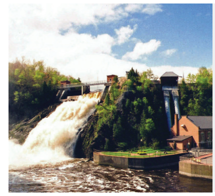
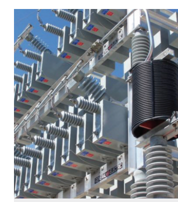
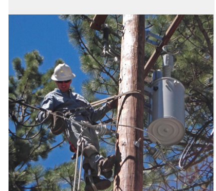



2012 Third Quarter Report






Algonquin Power & Utilities Corp.

Interim Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC" or the "Company") 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, 2012. 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, 2012 and 2011. 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, 2012.

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. In addition, such statements are made based on information available and expectations as of the date of this MD&A and such expectations may change after this date. APUC reviews material forward-looking information it has presented, not less frequently than 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"), "adjusted funds from operations", "per share cash provided by adjusted funds from operations" 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", "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations" 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, "adjusted funds from operations", "per share cash provided by adjusted funds from operations" and "per share cash provided by operating activities" can be found throughout this MD&A.

Overview and Business Strategy

APUC is incorporated under the *Canada Business Corporations Act*. APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings. APUC targets to deliver annualized per share earnings and cash flow growth of more than 5%.

APUC's current quarterly dividend to shareholders is $0.0775 per share or $0.31 per share per annum. 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 and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") with dividend levels being 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 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.

APUC conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation assets; and Liberty Utilities Co. ("Liberty Utilities"), a diversified rate regulated utility which owns and operates a portfolio of North American electric, natural gas and water distribution utility systems.

Algonquin Power Co.

APCo generates and sells electrical energy produced by its diverse portfolio of renewable power generation and clean thermal power generation facilities located across North America. APCo seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

APCo owns or has interests in hydroelectric facilities with a combined generating capacity of approximately 170 MW. APCo also owns or has interests in wind powered generating stations with a combined generating capacity of 170 MW. Approximately 84% of the electrical output from the hydroelectric and wind generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 15.5 years.

APCo owns or has interests in thermal energy facilities with approximately 341 MW of installed generating capacity. Approximately 95% of the electrical output from the owned thermal facilities is sold pursuant to long term Power Purchase Agreements ("PPA") with major utilities and which have a weighted average remaining contract life of 7.0 years.

Liberty Utilities Co.

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services. Liberty Utilities provides safe, high quality and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities delivers continued growth in earnings through accretive acquisition of additional utility systems.

The utility systems owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. To accommodate the current and expected future growth of the business, Liberty Utilities has elected to report the performance of its utility operations by geographic region rather than by line of business. Consequently, the results of Liberty Utilities businesses are reported in the content of three regions – West, Central, and East.

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility serves approximately 47,000 active electric connections in the State of California. These distribution and related generation assets (the "California Utility") are currently owned in partnership with Emera Inc. ("Emera"). Regulatory approval has been received for Liberty Utilities to acquire Emera's partnership interest which is expected to occur in the fourth quarter of 2012. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 66,000 water and wastewater connections located in the State of Arizona. These utilities systems, previously reported in the Liberty Utilities (South) region, have now been combined with Liberty Utilities (West) for reporting purposes, effective July 1, 2012.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 80,400 active natural gas connections located in the States of Illinois, Missouri, and Iowa and the regulated water distribution and wastewater collection utilities serve approximately 11,500 water and wastewater customers located in the States of Illinois, Missouri, and Texas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire; namely, Granite State Electric Company ("Granite State") which provides regulated local electrical utility services to approximately 43,000 active electric connections; and EnergyNorth which provides regulated local gas distribution utility services to approximately 85,000 active natural gas connections.

Major Highlights

Corporate Highlights

<u>Issuance of $120M Preferred Shares</u>

On November 9, 2012, APUC issued 4.8 million cumulative rate reset preferred shares, Series A (the "Series A Shares") at a price of $25 per share, for aggregate gross proceeds of $120 million. The shares will yield 4.5% per cent annually for the initial six-year period ending on December 31, 2018. The preferred shares have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively. The proceeds of the offering will be used to partially fund the acquisition of the US wind portfolio assets expected to close late in 2012.

<u>Dividend Increased to $0.31 per Common Share Annually</u>

APUC has completed several acquisitions and has announced a number of other initiatives that have raised the growth profile for APUC's earnings and cash flows which in turn supports an increase in the dividend to shareholders. These growth initiatives, discussed in more detail below, include the acquisition of natural gas and electric utilities as well as the development and acquisition of new wind power generating projects. As a result, on August 9, 2012, the Board approved a further dividend increase of $0.03 annually bringing the total annual dividend to $0.31, paid quarterly at the rate of $0.0775 per common share.

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

<u>Strengthened Balance Sheet</u>

<u>Emera Subscription Receipts</u>

During the nine month period ended September 30, 2012, APUC issued a total of 17.43 million shares for cash proceeds of $105 million pursuant to exercise of subscription receipts issued to Emera in contemplation of certain previously announced transactions as outlined below.

On May 14, 2012, in connection with the acquisitions of Granite State and EnergyNorth, APUC issued 12.0 million common shares at a price of $5.00 per share to Emera pursuant to a subscription receipt agreement. The $60.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions. On June 29, 2012, in connection with the acquisition of the 50MW Sandy Ridge wind farm from Gamesa USA, APUC received $15.0 million relating to 2.6 million subscription receipts representing a price of $5.74 per share.

On August 1, 2012, in connection with the acquisition of the Midwest Gas Utilities, APUC issued 6.98 million shares at a price of $6.45 per share to Emera pursuant to a subscription receipt agreement. The $45.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

As a result of the issuance of subscription receipts and the related conversion into common shares, as at November 14, 2012, Emera now owns 30.1 million APUC common shares representing approximately 17.8% of the total outstanding common shares of the Company. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

Conversion of Series 2A Convertible Debentures to Equity

On February 24, 2012 ("Series 2A Redemption Date"), APUC redeemed $57.0 million, representing the remaining issued and outstanding, Series 2A Debentures by issuing and delivering 9,836,520 APUC common shares. Between January 1, 2012 and the Series 2A Redemption Date, a principal amount of $2.9 million of Series 2A Debentures were converted into 485,998 common shares of APUC.

