance Not Yet Adopted (continued):

not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The new guidance will be effective for the Company's quarter ending March 31, 2012, will be applied prospectively. Other than requiring additional disclosures, the adoption of this guidance is not expected to have a material impact on the Company's consolidated financial statements.

3. Acquisitions

(a) Acquisition of electrical generation and regulated distribution utility

On January 1, 2011, APUC and Emera Inc. ("Emera") closed the acquisition of the "California Utility" for a purchase price of approximately $136,768 (US $137,510), subject to a final post-closing purchase price adjustment. APUC owns 50.001% of shares of California Pacific Utility Ventures LLC, which acquired the California Utility through its wholly owned subsidiary Liberty Energy (California) and has concluded it controls the acquired entity. Liberty Energy (California) provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The other 49.999% of the shares were acquired by Emera in the same transaction. The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date, as well as the fair value at the acquisition date of the non-controlling interest in Liberty Energy (California):

Working capital	$	8,964
Property, plant and equipment		146,064
Goodwill		10,325
Current portion of other long-term liabilities		(671)
Other long-term liabilities		(12,422)
Regulatory liabilities		(16,918)
Total net assets acquired	$	135,342

During the third quarter approximately $1,426 of property, plant and equipment related to the California Utility was deemed to have been acquired by the California Utility after the acquisition date and as a result excluded from the purchase price allocation. Emera's share of this additional property, plant and equipment of approximately $713 is recorded as reduction in non-controlling interest as per the terms of the agreement. The acquisition was funded as follows:

Contribution of equity by APUC in 2011	$	29,073
Contribution of equity by APUC in 2010		3,787
Non-controlling interest portion of purchase price paid by Emera		32,860
Debt financing		69,622
Total acquisition cost		135,342

As a result the total consideration payable by APUC in 2011 is $98,965.

In connection with the acquisition, the Company issued 8,523,000 shares at a price of $3.25 per share to Emera pursuant to a subscription receipt agreement. The $27,700 cash proceeds of the subscription receipts were used to fund a portion of the cost of acquisition of the California Utility.

The determination of the fair value of assets and liabilities acquired has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. The Company has not completed all of the fair value measurements at September 30, 2011. In particular, the fair values of the acquired property, plant and equipment, and long-term liabilities are provisional pending completion of the final valuations.

In addition, the purchase agreements provides for a final purchase price adjustment based on final agreed working capital and rate base balances at the acquisition date. The Company will continue to review information and perform further analysis prior to finalizing the allocation of the purchase price. The actual fair values of the assets and liabilities will be determined as of the date of acquisition and may differ from the amounts noted above in the preliminary purchase price allocation.

Goodwill is calculated as the excess of the purchase price over the fair value of net assets acquired and the contributing factors to the amount recorded include expected future cash flows, potential operational synergies, the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. All of the goodwill was allocated to the Liberty Utilities (West) segment.

3. Acquisitions (continued):

(a) Acquisition of electrical generation and regulated distribution utility (continued):

Property, plant & equipment of Liberty Energy (California) are amortized on a straight line basis, ranging from 6 to 65 years in accordance with the regulatory requirements.

The Company recorded $2,595 in total acquisition costs relating to the Liberty Energy (California) acquisition of which $22 (2010 - $364) and $385 (2010 - $692) were incurred in the three and nine months ended September 30, 2011 respectively. All such costs have been expensed in the financial statements.

Liberty Energy (California) contributed revenue of $16,663 and $56,082 and earnings of $551 and $5,800 to the Company's results for the three and nine months ended September 30, 2011. The disclosure of pro forma revenue and earnings related to 2010 is impracticable since the assets acquired were part of a division and the operating costs were subject to extensive allocation.

During the three and nine months ended September 30, 2011, non-controlling interests increased by $0 and $1,350 respectively due to contributions made by the non-controlling interest for Emera's share of additional property, plant and equipment acquired during the period relating to the acquisition.

On April 29, 2011, Emera agreed to sell its 49.999% interest in Liberty Energy (California) to APUC in exchange for 8,211,000 shares of APUC. The transaction is subject to regulatory approval and is expected to close in 2012.

(b) Acquisition of Regulated Water Utility Assets

On September 20, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of Noel Water Co., Inc. ("Noel"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition.

Total acquisition cost amounted to $903, which was paid in cash. The following assets were acquired at fair values: working capital of $28, and, property plant and equipment of $729. Goodwill amounting to $146 was recognized.

On November 9, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of KMB Utility Corporation ("KMB") for total consideration of US$353.

Both utilities are located in the state of Missouri.

(c) Agreement to Acquire New Hampshire Electric and Gas Utilities

On December 9, 2010 APUC announced that Liberty Utilities had entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company, a regulated electric utility, and EnergyNorth Natural Gas Inc. a regulated natural gas utility from National Grid USA ("National Grid") for total cash consideration of US $285,000 plus working capital and subject to final closing adjustment.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 12,000,000 APUC common shares upon closing of the transactions at a purchase price of $5.00 per share. The receipt of cash from Emera and issuance of the shares is contingent on closing of these acquisitions and consequently the subscription receipts have not been recorded in the financial statements.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

(d) Agreement to Acquire Mid-west Gas Utilities

On May 13, 2011, APUC announced that Liberty Utilitieshas entered into an agreement with Atmos Energy Corporation ("Atmos Energy") to acquire certain regulated natural gas distribution utility assets (the "Mid-west Utilities") located in Missouri, Iowa, and Illinois. Total purchase price for the Mid-west Utilities is approximately U.S. $124,000 , subject to certain working capital and other closing adjustments.

Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in 2012.

(e) Investment in Northeast Wind Projects

On April 30, 2011, APUC, together with Emera and First Wind Holdings, LLC ("First Wind"), entered into an agreement to jointly construct, own and operate wind energy projects in the Northeastern U.S. through a newly formed operating company. First Wind has a 370 MW portfolio of wind energy projects in the Northeast U.S. including six operating projects and one project

3. Acquisitions (continued):

(e) Investment in Northeast Wind Projects (continued):

near operation. These assets will become part of an operating company of which First Wind will own 51% and, Emera and APUC through a separate joint venture ("Northeast Wind"), will own 49% of the operating company.