Liberty Utilities Highlights

New Hampshire Utility Acquisitions

On July 3, 2012, Liberty Utilities completed the acquisition of all issued and outstanding shares of Granite State and EnergyNorth, both from National Grid, for consideration of U.S. $285.0 million plus working capital and other closing adjustments for a total purchase price of U.S. $297.4 million.

Midwest Utility Acquisitions

On August 1, 2012, Liberty Utilities completed the acquisition of regulated natural gas distribution utility assets (the "Midwest Gas Utilities") located in Missouri, Iowa, and Illinois from Atmos for consideration of U.S. $123.9 million plus working capital and other closing adjustments for a total purchase price of U.S. $128.9 million.

U.S. $225 Million Private Placement

During the third quarter, Liberty Utilities completed a U.S. $225 million private placement debt financing. The financing was closed in two tranches contemporaneously with the closing of the above noted acquisitions. The notes are senior unsecured notes with an average life maturity of over ten years and a weighted average coupon of 4.38%. The notes have been assigned a rating of "BBB high" by DBRS Limited. Proceeds from the private placement were used to partially fund the New Hampshire and Midwest Gas Utilities acquisitions.

Agreement to acquire a Regulated Water Utility System

On July 20, 2012, Liberty Utilities entered into an agreement with United Waterworks Inc. to acquire all issued and outstanding shares of United Water Arkansas Inc. a regulated water distribution utility ("Arkansas Water") located in Pine Bluff, Arkansas serving approximately 17,300 customers. Total purchase price for Arkansas Water is approximately U.S. $28.6 million representing a 1.16x premium to net utility assets of U.S. $24.6 million and subject to certain working capital and other closing adjustments.

Subsequent to the end of the quarter, on November 7, 2012, Liberty Utilities and the staff of the Arkansas Public Service Commission (collectively "the Parties") jointly requested that the Commission allow the Parties to submit a joint negotiated settlement in lieu of filing additional testimony. The Settlement, together with a request to forego hearings is expected to be submitted to the Commission on November 14, 2012, which is expected to result in approval of the transaction in late 2012 or Q1 2013. Closing of the transaction is subject to certain conditions and is expected to occur in Q1 2013.

Agreement to acquire Regulated Gas Utility Systems

On August 8, 2012, Liberty Utilities entered into an agreement with Atmos to acquire certain regulated natural gas distribution utility systems (the "Georgia Utility") serving approximately 60,000 customers located in the State of Georgia. The total purchase price for the Georgia Utility is approximately U.S. $140.7 million representing a 1.1x premium to rate base of U.S. $128.1 million and is subject to certain working capital and other closing adjustments.

A procedural schedule in respect of the approval of the acquisition has been issued by the Georgia Public Service Commission which anticipates a final order to be received on February 19, 2013. Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in Q2 2013.

Expansion of Liberty Utilities Credit Facility

In Q1 2012, Liberty Utilities entered into an agreement for a senior unsecured revolving credit facility (the "Liberty Facility") with a three year term and a credit limit of U.S. $40 million. On July 3, 2012, with the closing of the Granite State and EnergyNorth acquisitions, the facility was increased to U.S. $100 million.

Algonquin Power Co. Highlights

Completion of Investment in U.S. Wind Projects

On March 9, 2012, APCo, entered into an agreement to acquire an interest in a portfolio of wind power projects in the United States being developed by Gamesa USA; the projects consist of three facilities - Sandy Ridge (50MW), Minonk (200MW) and Senate (150MW) (collectively, the "US Wind Farms"). The total consideration to be paid by APCo for a 58.75% interest in such wind projects is approximately U.S. $270.0 million.

On July 1, 2012, APCo acquired a 51% controlling interest in the 50 MW Sandy Ridge wind project for approximately U.S. $29.7 million. Subsequent to the end of the quarter, APCo acquired an additional 7.75% interest for U.S. $4.5 million bringing the total interest to 58.75% for total consideration of U.S. $34.2 million.

Closing of the investment in the Minonk (200 MW) and Senate (150 MW) facilities in Illinois and Texas, respectively, is expected to occur in late 2012 following commercial operation of the projects. Subsequent to the end of the quarter, APCo paid U.S. $11.6 million in relation to its ownership interest in the Senate and Minonk projects. This amount is the first payment towards the total purchase of the projects which will be made following their respective Commercial operation dates ("COD").

APCo Credit Facility

On May 31, 2012, APCo increased its senior revolving credit facility (the "APCo Facility") with its bank syndicate to $155 million.

2012 Nine month results from operations

Key Selected Nine Month Financial Information

(millions of dollars except per share information)	Nine months ended September 30 2012		2011
Revenue	$	**228.9**	$ 204.6
Adjusted EBITDA [1, 3]		**72.4**	81.0
Cash provided by operating activities		**45.9**	64.6
Adjusted funds from operations[1, 3]		**51.1**	57.5
Net earnings/(loss) attributable to Shareholders		**8.1**	31.9
Adjusted net earnings[1, 3]		**15.7**	34.9
Dividends declared to Shareholders		**34.7**	22.9
Weighted Average number of common shares outstanding		**154,378,090**	111,963,782
Per share			
Basic net earnings/(loss)	$	**0.05**	$ 0.29
Adjusted net earnings[1, 2, 3]	$	**0.11**	$ 0.31
Diluted net earnings/(loss)	$	**0.05**	$ 0.28
Cash provided by operating activities [1, 2, ,3]	$	**0.30**	$ 0.58
Adjusted funds from operations[1, 2, 3]	$	**0.33**	$ 0.51
Dividends declared to Shareholders	$	**0.22**	$ 0.19
Total assets		**1,967.1**	1,282.3
Long term liabilities[4]		**705.1**	455.0

1 APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations 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 adjusted net earnings, cash provided by operating activities and adjusted funds from operations 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.

4 Long term debt includes current and long term portion of debt and convertible debentures.

For the nine months ended September 30, 2012, APUC experienced an average U.S. exchange rate of approximately $1.001 as compared to $0.978 in the same period in 2011. 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.

For the nine months ended September 30, 2012, APUC reported total revenue of $228.9 million as compared to $204.6 million during the same period in 2011, an increase of $24.3 million or 12%. The major factors resulting in the increase in APUC revenue in the nine months ended September 30, 2012 as compared to the corresponding period in 2011 are set out as follows:

		Nine months ended September 30, 2012
		(Millions)
Comparative Prior Period Revenue	$	204.6
Significant Changes:		
Liberty Utilities (West) - Lower electricity sales to customers		(4.9)
Liberty Utilities (West) - Revenue increases primarily due to rate case approvals		0.4
Liberty Utilities (Central) – Revenue increase result of Midwest Gas Utilities acquisitions		5.4
Liberty Utilities (Central) - Revenue increases primarily due to late 2011 acquisitions		0.3
Liberty Utilities (East) – Gas revenue increase due to EnergyNorth acquisition		12.2
Liberty Utilities (East) – Electricity revenue increase due to Granite State acquisition		19.1
Revenue increase due to acquisition of Sandy Ridge wind farm		0.7
Effect of wind resource compared to comparable period in prior year		0.6
Revenue Increase from St Leon II expansion		0.7
Effect of hydrology resource compared to comparable period in prior year		(5.7)
Windsor Locks – Lower power sales and lower power rates		(7.5)
Sanger Facility – Offline for planned major maintenance		(2.4)
Impact of the stronger U.S. dollar		3.2
Tinker Hydro/AES - Increased demand for retail sales		2.9
Energy-from-Waste facility – Lower price per tonne for supplemental waste		(0.6)
Other		(0.1)
Current Period Revenue	$	228.9

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

Adjusted EBITDA in the nine months ended September 30, 2012 totalled $72.4 million as compared to $81.0 million during the same period in 2011, a decrease of $8.6 million. The decrease in Adjusted EBITDA was primarily due to lower results from operations primarily from lower hydrology in APCo's Renewable Energy Division, reduced energy sales at APCO's Windsor Locks facility, and lower customer demand at Liberty Utilities (West)'s electric distribution utility partially offset by revenues from increased wind resources at the St. Leon facility and the EnergyNorth, Granite State, and Midwest Gas Utilities acquisitions which closed in the third quarter. 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, 2012, net earnings attributable to Shareholders totalled $8.1 million as compared to $31.9 million during the same period in 2011, a decrease of $23.8 million. Net earnings per share totalled $0.05 for the nine months ended September 30, 2012, as compared to $0.29 during the same period in 2011.

The reduction in net earnings attributable to Shareholders for the nine months ended September 30, 2012 was due to $7.9 million decreased earnings from operating facilities, $4.6 million in increased acquisition costs and $1.6 million related to increased administration charges, $1.8 million in higher interest expense, $3.6 million increased depreciation and amortization expense and $0.3 million in increased write-downs of long lived assets, $2.1 million due to a stronger U.S. dollar, and $8.8 million in decreased recoveries of income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2011. These items were partially offset by $0.4 million in increased interest, dividend and other income, $4.1 million in reduced gains from derivative instruments, and $2.3 million in decreased allocations of earnings to non-controlling interests as compared to the same period in 2011.

During the nine months ended September 30, 2012, cash provided by operating activities totalled $45.9 million or $0.30 per share as compared to cash provided by operating activities of $64.6 million, or $0.58 per share during the same period in 2011. During the nine months ended September 30, 2012, adjusted funds from operations, a non-GAAP measure, totalled $51.1 million or $0.33 per share as compared to adjusted funds from operations of $57.5 million, or $0.51 per share during the same period in 2011. The change in adjusted funds from operations in the nine months ended September 30, 2012, is primarily due to reduced earnings from operations, partially offset by increased interest, dividend and other income as compared to the same period in 2011.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

2012 Three month results from operations

Key Selected Third Quarter Financial Information

(millions of dollars except per share information)		Three months ended September 30 2012		2011
Revenue	**$**	**99.0**	$	66.0
Adjusted EBITDA [1, 3]		**24.2**		25.9
Cash provided by operating activities		**17.5**		29.3
Adjusted funds from operations[1, 3]		**14.8**		20.0
Net earnings/(loss) attributable to Shareholders		**(0.2)**		19.6
Adjusted net earnings[1, 3]		**3.3**		21.5
Dividends declared to Shareholders		**13.1**		8.3
Weighted Average number of common shares outstanding		**168,977,490**		119,212,025
Per share				
Basic net earnings/(loss)	**$**	**0.00**	$	0.16
Adjusted net earnings[1, 2, 3]	**$**	**0.02**	$	0.18
Diluted net earnings/(loss)	**$**	**0.00**	$	0.16
Cash provided by operating activities [1, 2, ,3]	**$**	**0.10**	$	0.25
Adjusted funds from operations[1, 2, 3]	**$**	**0.09**	$	0.17
Dividends declared to Shareholders	**$**	**0.08**	$	0.07

1 APUC uses adjusted EBITDA, adjusted net earnings and adjusted funds from operations 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 adjusted net earnings, cash provided by operating activities and adjusted funds from operations 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.

For the three months ended September 30, 2012, APUC experienced an average U.S. exchange rate of approximately $0.995 as compared to $0.98 in the same period in 2011. 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.