Northeast Wind will invest approximately US$333,000 in the operating company including a loan in the amount of US$150,000 to acquire the 49% ownership of the operating company. APUC's investment in Northeast Wind will be approximately US$83,000 for a 25% ownership interest.

In connection with these acquisitions, Emera has agreed to a treasury subscription of subscription receipts convertible into 6,900,000 APUC common shares upon closing of the transactions at a purchase price of $5.37 per share. The receipt of cash from Emera and issuance of the shares is conditional on and is planned to occur simultaneously with the closing of these acquisitions and consequently the subscription receipts have not been recorded in the financial statements.

(f) Acquisition of Hydroelectric Generation Assets ("Tinker Acquisition")

On January 12, 2010, APUC acquired certain electrical generating facility assets located in New Brunswick and Maine. The acquisition consisted of three hydroelectric generating stations, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick. The acquisition also included five thermal generating stations and certain regulated New Brunswick Independent System Operator transmission lines located in proximity to the generating facilities. In connection with the Tinker Acquisition, on February 4, 2010, APUC also acquired a related energy services business ("Energy Services Business").The Energy Services Business retails the electricity generated by the Tinker facilities to commercial and industrial customers in northern Maine.

The total purchase price was $40,281. The acquisition has been accounted for using the acquisition method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been allocated to net assets acquired as follows:

Working capital (net of cash received of $1)	$	69
Property, plant and equipment		40,427
Intangible asset – energy sales contracts		4,421
Non-current deferred income tax liability		(1,262)
Derivative liability – energy forward purchase contracts		(3,374)
Total cash consideration	$	40,281

The allocation of the purchase price has been based upon the fair values of the assets and liabilities as of the date of acquisition.

(g) Acquisition of Water Utility System ("the Galveston Utility")

On March 17, 2010 Liberty Water, a wholly owned subsidiary of APUC, acquired a water distribution and wastewater collection system located near Galveston, Texas for a total purchase price of $2,038. The Galveston Utility provides water distribution and wastewater collection services to approximately 260 equivalent residential connections.

The acquisition has been accounted for using the acquisition method, with earnings from operations included since the date of acquisition.

The consideration paid by APUC has been allocated to net assets acquired as follows:

Property, plant and equipment	$	2,023
Intangible asset		15
Total cash consideration	$	2,038

4. Long-term investments and notes receivable

(a) Red Lily I

On April 19, 2010, the Company entered into agreements to provide development, construction, operation and supervision services related to the construction, commissioning and operation of a 26.4 megawatt wind energy facility ("Red Lily I") in south-eastern Saskatchewan.

The equity in Red Lily I ('the Partnership") is owned by an independent investor. The Company's investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Partnership. APUC's commitment under the senior debt facility is to advance up to $13,000 of the Tranche 2 senior debt. The third party lender

4. Long-term investments and notes receivable (continued):

(a) Red Lily I (continued):

has also committed to provide $31,000 of senior debt to the Partnership. The senior debt will earn an interest rate of 6.31% and will mature five years following commissioning of the project. The senior debt is secured by substantially all the assets of the Partnership.

A second tranche of subordinated debt for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced five years following commissioning of the project. The proceeds from this additional

subordinated debt are required to be used to repay Tranche 2 of the Partnership's senior debt, including APUC's portion. The subordinated debt earns an interest rate of 12.5%, the principal matures 25 years following commissioning of the project but is repayable by Red Lily in whole or in part at any time after five years, without a pre-payment premium. The subordinated debt is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated debt of up to $19,500, exercisable for a period of 90 days commencing five years from the date of commissioning of the project.

During the three and nine months ended September 30, 2011, APUC advanced $0 and $6,900 respectively of the senior debt to the Red Lily Partnership. As of September 30, 2011 APUC has funded a total of $13,000 (December 31, 2010 - $6,100) of the senior debt and $6,565 (December 31, 2010 - $6,565) of the subordinated debt.

5. Property, plant and equipment

Property, plant and equipment consist of the following:

September 30 , 2011

	Cost	Accumulated depreciation	Net book value
Land	$ 12,371	$ -	$ 12,371
Facilities	1,075,333	229,440	845,893
Equipment	146,316	52,987	93,329
	$ 1,234,020	$ 282,427	$ 951,593

December 31, 2010

	Cost	Accumulated depreciation	Net book value
Land	$ 11,976	$ -	$ 11,976
Facilities	948,789	226,437	722,352
Equipment	48,720	21,309	27,411
	$ 1,009,485	$ 247,746	$ 761,739

In August 2011, hurricane Irene impacted four of our hydro facilities, with flooding causing damage to structures and roadways. As a result, two small facilities with total net book value of $2,580 have been taken offline. The Company is currently assessing the financial impact, extent of insurance coverage and our plans for future operations of these facilities

6. Intangible assets

Intangible assets consist of the following:

September 30, 2011

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 93,079	$ 38,310	$ 54,769
Customer relationships	19,825	3,443	16,382
Energy sales contract	4,456	4,456	-
Licenses and agreements	683	683	-
	$ 118,043	$ 46,892	$ 71,151

December 31, 2010

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 102,980	$ 45,345	$ 57,635
Customer relationships	18,811	2,912	15,899
Energy sales contract	4,228	3,876	352
Licenses and agreements	683	683	-
	$ 126,702	$ 52,816	$ 73,886

7. Regulatory assets and liabilities

Regulatory assets and liabilities consist of the following:

	Receiving Regulatory Treatment	Pending Regulatory Treatment	September 30, 2011	December 31, 2010
Regulatory assets:				
Rate case costs (i)	$ 2,353	$ -	$ 2,353	$ 2,164
Alternative revenue program (ii)	2,426	-	2,426	320
Water testing costs (iii)	79	-	79	-
Total regulatory assets				
Regulatory liability:	4,858	-	4,858	2,484
Deferred energy cost (iv)	$ (5,673)	$ -	$ (5,673)	$ -
Cost of removal (v)	(14,308)	-	(14,308)	-
Total regulatory liabilities	$ (19,981)	-	$ (19,981)	$ -

(i) Deferred rate case costs

Deferred rate case costs relate to costs incurred by APUC's utilities to file, prosecute and defend rate case applications and which the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator of approximately three years. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

(ii) Alternative revenue program

A rate decision by the regulator of one of Liberty Water's utilities has ordered a phase-in of the rate increases it has granted wherein the full rate increase will be phased in over a 12 month period. The phase-in will also include a surcharge mechanism that ensures the utility is not disadvantaged by the phase in of the new rates. The details around the phase-in mechanism are the subject of a separate regulatory proceeding that is expected to conclude prior to the end of the phase in period in 2011. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

(iii) Water testing costs

Water testing costs consist of certain expenses associated with some water testing costs ordered by the regulator. These costs are allowed to be recovered in rates in future periods. The regulatory asset associated with these costs is amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

7. Regulatory assets and liabilities (continued):

(iv) Deferred Energy Accounting

Certain state statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased gas, fuel and purchased power.