For the three months ended September 30, 2012, APUC reported total revenue of $99.0 million as compared to $66.0 million during the same period in 2011, an increase of $33.0 million. The major factors resulting in the increase in APUC revenue in the three months ended September 30, 2012 as compared to the corresponding period in 2011 are set out as follows:

		Three months ended September 30, 2012 (Millions)
Comparative Prior Period Revenue	$	66.0
Significant Changes:		
Liberty Utilities (West) - Increased electricity sales to customers		0.3
Liberty Utilities (Central) – Revenue increase result of Midwest Gas Utilities acquisitions		5.4
Liberty Utilities (East) – Gas revenue increase result of EnergyNorth acquisition		12.2
Liberty Utilities (East) – Electricity revenue increase result of Granite State acquisition		19.1
Revenue increase due to acquisition of Sandy Ridge wind farm		0.7
Revenue Increase from St Leon II expansion		0.7
Effect of hydrology resource compared to comparable period in prior year		(3.2)
Windsor Locks – Lower power sales and lower power rates		(2.9)
Impact of the stronger U.S. dollar		0.5
Tinker Hydro/AES - Increased demand for retail sales		0.8
Other		0.3
Current Period Revenue	$	99.9

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

Adjusted EBITDA in the three months ended September 30, 2012 totalled $24.2 million as compared to $25.9 million during the same period in 2011, a decrease of $1.6 million. The decrease in Adjusted EBITDA was due to lower results from operations primarily as a result of lower hydrology in APCo's Renewable Energy Division, increased energy costs for APCO's energy sales group, and increased operating costs at Liberty Utilities (West)'s electric distribution utility partially offset by revenues from the EnergyNorth, Granite State, and Midwest Gas Utilities acquisitions which closed in the third quarter. 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, 2012, net loss attributable to Shareholders totalled $0.2 million as compared to net earnings attributable to Shareholders of $19.6 million during the same period in 2011, a decrease of $19.8 million. Net loss per share totalled $0.00 for the three months ended September 30, 2012, as compared to net earnings per share of $0.16 during the same period in 2011.

The reduction in net earnings attributable to Shareholders for the three months ended September 30, 2012 was due to $1.5 million in decreased earnings from operating facilities, $1.2 million in increased acquisition costs, $4.9 million in increased depreciation and amortization expense, $2.3 million in higher interest expense, $0.5 million in decreased interest, dividend and other income, $0.3 million in increased write-downs of long lived assets, $2.6 million due to a stronger U.S. dollar and $11.9 million in decreased recoveries of income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2011. These items were partially offset by $4.2 million due to increased gains on derivative instruments, $0.4 million related to decreased administration charges, and $0.6 million in decreased allocations of earnings to non-controlling interests as compared to the same period in 2011.

During the three months ended September 30, 2012, cash provided by operating activities totalled $17.5 million or $0.10 per share as compared to cash provided by operating activities of $29.3 million, or $0.25 per share during the same period in 2011. During the three months ended September 30, 2012, adjusted funds from operations totalled $14.8 million or $0.09 per share as compared to adjusted funds from operations of $20.0 million, or $0.17 per share during the same period in 2011. The change in adjusted funds from operations in the three months ended September 30, 2012, is primarily due to decreased earnings from operations, partially offset by increased interest, dividend and other income as compared to the same period in 2011.

Cash per share provided by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided by operating activities and per share adjusted funds from operations are not substitute measures of performance for earnings per share. Amounts represented by per share cash provided by operating activities and per share adjusted funds from operations do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Outlook

Overall APUC expects operational results for power generation in the fourth quarter to reflect long-term average resource conditions for hydroelctric and wind power generation.

APUC expects continuing modest customer growth throughout its regulated utilities service territories in 2012 and that its operations will meet APUC's expectations for the fourth quarter of 2012.

APUC's fourth quarter results will include the results of operations from Liberty Utilities' acquisition of Granite State and EnergyNorth, and APCo's acquisition of an interest in Sandy Ridge wind project. Additionally, the fourth quarter will be the first full quarter of operations for the Midwest Gas Utilities which closed on August 1, 2012. Combined, these acquisitions are expected to contribute $10.3 million in EBITDA in the fourth quarter. As the acquisition of interests in the Minonk and Senate wind projects are expected to close late in late 2012 following commercial operation of the projects, it is expected that these acquisitions will have a minimal effect on the fourth quarter results.

APCo: Renewable Energy Division

	Long Term Average Resource	Three months ended September 30 2012	2011	Long Term Average Resource	Nine months ended September 30 2012	2011
Performance (GW-hrs sold)						
Quebec Region	**63.9**	**46.1**	74.3	**205.9**	**193.4**	225.1
Ontario Region	**28.9**	**20.8**	23.8	**101.8**	**88.6**	92.3
Manitoba Region	**87.9**	**83.5**	80.8	**302.6**	**298.3**	267.0
Saskatchewan Region[1]	**20.5**	**16.9**	18.9	**64.7**	**62.1**	35.1
Pennsylvania Region[2]	**28.9**	**21.1**	-	**28.9**	**21.1**	-
New England Region	**7.2**	**2.7**	9.0	**43.1**	**28.4**	45.5
New York Region	**10.5**	**4.6**	15.1	**59.1**	**45.4**	66.6
Western Region	**23.8**	**22.6**	22.0	**52.4**	**52.9**	53.2
Maritime Region	**16.8**	**11.8**	51.5	**92.2**	**88.8**	101.9
Total	**288.4**	**230.1**	295.4	**950.7**	**879.0**	886.7

	Three months 2012	2011	Nine months 2012	2011
Revenue[3]	**(millions)**	(millions)	**(millions)**	(millions)
Energy sales	**$ 17.8**	$ 19.2	**$ 64.9**	$ 63.8
Less:				
Cost of Sales – Energy[4]	**(3.2)**	(0.7)	**(7.2)**	(3.0)
Net Energy Sales	**$ 14.6**	$ 18.5	**$ 57.7**	$ 60.8
Other Revenue	**0.4**	0.7	**1.2**	2.0
Total Net Revenue	**$ 15.0**	$ 19.2	**$ 58.9**	$ 62.8
Expenses				
Operating expenses	(6.2)	(6.0)	**(18.6)**	(18.2)
Interest and Other income	**0.1**	0.5	**1.5**	1.5
Division operating profit (including other income)	$ **8.9**	$ 13.7	**$ 41.8**	$ 46.11

1 APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility and has an option to acquire a 75% equity interest in the facility in 2016. The prior year 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 months of production.

2 Represents the operations of Sandy Ridge which was acquired in July 1, 2012.

3 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.

4 Cost of Sales – Energy consists of energy purchases by Algonquin Energy Services ("AES") which is resold to its retail and industrial customers. Under GAAP, in APUC's interim consolidated Financial Statements, these amounts are included in operating expenses.

2012 Nine Month Operating Results

For the nine months ended September 30, 2012, the Renewable Energy Division produced 879.0 GW-hrs of electricity, as compared to 886.7 GW-hrs produced in the same period in 2011, a decrease of 1%. The decreased generation is primarily due to reduced hydrology experienced during the second and third quarters of 2012 as compared to the comparable period in 2011, partially offset by the addition of production from the Sandy Ridge wind farm. This level of production in 2012 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 483,000 tons of CO_2 gas was prevented from entering the atmosphere in the nine months ended September 30, 2012.

During the nine months ended September 30, 2012, the division generated electricity equal to 93% of long-term projected average resources (wind and hydrology) as compared to 106% during the same period in 2011. For the nine months ended September 30, 2012, the Western region experienced resources slightly higher than long-term averages resources, whereas the Quebec, Manitoba, Saskatchewan, and Maritimes regions experienced slightly below long-term averages resources, with energy production consistent with resources approximately 1%-6% below long-term average resources. The Ontario, New England, Pennsylvania and New York regions experienced results approximately 13%-34% below long-term average expected generation.

For the nine months ended September 30, 2012, revenue from energy sales in the Renewable Energy Division totalled $64.9 million, as compared to $63.8 million during the same period in 2011. As the purchase of energy by the Energy Services Business is a significant revenue driver 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, 2012, net revenue from energy sales in the Renewable Energy Division totalled $57.7 million, as compared $60.8 million during the same period in 2011.

Revenue generated from APCo's Ontario, Quebec and Western regions decreased by $2.6 million primarily to a 9% overall decrease in hydrology, primarily in the Ontario region, slightly offset by $0.1 million due to an increase in weighted average energy rates, as compared to the same period in 2011. Revenue from APCo's New England and New York region facilities decreased $1.9 million due to decreased hydrology and by $0.7 million due to a decrease in weighted average energy rates of approximately 25%. Revenue from the Manitoba region increased $1.9 million primarily due to a stronger wind resource, partially offset by a decrease of $0.6 million due to decreased weighted average energy rates. Revenue from the new Pennsylvania region which accounts for Sandy Ridge, the first of three US Wind Project interests being acquired, produced revenue of $0.7 million. Revenue in the Maritime region decreased by 5% primarily driven by a $1.0 million in decreased customer demand offset by a $0.9 million increase in weighted average energy rates as compared to the same period in 2011. Revenue at AES increased 30% due to $1.5 million of increased customer demand and by a $1.5 million increase in weighted average energy rates. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine ($10.3 million), and merchant sales of production in excess of customer demand and other revenue ($3.3 million). The division reported increased revenue of $0.3 million from U.S. operations as a result of the stronger U.S. dollar as compared to the same period in 2011.

Red Lily I produced 62.1 GW-hrs of electricity for the nine months ended September 30, 2012. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges and is not reflected in revenues from energy sales. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily I for a direct 75% equity interest in

2016. For the nine months ended September 30, 2012, APCo earned fees and interest payments from Red Lily I in the total amount of $1.9 million.

For the nine months ended September 30, 2012, energy purchase costs by AES totalled $7.2 million. During this same period, AES purchased approximately 188.5 GW-hrs of energy at market and fixed rates averaging U.S. $61 per MW-hr. The division reported increased energy purchase costs of $0.3 million as a result of the stronger U.S. dollar as compared to the same period in 2011.

For the nine months ended September 30, 2012, operating expenses excluding energy purchases totalled $18.6 million, as compared to $18.2 million during the same period in 2011, an increase of $0.4 million or 2%. The increase was primarily impacted by a $0.5 million accrual for costs related to the Quebec water lease proceedings offset by $0.1 million in reduced repairs and maintenance costs as compared to the same period in 2011.

For the nine months ended September 30, 2012, interest and other income totalled $1.5 million, consistent with the same period in 2011. Interest and other income primarily consists of interest related to the senior and subordinated debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily I, as discussed above.

For the nine months ended September 30, 2012, the Renewable Energy Division's operating profit totalled $41.8 million, as compared to $46.1 million during the same period of 2011, representing a decrease of $4.3 million or 9%. For the nine months ended September 30, 2012, the Renewable Energy Division's operating profit did not meet APCo's expectations primarily due to reduced hydrology.

2012 Third Quarter Operating Results

For the quarter ended September 30, 2012, the Renewable Energy Division produced 230.1 GW-hrs of electricity, as compared to 295.4 GW-hrs produced in the same period in 2011, a decrease of 22%. The decreased generation is primarily due to reduced hydrology experienced in the quarter as compared to the comparable period in 2011. This level of production in 2012 represents sufficient renewable energy to supply the equivalent of 51,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 127,000 tons of CO_2 gas was prevented from entering the atmosphere in the third quarter of 2012.

During the quarter ended September 30, 2012, the division generated electricity equal to 80% of long-term projected average resources (wind and hydrology) as compared to 117% during the same period in 2011. In the third quarter of 2012, the Manitoba and Western regions experienced resources slightly lower than long-term averages resources, producing 5% below long-term average resources. The Quebec, Ontario, Saskatchewan, New England, New York, Pennsylvania and Maritimes regions produced below long-term averages resources, with the New England, and New York regions particularly affected with production approximately 60% below long-term average resources.