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the statement of operations but rather is deferred and recorded as a regulatory asset on the balance sheet in accordance with the provisions of the Regulated Operations Topic of the FASB. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to regulatory review.

The Utilities also record and are eligible under the statute to recover a carrying charge on such deferred balances.

(v) Cost of removal

In addition to the legal asset retirement obligations booked under the accounting guidance for asset retirement obligations, the Utilities have accrued for the cost of removing non-contractual retirement obligations of other electric assets. This treatment is as required by the regulators.

8. Long-term liabilities

In February 2011, APCo renewed its senior secured revolving credit facility in the maximum amount of $142,000 (the "Facility") for a three year term with its Canadian bank syndicate. The Facility now has a maturity date of February 14, 2014. Refinancing costs and fees related to the renewal of $1,081 have been recorded as deferred financing costs in the period. On July 25, 2011, in conjunction with the APCo debenture offering discussed below, the maximum availability on the senior revolving facility was reduced to $120,000.

The Liberty Energy (California) acquisition (note 3(a)) was funded in part with proceeds of a U.S.$70,000 senior unsecured private debt placement consisting of U.S. $45,000 bearing an interest rate of 5.19% maturing December 29, 2020 and U.S. $25,000 bearing an interest rate of 5.59% maturing December 29, 2025. The notes are interest only, payable semi-annually. Financing costs of $1,069 incurred with respect to this placement have been recorded in deferred financing costs.

On July 25, 2011 APUC completed a $135,000 private placement debt financing commitment at a price of $998.28 per $1,000 principal amount of debenture for its subsidiary, APCo. The notes are senior unsecured with a seven year maturity date of July 25, 2018 and bears interest at 5.5%. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012. APCo incurred deferred financing costs of $1,550, which is amortized to interest expense over the term of the loan using the effective interest rate method. The net proceeds of this financing were used to retire the project debt related to the St. Leon facility (Air Source Senior Debt Financing) and to reduce amounts outstanding on APCo's senior secured revolving credit facility. As of September 30, 2011, the Company had accrued $1,383 in interest payable.

9. Convertible Debentures

		Series 1A		**Series 2A**		**Series 3**		**Total**
Maturity date		2014 November 30		2016 November 30		2017 June 30		
Interest rate		7.50%		6.35%		7.00%		
Conversion price per share	$	4.08	$	6.00	$	4.20		
Carrying value at December 31, 2010	$	59,156	$	59,698	$	62,905	$	181,759
Conversion to shares (Note12), net of costs		(59,449)		-		(205)		(59,654)
Accretion of discount and conversion option		293		29		-		322
Carrying value at September 30, 2011	$	-	$	59,727	$	62,700	$	122,427
Face value at September 30, 2011	$	-	$	59,967	$	62,700	$	122,667

On May 16, 2011 ("Redemption Date"), APUC redeemed all of the issued and outstanding Series 1A Debentures. Between April 1, 2011 and the Redemption Date, a principal amount of $60,266 of Series 1A Debentures were converted into 14,771,185 shares of APUC. APUC redeemed the remaining Series 1A Debentures by issuing and delivering 430,666 APUC shares. On September 30, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

During the nine month period ended September 30, 2011, $205 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 48,807 shares of APUC.

10. Other long-term liabilities

Other long term liabilities consist of the following:

	September 30, 2011	December 31, 2010
Advances in aid of construction (note 1(l))	$ 76,903	$ 55,115
Contingent consideration	1,172	1,198
Deferred water rights inducement	2,947	3,008
Customer deposits	2,986	1,985
Capital Leases		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	569	535
Other	5,273	5,099
	89,850	66,940
Less: current portion	(1,849)	(1,011)
	$ 88,001	$ 65,929

11. Comprehensive Income

The following table summarizes the allocation of total comprehensive income between shareholders of APUC and non-controlling interests:

	APUC shareholders	Non-controlling interests	Three months ended September 30, 2011	Three months ended September 30, 2010
Consolidated net income	19,584	819	20,403	1,364
Attributions to St Leon Class B Unit holders	-	(104)	(104)	(104)
OCI:				
Net foreign currency translation gain (loss)	19,503	3,184	23,289	(8,915)
Total comprehensive income	39,087	3,899	43,588	7,655

	APUC shareholders	Non-controlling interests	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Consolidated net income	31,930	3,466	35,396	2,635
Attributions to St Leon Class B Unit holders	-	(346)	(346)	(315)
OCI:				
Net foreign currency translation gain (loss)	12,828	2,083	14,911	(43,058)
Total comprehensive income (loss)	44,758	5,203	49,961	(40,738)

12. Shareholders' Equity

Number of common shares:

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Common shares, beginning of period	119,199,940	95,099,989	95,422,778	95,099,989
Conversion and redemption of convertible debentures (note 9)	14,284 -	-	15,268,446	-
Issuance of shares (note 3(a))	-	-	8,523,000	-
Common shares, end of period	119,214,224	95,099,989	119,214,224	95,099,989

The following tables provide a reconciliation of the beginning and the ending carrying amounts of total equity, equity attributable to APUC shareholders, and equity attributable to non-controlling interest.