For the quarter ended September 30, 2012, revenue from energy sales in the Renewable Energy Division totalled $17.8 million, as compared to $19.2 million during the same period in 2011. As the purchase of energy by the Energy Services Business is a significant revenue driver 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, 2012, net revenue from energy sales in the Renewable Energy Division totalled $14.6 million, as compared $18.5 million during the same period in 2011.

Revenue generated from APCo's Ontario, Quebec and Western regions decreased by $2.3 million due to a 24% overall decrease in hydrology, primarily in the Ontario and Quebec regions, and $0.2 million due to a decrease in weighted average energy rates as compared to the same period in 2011. Revenue from APCo's New England and New York region decreased $0.6 million due to lower hydrology. Revenue from the Manitoba region increased $0.1 million primarily due to increased weighted average energy rates and an increase of $0.2 million due to increased wind resource. Revenue from the new Pennsylvania region which accounts for Sandy Ridge, the first of the three US Wind Project interests being acquired, produced revenue of $0.7 million. Revenue in the Maritime region decreased primarily due to a $0.5 million decrease in customer demand as compared to the same period in 2011. Revenue at AES increased 37% primarily due to $0.5 million of increased customer demand and a $0.7 million increase in weighted average energy rates. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine ($3.9 million), merchant sales of production in excess of customer demand and other revenue ($0.5 million). The division reported increased revenue of $0.1 million from U.S. operations as a result of the stronger U.S. dollar as compared to the same period in 2011.

Red Lily I produced 16.9 GW-hrs of electricity for the quarter ended September 30, 2012. APCo's economic return from its investment in Red Lily I currently comes in the form of interest payments, fees and other charges and is not reflected in revenues from energy sales. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily I for a direct 75% equity interest in 2016. For the quarter ended September 30, 2012, APCo earned fees and interest payments from Red Lily I in the total amount of $0.6 million.

For the quarter ended September 30, 2012, energy purchase costs by AES totalled $3.2 million. During the same period, AES purchased approximately 52.7 GW-hrs of energy at market and fixed rates averaging U.S. $61 per MW-hr. The division reported increased energy purchase costs of $0.1 million as a result of the stronger U.S. dollar as compared to the same period in 2011.

For the quarter ended September 30, 2012, operating expenses excluding energy purchases totalled $6.2 million, as compared to $6.0 million during the same period in 2011, an increase of $0.2 million or 3%. The increase was primarily impacted by $ 0.24 million in increased repairs and maintenance costs, as compared to the same period in 2011.

For the quarter ended September 30, 2012, interest and other income totalled $0.1 million, consistent with the same period in 2011. Interest and other income primarily consists of interest related to the senior and subordinated debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily I, as discussed above.

For the quarter ended September 30, 2012, the Renewable Energy Division's operating profit totalled $8.9 million, as compared to $13.7 million during the same period in 2011, representing a decrease of $4.8

million or 35%. For the quarter ended September 30, 2012, the Renewable Energy Division's operating profit did not meet APCo's expectations primarily due to reduced hydrology and wind resources.

APCo: Thermal Energy Division

	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
Performance (GW-hrs sold)	**74.0**	**124.4**	**227.8**	**367.2**
Performance ('000 tonnes of waste processed)	**41.9**	**41.2**	**127.2**	**124.7**
Performance (steam sales – billion lbs)	**292.2**	**277.9**	**963.4**	**901.0**
	(millions)	(millions)	**(millions)**	(millions)
Revenue				
Energy/steam sales	**$ 9.8**	$ 12.8	**$ 25.7**	$ 36.1
Less:				
Cost of Sales – Fuel *	**(3.1)**	(6.0)	**(10.2)**	(16.8)
Net Energy/Steam Sales Revenue	**$ 6.7**	$ 6.8	**$ 15.5**	$ 19.3
Waste disposal sales	**4.0**	4.1	**11.6**	12.4
Other revenue	**0.6**	0.4	**1.0**	0.8
Total net revenue	**$ 11.3**	$ 11.3	**$ 28.1**	$ 32.5
Expenses				
Operating expenses *	**(5.1)**	(5.1)	**(15.8)**	(16.5)
Interest and other income	**0.1**	0.1	**0.2**	0.1
Division operating profit				
(including interest and dividend income)	**$ 6.3**	$ 6.3	**$ 12.5**	$ 16.1

* Cost of Sales – Fuel consists of natural gas and fuel costs at the Sanger and Windsor Locks facilities.

APCo's Sanger and Windsor Locks generation facilities purchase natural gas from different suppliers and at prices based on different regional hubs. As a result, 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 shows 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.

2012 Nine Month Operating Results

For the nine months ended September 30, 2012, the Thermal Energy Division produced 227.8 GW-hrs of energy as compared to 367.2 GW-hrs of energy in the comparable period of 2011, primarily due to the planned outages at the Sanger and Windsor Locks facilities. During the nine months ended September 30, 2012, the business unit's total production decreased by 109.7 GW-hrs at the Windsor Locks facility and by 31.7 GW-hrs from the Sanger facility, as compared to the same period in 2011.

For the nine months ended September 30, 2012, the Energy-from-Waste ("EFW") facility processed approximately 127,200 tonnes of municipal solid waste as compared to 124,700 tonnes of municipal solid waste in the same period of 2011. The current level of production resulted in the diversion of approximately 94,600 tonnes of waste from municipal solid waste landfill sites in the first nine months of 2012.

For the nine months ended September 30, 2012, the Brampton Cogeneration Inc. ("BCI") and Windsor Locks facilities sold 963 billion lbs of steam as compared to 901 billion lbs of steam in the comparable period of 2011. During the nine months ended September 30, 2012, operations at the EFW facility generated 386 billion lbs of steam for the BCI facility as compared to 378 billion lbs of steam in the same period in 2011.

For the nine months ended September 30, 2012, energy / steam revenue in the Thermal Energy Division totalled $25.7 million, as compared to $36.1 million during the same period in 2011, a decrease of $10.4 million, or 29%. 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 an appropriate measure of the division's results. For the nine months ended September 30, 2012, net energy / steam sales revenue at the Thermal Energy Division totalled $15.5 million, as compared to $19.3 million during the same period in 2011, a decrease of $3.8 million, primarily due to the Sanger facility being offline from January to April 2012 and the Windsor Locks facility being offline for a large part of the second quarter of 2012.

The decreased revenue from energy / steam sales as compared to the same period in 2011, was primarily due to a decrease in revenue of $7.5 million from lower production at the Windsor Locks facility as a result of a planned shutdown in the second quarter of 2012 to install the new Solar Titan combustion gas turbine, and a decrease of $2.5 million in lower production at the Sanger facility as a result of being offline for a planned shutdown commencing in January 2012. Both planned shutdowns resulted in a $12.1 million decrease in energy / steam sales due to lower volume, partially offset by an increase of $2.1 million due to higher rates. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below compared to the same period in 2011.

Revenue from waste disposal sales for the nine months ended September 30, 2012 totalled $11.6 million, as compared to $12.4 million during the same period in 2011, a decline of $0.8 million or 6%. Revenue declined as the result of a greater level of supplemental waste processed by the facility for which lower average rates are charged pursuant to the existing waste disposal contract.

For the nine months ended September 30, 2012, fuel costs at Sanger and Windsor Locks totalled $10.2 million, as compared with $16.8 million in the same period in 2011, a decrease of $6.6 million. The overall natural gas expense at the Windsor Locks facility decreased $5.2 million or 37%, primarily the result of a 35% decrease in volume of natural gas consumed, in addition to a 3% decrease in the average landed cost of natural gas per MMBTU as compared to the same period in 2011. The average landed cost of natural gas at the Windsor Locks facility during the nine months ended September 30, 2012 was $4.74 per MMBTU. Natural gas expense at Sanger decreased $1.9 million or 52%, primarily the result of a 31% decrease in the volume of natural gas consumed in addition to a 31% decrease in the average landed cost of natural gas per MMBTU as compared to the same period in 2011. The average landed cost of natural gas at the Sanger facility during the nine months ended September 30, 2012 was U.S. $3.14 per MMBTU. The division reported increased fuel costs of $0.4 million as a result of the stronger U.S. dollar as compared to the same period in 2011.

For the nine months ended September 30, 2012, operating expenses, excluding fuel costs at EFW, Windsor Locks and Sanger, totalled $15.8 million, as compared to $16.5 million during the same period in 2011, a decrease of $0.7 million. The decrease in operating expenses was primarily impacted by $0.3 million at the EFW facility, primarily related to lower gas and maintenance costs, and $0.2 million due to planned shutdowns of the Sanger and Windsor Locks facilities, respectively, for portions of the first nine months of 2012.

For the nine months ended September 30, 2012, the Thermal Energy Division's operating profit totalled $12.5 million, as compared to $16.1 million during the same period in 2011, representing a decrease of $3.6 million or 22%. Operating profit in the Thermal Energy Division did not meet overall expectations for the nine months ended September 30, 2012.

2012 Third Quarter Operating Results

For the quarter ended September 30, 2012, the Thermal Energy Division produced 74.0 GW-hrs of energy as compared to 124.4 GW-hrs of energy in the comparable period of 2011. The decrease in energy production was primarily due to the outage at the Windsor Locks facility as compared to the same period in 2011.

The EFW facility processed approximately 41,900 tonnes of municipal solid waste as compared to 41,200 tonnes of municipal solid waste in the same period of 2011. The current level of production resulted in the diversion of approximately 31,400 tonnes of waste from municipal solid waste landfill sites in the third quarter of 2012.

For the quarter ended September 30, 2012, the BCI and Windsor Locks facilities sold 292 billion lbs of steam as compared to 278 billion lbs of steam in the comparable period of 2011. During the quarter ended September 30, 2012, operations at the EFW facility generated 122 billion lbs of steam for the BCI facility as compared to 129 billion lbs of steam in the same period in 2011.

For the quarter ended September 30, 2012, energy / steam revenue in the Thermal Energy Division totalled $9.8 million, as compared to $12.8 million during the same period in 2011, a decrease of $3.0 million, or 23%. 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 an appropriate measure of the division's results. For the quarter ended September 30, 2012, net energy / steam sales revenue at the Thermal Energy Division totalled $6.7 million, as compared to $6.8 million during the same period in 2011, a decrease of $0.1 million, primarily due the Windsor Locks facility being offline at the start of the quarter.

The decreased revenue from energy / steam sales was primarily due to a decrease of $3.6 million of lower production at the Windsor Locks facility as a result of unattractive market conditions resulting in lower sales to the energy market. This decrease was partially offset by $0.7 million in higher rates as compared to the same period in 2011. The Sanger facility experienced reduced revenue primarily as a result of lower fuel prices which resulted in a $0.4 million decrease in energy / steam sales due to lower rates. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below compared to the same period in 2011.

Revenue from waste disposal sales at the EFW facility for the quarter ended September 30, 2012 totalled $4.1 million which was consistent with the same period in 2011.

For the quarter ended September 30, 2012, fuel costs at Sanger and Windsor Locks totalled $3.1 million, as compared with $6.0 million in the same period in 2011, a decrease of $2.9 million. The overall natural gas expense at the Windsor Locks facility decreased $2.2 million or 47%, primarily the result of a 48% decrease in volume of natural gas consumed, offset by a 1% increase in the average landed cost of natural gas per MMBTU as compared to the same period in 2011. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $5.09 per MMBTU. Natural gas expense at Sanger decreased $0.3 million or 25%, primarily the result of a 26% decrease in the average landed cost of natural gas per MMBTU offset by a 1% increase in the volume of natural gas consumed as compared to the same period in 2011. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $3.37 per MMBTU. The division reported increased fuel costs of $0.2 million as a result of the stronger U.S. dollar as compared to the same period in 2011.