12. Shareholders' Equity (continued):

For the nine months ended September 30, 2011:

	Common shares	Equity component of convertible debentures	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2010	$ 795,329	$ 1,504	$ 108	$ (358,542)	$ (99,845)	-	$ 338,554
Dividends declared to APUC shareholders	-	-	-	-	(22,856)	-	(22,856)
Conversion and redemption of convertible debentures	59,834	(815)	-	-	-	-	59,019
Issuance of common shares	27,700	-	-	-	-	-	27,700
Stock compensation expense	-	-	445	-	-	-	445
Acquisition of Liberty Energy (California)	-	-	-	-	-	34,187	34,187
Amounts received in connection with Highground transaction (note 13)	1,073	-	-	-	-	-	1,073
Comprehensive income	-	-	-	31,930	12,828	5,203	49,961
Balance, September 30, 2011	$ 883,936	$ 689	$ 553	$ (349,468)	$ (87,017)	$ 39,390	$ 488,083

For the nine months ended September 30, 2010:

	Common shares	Equity component of convertible debentures	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2009	$ 785,828	$ 1,487	-	$ (352,219)	$ (48,712)	-	$ 386,384
Dividends declared to APUC shareholders	-	-	-	(17,040)	-	-	(17,040)
Conversion and redemption of convertible debentures	3,290	(46)	-	-	-	-	3,244
Stock compensation expense	-	-	34	-	-	-	34
Amounts received in connection with Highground transaction (note 13)	170	-	-	-	-	-	170
Issuance pursuant to management internalization	4,763	-	-	-	-	-	4,763
Comprehensive income (loss)	-	-	-	2,319	(43,058)	-	(40,739)
Balance, September 30, 2010	$ 794,051	$ 1,441	$ 34	$ (366,940)	$ (91,770)	-	$ 336,816

12. Shareholders' Equity (continued):

Stock Option Plan

On March 22, 2011, the board of directors of APUC ("Board") approved the grant of 892,107 options to senior executives of the Company. The options allow for the purchase of common shares at a price of $5.23, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

On June 21, 2011, the Board approved the grant of 171,642 options to a senior executive of APCo. The options allow for the purchase of common shares at a price of $5.64, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of grant.

On July 28, 2011 the Board approved the grant of 90,909 options to a senior executive of APUC. The options allow for the purchase of common shares at a price of $5.74, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of the grant.

On September 13, 2011 the Board approved the grant of 172,242 options to a senior executive of Liberty Utilities. The options allow for the purchase of common shares at a price of $5.68, the market price of the underlying common share at the date of grant. One-third of the options vest on each of January 1, 2012, 2013 and 2014. Options may be exercised up to eight years following the date of the grant.

The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The following assumptions were used in determining the fair value of share options granted:

	2011	2010
Risk-free Interest	2.1%-3.3%	2.9%
Expected Volatility	28.2%-36.9%	29.2%
Expected dividend yield	4.4%-5.9%	5.9%
Expected Life	8 years	8 years
Weighted average grant date fair value per option	$ 0.99	$ 0.61

The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical rates in dividends of our shares.

For the three and nine month period ended September 30, 2011, APUC recorded, respectively $228 and $445 (2010 - $34 and $34), in compensation expense. As at September 30, 2011, there was $1,460 of total unrecognized compensation costs related to stock options granted under the Plan. The cost is expected to be recognized over a period of 2.0 years.

As at September 30, 2011, 386,735 options with an intrinsic value of $657 are exercisable. No share options were exercised in 2011 or 2010. The intrinsic value of the 2,487,104 options as at September 30, 2011 was $2,468.

Performance Share Units

In October 2011, the Company issued 28,370 performance share units (PSUs) to its employees as part of the Company's long-term incentive program. At the end of the three-year performance periods, the number of shares vested can range from 0% to 144% of the number of PSUs granted. Dividends accumulate during vesting period and are converted to PSUs based on the market value of the shares on that date. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized ratably over the performance period based on the Company's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

Employee Share Purchase Plan

In September 2011, the Company approved an employee share purchase plan (ESPP) commencing in October 2011. Eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match up to 20% of employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually. Shares purchased through the Company match portion vest over a one year period. At the Company's option, the shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

12. Shareholders' Equity (continued):

Directors Deferred Share Units

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units (DSUs) in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period. As at September 30, 2011, no DSUs had been issued.

13. Related party transactions

Certain executives of APUC are shareholders of Algonquin Power Management Inc. (APMI), the former manager of APCo. A member of the Board of Directors of APUC is an executive at Emera.

APUC 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 three and nine months ended September 30, 2011 were $82 and $245 (2010 - $82 and $245).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the three and nine months ended September 30, 2011, APUC incurred costs in connection with the use of the aircraft of $226 and $350 (2010 - $162 and $370) and amortization expense related to the advance against expense reimbursements of $77 and $205 (2010 - $36 and $99). At September 30, 2011, the remaining amount of the advance was $349 (2010 - $460) and is recorded in other assets.

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), an indirect subsidiary of APUC and the legal owner of the St. Leon facility. 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 June 17, 2008 growing to a maximum of 10% by year 15. 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 related holders of the Class B units are entitled to cash distributions of $121 and $208 for the three and nine months ended September 30, 2011 (2010 - $63 and $189).

APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the nine months ended September 30, 2011, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount is included in accrued liabilities at September 30, 2011.

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") which is a non-APUC entity. APUC and APS have agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit.

As at September 30, 2011, included in amounts due from related parties is $511 (December 31, 2010 - $718) owed from APMI and included in amounts due to related parties is $1,661 (December 31, 2010 - $901) owed to APMI. These amounts arise from the transactions described above.

A contract with a subsidiary of Emera to purchase energy on Independent System Operator New England ("ISO NE") and provide scheduling services on ISO NE was included as part of the acquisition of the Energy Services Business associated with the Tinker Acquisition. The contract expired March 31, 2010 and was not renewed. As a result of this contract, during 2010 a subsidiary of Emera provided services to and purchased energy on ISO NE on behalf of the Energy Services Business. In this capacity, for the three and nine months ended September 30, 2011 APUC paid a subsidiary of Emera an amount of $0 (2010 - $1,368) which was included as an operating expense on the consolidated statement of operations.

In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the three and nine months ended September

13. Related party transactions (continued):

30, 2011 APUC paid U.S. $84 and $187 (2010 - $71 and $132) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company (“MPS”). For the three and nine months ended September 30, 2011, the Energy Services Business sold electricity amounting to $1,659 and $5,301 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

As of September 30, 2011, included in amounts due from related parties is $1,672 (2010 - $0) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.

In May 2011, the Company received $339 from CJIG Management Inc. (“CJIG”), as its share of 50% of the additional proceeds received by CJIG from the further liquidation of the assets held by Highground Capital Corporation. In August 2011 the Company received an additional $734 from CJIG. The payments have been recorded as an increased amount assigned to the equity originally issued in connection with the Highground transaction.

The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

14. Commitments and Contingencies

Contingencies:

APUC and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider APUC’s exposure to such litigation to be material to these financial statements. Accruals for any contingencies related to these items are recorded in the financial statements at the time it is concluded that its occurrence is probable and the related liability is estimable.

On December 19, 1996, the Attorney General of Québec (“Québec AG”) filed a suit in Québec Superior Court against a subsidiary of APUC claiming for amounts that the APUC subsidiary has been paying to The St. Lawrence Seaway Management Corporation (the “Seaway Management”) under its water lease with the Seaway Management. The water lease contains a “hold harmless” clause which mitigates this claim. As such, the APUC subsidiary brought the Attorney General of Canada and the Seaway Management (the “Federal Authorities”) into the proceedings in an action in warranty. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG and suspended the action in warranty following final judgment in this case.

The Québec AG subsequently appealed this decision and on October 21, 2011 the Québec Court of Appeal allowed the appeal and condemned the APUC subsidiary to pay approximately $5.4 million which includes the amount claimed with interest.

The APUC subsidiary believes it is held harmless in its water lease from this decision and therefore may recommence the action in warranty in the Superior Court or negotiate a settlement with the Federal Authorities. In addition, it is possible the Federal Authorities and the APUC subsidiary might desire to seek leave to appeal this decision to the Supreme Court of Canada. As a result, the probability of any loss and its quantification cannot be estimated at this time. Accordingly no accruals for amounts owed or recoverable in respect of the water lease dues already paid to the Seaway Management have been recorded in the financial statements.

Commitments:

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at September 30, 2011.

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated potential remedial measures involving capital expenditures of approximately $17,095 which may be required to comply with the legislation and which would be invested over a five year period or longer.

14. Commitments and Contingencies (continued):

APUC has outstanding purchase commitments for long-term service agreements, capital project commitments and operating leases. Detailed below are estimates of future commitments under these arrangements:

	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Long term service agreements	$ 3,156	$ 3,934	$ 4,133	$ 4,215	$ 4,300	$ 74,088	$ 93,826
Capital projects	29,616	-	-	-	-	-	29,616
Operating leases	983	643	431	290	21	-	2,368
Total	$ 33,755	$ 4,577	$ 4,564	$ 4,505	$ 4,321	$ 74,088	$ 125,810

15. Cash dividends

All cash dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the three and nine months ended September 30, 2011, the Company paid cash dividends to shareholders totaling $7,748 and $20,236 respectively (2010 - $5,703 and $13,192) or $0.065 and $0.19 per common share (2010 - $0.06 and $0.18 per common share).

On August 11, 2011, the Board approved an annual dividend increase of $0.02 per common share for a total annualized dividend of $0.28, paid quarterly at a rate of $0.07 per common share. The Board declared a dividend on the Company's shares of $0.07 per share payable on October 17, 2011 to the shareholders of record on September 30, 2011 for the period from July 1, 2011 to September 30, 2011.

16. Changes in non cash operating working capital

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

	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
Accounts receivable	$ 3,012	$ (286)	$ 139	$ (3,246)
Related party balances	1,453	-	105	-
Supplies and consumables inventory	(659)	-	(1,089)	-
Income tax receivable	-	(231)	-	567
Prepaid expenses	(1,396)	(309)	(1,327)	1,252
Accounts payable	(5,139)	(3,795)	(2,241)	(2,391)
Accrued liabilities	13,143	-	13,180	-
Current income tax liability	129	469	610	782
	$ 10,543	$ (4,152)	$ 9,377	$ (3,036)

17. Basic and diluted net earnings per share

Basic and diluted earnings per share have been calculated on the basis of net earnings attributable to the Company and the weighted average number of shares outstanding during the year. The weighted average shares outstanding during the year are as follows:

	Three months ended September 30, 2011	2010	Nine months ended September 30, 2011	2010
Weighted average shares/units – basic	119,212,025	95,099,989	111,963,782	94,063,029
Dilutive effect of stock options	252,894	-	191,884	-
Weighted average shares – diluted	119,464,919	95,099,989	112,155,666	94,063,029

The shares potentially issuable as a result of the convertible debentures are excluded from this calculation as they are anti-dilutive.

18. Income taxes

For the nine months ended September 30, 2011, the Company's overall effective tax rate was different than the statutory rate of 28.25% due primarily to recognition of deferred credits, change in valuation allowances, recognition of other comprehensive income in US entities, and non deductible expenses.

Included in deferred income tax recoveries for the three and nine month periods ended September 30, 2011 is $1,875 and $5,424 (2010- $2,730 and $5,007) related to the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer.

19. Segmented Information

APUC has two broad operating segments: APCo which owns or has interests in renewable energy facilities and thermal energy facilities and Liberty Utilities which owns and operates utilities in the United States of America providing water, wastewater and local electric distribution services.

Within APCo there are three 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 the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

Effective July 2011, the Company changed its operational segments within Liberty Utilities to be reportable by geography territory rather than type of utility. As a result Liberty Utilities now reports results under Liberty Utilities (West) Region (currently consisting of Calpeco) and Liberty Utilities (South) Region (currently consisting of Liberty Water). No changes in the aggregation of segmented financial information were required as a result of this change. As additional utilities are acquired, additional reportable segments by geographic territory may be added.

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy and Liberty Utilities (South) and Liberty Utilities (West). The development activities of APCo are reported under Renewable Energy or Thermal Energy as appropriate. For purposes of evaluating divisional performance, the Company allocates the realized portion of the loss on 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 derivatives instruments is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment. The interest rate swaps relate to specific debt facilities and gains and losses are allocated in the same manner as interest expense. Amounts relating to the convertible debentures are reported in the corporate segment.

The results of operations and assets for these segments are as follows:

19. Segmented Information (continued):

Operational Segments (continued):

	Three months ended September 30, 2011							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Energy sales	$ 19,197	$ 12,755	$ 31,952	$ -	$ -	$ -	$ -	$ 31,952
Utility energy sales and distribution	-	-	-	-	16,663	16,663	-	16,663
Waste disposal fees	-	4,074	4,074	-	-	-	-	4,074
Water reclamation and distribution	-	-	-	12,257	-	12,257	-	12,257
Other revenue	746	356	1,102	-	-	-	-	1,102
Total revenue	19,943	17,185	37,128	12,257	16,663	28,920	-	66,048
Operating expenses	6,658	11,035	17,693	5,789	13,401	19,190	(1)	36,882
	13,285	6,150	19,435	6,468	3,262	9,730	1	29,166
Other administration costs	(1,575)	(611)	(2,186)	(293)	(197)	(490)	(2,078)	(4,754)
Foreign exchange loss	-	-	-	-	-	-	1,149	1,149
Interest expense	(2,195)	(496)	(2,691)	(1,381)	(1,147)	(2,528)	(2,210)	(7,429)
Interest, dividend and other income	510	86	596	78	-	78	732	1,406
Loss on derivative financial instruments	-	-	-	-	-	-	(3,754)	(3,754)
Depreciation of property, plant and equipment	(4,132)	(2,676)	(6,808)	(1,051)	(1,688)	(2,739)	-	(9,547)
Amortization of intangible assets	(672)	(681)	(1,353)	(174)	-	(174)	-	(1,527)
Acquisition costs	-	-	-	-	(772)	(772)	-	(772)
Earnings / (loss) before income taxes	$ 5,221	$ 1,772	$ 6,993	$ 3,647	$ (542)	$ 3,105	$ (6,160)	$ 3,938
Property, plant and equipment	$ 421,291	154,591	575,882	214,310	160,632	374,942	769	951,593
Intangible assets	26,539	21,432	47,971	23,180	-	23,180	-	71,151
Total assets	474,295	198,895	673,190	262,874	193,990	456,864	133,079	1,263,133
Capital expenditures	16,855	8,981	25,836	1,225	2,433	3,658	(18)	29,476
Acquisition of operating entities	-	-	-	904	(1,036)	(132)	-	(132)

19. Segmented Information (continued):

Operational Segments (continued):

	Nine months ended September 30, 2011							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Energy sales	$ 63,750	$ 36,083	$ 99,833	$ -	$ -	$ -	$ -	$ 99,833
Utility energy sales and distribution	-	-	-	-	56,082	56,082	-	56,082
Waste disposal fees	-	12,360	12,360	-	-	-	-	12,360
Water reclamation and distribution	-	-	-	33,523	-	33,523	-	33,523
Other revenue	1,974	811	2,785	-	-	-	-	2,785
Total revenue	65,724	49,254	114,978	33,523	56,082	89,605	-	204,583
Operating expenses	21,207	33,342	54,549	16,681	43,781	60,462	(1)	115,010
	44,517	15,912	60,429	16,842	12,301	29,143	1	89,573
Other administration costs	(4,370)	(1,602)	(5,972)	(524)	(584)	(1,108)	(5,606)	(12,686)
Foreign exchange loss	-	-	-	-	-	-	1,051	1,051
Interest expense	(6,038)	(1,121)	(7,159)	(3,730)	(3,363)	(7,093)	(8,618)	(22,870)
Interest, dividend and other income	1,530	69	1,599	264	-	264	2,197	4,060
Loss on derivative financial instruments	(1,068)	-	(1,068)	-	-	-	(3,217)	(4,285)
Depreciation of property, plant and equipment	(12,608)	(8,073)	(20,681)	(5,690)	(2,834)	(8,524)	-	(29,205)
Amortization of intangible assets	(2,337)	(2,043)	(4,380)	(510)	-	(510)	-	(4,890)
Acquisition costs	-	-	-	-	(1,786)	(1,786)	-	(1,786)
Earnings / (loss) before income taxes	$ 19,626	$ 3,142	$ 22,768	$ 6,652	$ 3,734	$ 10,386	$ (14,192)	$ 18,962
Property, plant and equipment	$ 421,291	154,591	575,882	214,310	160,632	374,942	769	951,593
Intangible assets	26,539	21,432	47,971	23,180	-	23,180	-	71,151
Total assets	474,295	198,895	673,190	262,874	193,990	456,864	133,079	1,263,133
Capital expenditures	18,876	9,072	27,948	6,292	5,413	11,705	258	39,911
Acquisition of operating entities	-	-	-	904	97,322	98,226	-	98,226

19. Segmented Information (continued):

Operational Segments (continued):

	Three months ended September 30, 2010							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Energy sales	$ 16,058	$ 13,708	$ 29,766	$ -	$ -	$ -	$ -	$ 29,766
Utility energy sales and distribution	-	-	-	-	-	-	-	-
Waste disposal fees	-	3,868	3,868	-	-	-	-	3,868
Water reclamation and distribution	-	-	-	10,249	-	10,249	-	10,249
Other revenue	562	354	916	-	-	-	-	916
Total revenue	16,620	17,930	34,550	10,249	-	10,249	-	44,799
Operating expenses	7,863	10,691	18,554	5,921	-	5,921	-	24,475
	8,757	7,239	15,996	4,328	-	4,328	-	20,324
Other administration costs	(1,434)	(663)	(2,097)	189	-	189	(1,947)	(3,855)
Foreign exchange loss	-	-	-	-	-	-	840	840
Interest expense	(1,853)	(242)	(2,095)	(405)	-	(405)	(3,787)	(6,287)
Interest, dividend and other income	230	19	249	57	-	57	937	1,243
Gain / (loss) on derivative financial instruments	(2,264)	-	(2,264)	-	-	-	1,459	(805)
Depreciation of property, plant and equipment	(4,488)	(2,808)	(7,296)	(1,787)	-	(1,787)	-	(9,083)
Amortization of intangible assets	(1,756)	(695)	(2,451)	(172)	-	(172)	-	(2,623)
Acquisition costs	-	-	-	-	-	-	(332)	(332)
Earnings / (loss) before income taxes	$ (2,808)	$ 2,850	$ 42	$ 2,210	$ -	$ 2,210	$ (2,830)	$ (578)
Property, plant and equipment	$ 395,137	$ 177,061	$ 572,198	$ 169,313	$ -	$ 169,313	$ 244	741,755
Intangible assets	30,096	24,038	54,134	23,473	-	23,473	-	77,607
Total assets	452,946	222,770	675,716	205,204	-	205,204	91,916	972,836
Capital expenditures	409	1,227	1,636	1,024	-	1,024	2	2,662
Acquisition of operating entities	-	-	-	-	692	692	-	692

19. Segmented Information (continued):

Operational Segments (continued):

	Nine months ended September 30, 2010							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Energy sales	$ 58,250	$ 38,354	$ 96,604	$ -	$ -	$ -	$ -	$ 96,604
Utility energy sales and distribution	-	-	-	-	-	-	-	-
Waste disposal fees	-	4,875	4,875	-	-	-	-	4,875
Water reclamation and distribution	-	-	-	28,002	-	28,002	-	28,002
Other revenue	1,559	898	2,457	-	-	-	-	2,457
Total revenue	59,809	44,127	103,936	28,002	-	28,002	-	131,938
Operating expenses	22,037	32,833	54,870	16,829	-	16,829	-	71,699
	37,772	11,294	49,066	11,173	-	11,173	-	60,239
Other administration costs	(3,262)	(1,516)	(4,778)	(1,075)	-	(1,075)	(3,907)	(9,760)
Foreign exchange loss	-	-	-	-	-	-	474	474
Interest expense	(5,374)	(657)	(6,031)	(1,309)	-	(1,309)	(10,978)	(18,318)
Interest, dividend and other income	632	537	1,169	68	-	68	2,614	3,851
Gain / (loss) on derivative financial instruments	(4,532)	-	(4,532)	-	-	-	1,587	(2,945)
Depreciation of property, plant and equipment	(13,392)	(8,374)	(21,766)	(5,314)	-	(5,314)	-	(27,080)
Amortization of intangible assets	(4,927)	(2,084)	(7,011)	(508)	-	(508)	-	(7,519)
Acquisition costs	-	-	-	-	-	-	(684)	(684)
Earnings / (loss) before income taxes	$ 6,917	$ (800)	$ 6,117	$ 3,035	$ -	$ 3,035	$ (10,894)	$ (1,742)
Property, plant and equipment	$ 395,137	$ 177,061	$ 572,198	$ 169,313	$ -	$ 169,313	$ 244	$ 741,755
Intangible assets	30,096	24,038	54,134	23,473	-	23,473	-	77,607
Total assets	452,946	222,770	675,716	205,204	-	205,204	91,916	972,836
Capital expenditures	1,352	11,147	12,499	2,060	-	2,060	79	14,638
Acquisition of operating entities	40,281	-	40,281	2,121	692	2,813	-	43,094

Within APCo, a significant portion of energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2011 or 2010: Hydro Québec 18% (2010 - 14%), Manitoba Hydro 18%, (2010 – 16%), Sanger 12% (2010 - 12%), and AES 14% (2010 - 11%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

19. Segmented Information (continued):

Operational Segments (continued):

Geographic Segments

APUC 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 ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Revenue				
Canada	$ 20,341	$ 19,797	$ 65,149	$ 52,324
United States	$ 45,707	$ 25,002	$ 139,434	$ 79,614
	$ 66,048	$ 44,799	$ 204,583	$ 131,938

	September 30, 2011	December 31, 2010
Property, plant and equipment		
Canada	$ 468,268	$ 464,782
United States	$ 483,325	$ 296,957
	$ 951,593	$ 761,739
Intangible assets		
Canada	$ 40,455	$ 43,305
United States	$ 30,696	$ 30,581
	$ 71,151	$ 73,886
Other assets		
Canada	$ 1,901	$ 1, 414
United States	$ -	$ 1,940
	$ 1,901	$ 3,354

Revenues are attributed to the two countries based on the location of the related generating and utility facilities.

20. Financial instruments

(a) Fair Value of financial instruments

	September 30, 2011 Carrying amount	September 30, 2011 Fair value	December 31, 2010 Carrying amount	December 31, 2010 Fair value
Cash	$ 15,525	$ 15,525	$ 4,749	$ 4,749
Short-term investments	5,025	5,025	3,674	3,674
Accounts receivable and due from related parties	35,355	35,355	26,594	26,594
Restricted cash	3,550	3,550	3,563	3,563
Energy forward purchase	296	296	-	-
Notes receivables	24,705	24,705	18,744	18,744
Total financial assets	$ 84,456	$ 84,456	$ 57,324	$ 57,324

20. Financial instruments (continued):

(a) Fair Value of financial instruments (continued):

		September 30, 2011 Carrying amount		Fair value		December 31, 2010 Carrying amount		Fair value
Accounts payable and due to related parties	$	5,807	$	5,807	$	4,409	$	4,409
Accrued liabilities		47,420		47,420		28,839		28,839
Dividends payable		8,341		8,341		5,721		5,721
Long-term liabilities		349,794		354,136		259,897		262,117
Other long-term liabilities		89,850		89,850		66,940		66,940
Convertible debentures		122,427		147,833		181,759		216,769
Interest swaps		7,650		7,650		5,440		5,440
Energy forward purchase		-		-		378		378
Foreign exchange contracts		-		-		45		45
Total financial liabilities	$	631,289	$	661,037	$	553,428	$	590,658

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value at September 30, 2011 and December 31, 2010 due to the short-term maturity of these instruments.

Long term investments and notes receivable include equity instruments and notes receivable. The equity instruments do not have a quoted market price in an active market, and fair value cannot be reliably measured. Notes receivable fair values have been determined using a discounted cash flow method, using estimated current market rates for similar instruments adjusted for estimated credit risk as determined by management. Such estimate is significantly influenced by unobservable data and therefore this fair value is subject to estimation risk.

APUC has long-term liabilities and convertible debentures at fixed interest rates and variable rates. The estimated fair value is calculated using the current interest rates.

Advances in aid of construction included in other long-term liabilities (note – 1 (l)) do not bear interest and the amount to be repaid is subject to uncertainty and estimation. The fair value is considered to approximate the book value.

Fair value estimates are made at a specific point in time, using available information about the financial instrument. These estimates are subjective in nature and often cannot be determined with precision.

(b) Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities accounted for at fair value at September 30, 2011 are as follows:

		Level 1		Level 2		Level 3		Total
Derivative assets:								
Energy forward purchase	$	-	$	296	$	-	$	296
Derivative liabilities:								
Energy hedge – AES	$	-	$	(207)	$	-	$	(207)
Interest swap –APCo		-		(7,443)		-		(7,443)
	$	-	$	(7,354)	$	-	$	(7,354)

The Company's accounting policy is to recognize transfers between levels of the fair value hierarchy on the date of the event or change in circumstances that caused the transfer. There was no transfer into or out of level 1, level 2 or lever 3 during the three months ended September 30, 2011. No assets or liabilities are measured at fair value on a recurring basis using unobservable inputs (Level 3).

20. Financial instruments (continued):

(c) Effect of derivative instruments on the Consolidated Statement of Operations

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

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Change in unrealized loss/(gain) on derivative financial instruments:				
Foreign exchange contracts	$ -	$ (870)	$ (45)	$ (727)
Interest rate swaps	2,112	345	2,004	(454)
Energy forward purchase contracts	974	(534)	(429)	(2,448)
Total change in unrealized loss/(gain) on derivative financial instruments	$ 3,086	$ (1,059)	$ 1,530	$ (3,629)
Realized loss/(gain) on derivative financial instruments:				
Foreign exchange contracts	$ -	$ (167)	$ 691	$ (592)
Interest rate swaps	539	1,453	1,607	4,635
Energy forward purchase contracts	129	578	457	2,531
Total realized loss on derivative financial instruments	$ 668	$ 1,864	$ 2,755	$ 6,574
Loss on derivative financial instruments	$ 3,754	$ 805	$ 4,285	$ 2,945

(d) Risk Management

In the normal course of business, the Company is exposed to financial risks that potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks to the extent possible on a cost effective basis. Derivative financial instruments are used to manage certain exposures to fluctuations in exchange rates, interest rates and commodity prices. The Company does not enter into derivative financial agreements for speculative purposes.

This note provides disclosures relating to the nature and extent of the Company's exposure to risks arising from financial instruments, including credit risk, liquidity risk, foreign currency risk and interest rate risk, and how the Company manages those risks.

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents and accounts receivable. The Company limits its exposure to credit risk with respect to cash equivalents by maintaining minimal cash balances and ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better.

The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from Power Generation 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 Liberty Utilities business unit which consists of electrical distribution and of water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of US$12,030 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

As at September 30, 2011, the Company's exposure to credit risk measured in Canadian dollars for these financial instruments was as follows:

	Canadian	US
Cash and cash equivalents	$ 2,797	$ 12,728
Short term investments	834	4,191
Accounts receivable & due to related parties	10,273	25,630
Allowance for Doubtful Accounts	(340)	(208)
Notes Receivable	22,586	2,119
	$ 36,150	$ 44,460

There are no material past due amounts in accounts receivable.

20. Financial instruments (continued):

(d) Risk Management (continued):

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company'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. As of September 30, 2011, in addition to cash on hand of $15,525 the Company had $67,925 available to be drawn on its senior debt facility. The senior credit facility contains covenants which may limit amounts available to be drawn. The Company`s liabilities mature as follows:

	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years	Total
Long term debt obligations	$ 1,304	$ 3,466	$ 16,180	$ 328,844	$ 349,794
Convertible Debentures	-	-	-	122,427	122,427
Interest on long term debt	29,652	57,649	54,244	133,647	275,192
Accounts Payable and due to related parties	5,807	-	-	-	5,807
Accrued liabilities	47,420	-	-	-	47,420
Derivative financial instruments:					
Interest Rate Swaps	2,480	3,840	1,330	-	7,650
Lease Payments	247	242	80	-	569
Other obligations	1,236	516	516	8,186	10,454
Total obligations	$ 88,146	$ 65,713	$ 72,350	$ 593,104	$ 819,313

Foreign Currency Risk

The Company primarily uses U.S. dollar denominated debt to manage its foreign currency risk from its U.S. operations.

At September 30, 2011, the Company had no forward foreign exchange contracts. As at December 31, 2010, APUC had outstanding foreign exchange forward contracts to sell US$3,000 at an average rate of $1.00 and having a fair value liability of $45.

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility as well as interest earned on its cash on hand. The Company has performed sensitivity analysis on interest rate risk at September 30, 2011 to determine how a change in interest rates would impact equity and net earnings.

Senior credit facility

The Company's senior debt facility has a balance of $12,000 as at September 30, 2011. Assuming the current level of borrowings, a 1% change in the variable rate charged would impact interest expense by $30 during the three months ended September 30, 2011.

Interest rate swap

In 2006 the Company entered into a fixed for floating interest rate swap related to a notional debt of approximately $67.8 Million. This swap arrangement requires the payment of a fixed rate of interest by the Company in exchange for receipt of a variable rate of interest that mirrors the underlying notional debt's interest payment schedule. At September 30, 2011, the fair value of the interest rate swap was a net liability of $7,650 (December 31, 2010 - $5,440). APUC has elected not to use hedge accounting for the swap and records the fair value of the swap on the consolidated balance sheets. Any gain or loss in fair value is recognized in the consolidated statements of operations.

Sanger

The Company's project debt at the Sanger facility has a balance of U.S. $19,200 as at September 30, 2011. Assuming the current level of borrowings, a 1% change in the variable interest rate charged would impact interest expense by U.S. $48 during the three months ended September 30, 2011. This analysis assumes that all other variables, in particular foreign currency rates, remain constant.

Market Risk

APUC provides energy requirements to various customers under contract at fixed rates. While the Tinker Assets are expected to provide a portion of the energy required to service these customers, APUC anticipates having to purchase a portion of its energy requirements at the ISO NE spot rates to supplement self-generated energy.

20. Financial instruments (continued):

(d) Risk Management (continued):

APUC anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy.

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In January 2011, APUC entered into electricity derivative contracts with Nextera ("counterparty") for a term ending February 2014, these are fixed-for-floating swaps whereby APUC agrees with the counterparty to cash settle the difference between the floating or indexed price and the fixed price on a notional quantity 182,655 MW-hrs of energy over the remainder of the contact term at an average rate of approximately $51.87 per MW-hr. The estimated fair value of these forward energy hedge contracts at September 30, 2011 was a net asset of $296 (December 31,2010 - $0).

21. Subsequent events

On October 27, 2011, APUC completed a public offering of 15,100,000 common shares at a price of $5.65 per share for gross proceeds of approximately $85,300. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

22. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year, including certain reclassifications required to conform to U.S. GAAP.

Notes

Notes

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Christopher J. Ball – Executive Vice President, Corpfinance International Limited
Chris Huskilson – President and Chief Executive Officer, Emera Inc.
Chris Jarratt – Vice Chairman, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
George Steeves – Principal, True North Energy

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