For the quarter ended September 30, 2012, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.1 million, which was consistent with the same period in 2011.

For the quarter ended September 30, 2012, the Thermal Energy Division's operating profit totalled $6.3 million, as compared to $6.3 million during the same period in 2011. Operating profit in the Thermal Energy Division met overall expectations for the quarter ended September 30, 2012.

APCo: Development Division

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, develop and construct other accretive expansion projects to maximize the value of APCo's existing facilities. The Development Division also creates value through accretive acquisitions of operating assets.

Projects Currently in Development

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	Commercial Operation	PPA Term	Production GW-hr
Chaplin Wind [1]	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$230.0	2014	20	247.0
Val Eo [1]	Quebec	24	$70.0	2015	20	66.0
Morse Wind [3, 4]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$70.0	2014	20	86.0
Cornwall Solar [1, 2]	Ontario	10	$45.0	2013	20	13.4
Total		**335**	**$840.0**			**1,225.4**

Notes:

1. PPA signed
2. FIT contract awarded
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").

Descriptions of selected projects and status updates for the current quarter are set out below. A complete description of all projects is provided in the APUC annual MD&A for the year ended December 31, 2011.

U.S. Wind Farm Acquisition

On March 9, 2012, an indirect subsidiary of APCo, entered into an agreement to acquire an interest in a portfolio of wind power projects in the United States which are being developed by Gamesa Energy USA, LLC ("Gamesa"). Total consideration to be paid by APCo for a 58.75% interest in these projects is approximately U.S. $270.0 million. The projects consist of three facilities - Sandy Ridge (50MW), Minonk (200MW) and Senate (150MW).

On July 1, 2012, APCo acquired a 51% controlling interest in the 50 MW Sandy Ridge wind project for approximately U.S. $29.7 million. Subsequent to the end of the quarter, APCo acquired an additional 7.75% interest for U.S. $4.5 million bringing the total interest to 58.75% for total consideration of U.S. $34.2 million.

The two remaining sites currently under construction by Gamesa are the following:

Minonk

The 200 MW Minonk wind project is located near Bloomington, Illinois and is currently under construction. The project is comprised of 100 Gamesa G90 units and is expected to produce 659 GW-hrs per annum with 86% of the energy being sold under a 10 year power sales agreement with JP Morgan Energy Ventures Corporation ("JPMVEC"), with the remaining energy and associated renewable energy credits sold on a merchant basis.

Senate

The 150 MW Senate wind project is approximately 70 miles northwest of Dallas / Fort Worth, Texas and is currently under construction. The project is comprised of 75 Gamesa G90 units and is expected to produce 520 GW-hrs per annum with 83% of the energy being sold under a 15 year power sales agreement with JPMVEC, with the remaining energy and associated renewable energy credits sold on a merchant basis.

Closing of the investment in the Minonk (200 MW) and Senate (150 MW) facilities in Illinois and Texas, respectively, is expected to occur in late 2012 following their commercial operation.

In addition to the agreement for the acquisition of an interest in the Sandy Ridge, Senate and Minonk wind farms, Gamesa and an indirect subsidiary of APCo have entered into a joint development agreement pursuant to which they will jointly pursue additional wind power development opportunities in the U.S. and Canada. Under the terms of the joint development agreement, the APCo entity will be provided visibility into Gamesa USA's pipeline of 2,700 MW of near and medium term wind power development opportunities in the U.S. and Gamesa USA will have the opportunity to work with the APCo entity to advance and expand APCo's 352 MW pipeline of contracted development projects.

Chaplin Wind

In the first quarter of 2012, APCo entered into a 25 year PPA with SaskPower for the development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan.

The project has a targeted COD of December, 2016. The facility is expected to be constructed at an estimated capital cost of $355 million and consist of approximately 77 multi-megawatt wind turbines. In its first full year of production, the project is expected to generate EBITDA of $37.5 million. The 25 year power purchase agreement features a rate escalation provision of 0.6% throughout the term of the agreement. The Project will take advantage of a favourable interconnection location by interconnecting with SaskPower's new P1S 230 kV transmission line from Swift Current to Moose Jaw and will be compliant with SaskPower's latest interconnection requirements.

Cornwall Solar

In the first quarter of 2012, APCo acquired all of the issued and outstanding shares of Cornwall Solar Inc. Cornwall Solar Inc. owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario (the "Cornwall Project"). In addition to the Cornwall Project, APCo has acquired an option to acquire 10 additional Ontario based solar projects which have submitted Feed in Tariff (FIT) applications for an additional 100MWac.

The Cornwall Project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MW-hr, resulting in expected initial annual revenues of approximately $6.2 million. The Cornwall Project contemplates the use of a ground-mounted PV array system, installed on two parcels of leased land totaling approximately 138 acres.

Following the completion of all regulatory submissions and approvals, construction of the project is expected to begin in 2013. The project's environmental assessment has now been deemed "administratively complete". COD is estimated in late 2013 with expected annual generation of approximately 13,400 MW-hrs.

Total capital cost of the project is targeted at approximately $45 million, including the consideration to be paid for the acquisition of the project. Funding for the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

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, Quebec. The environmental impact assessment for the project has now been submitted and is under review with provincial ministerial approval anticipated for Q3 2013.

Windsor Locks Repowering

The Windsor Locks facility is a 56 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 a co-located industrial customer (Alhstrom) pursuant to an energy services agreement ("ESA").

APCo has entered into an extension of the ESA with Ahlstrom which now continues until 2027. The installation of a new 14 MW Solar Titan combustion gas turbine was completed in July 2012 at a total net capital cost of U.S. $20.2 million and is now fully operational. APCo received a one-time non-recurring grant from the State of Connecticut for U.S. $6.5 million. APCo also believes that this project qualifies 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. $2.4 million. 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. With the new turbine now operational the existing Frame 6 is available as a peaking turbine to generate additional revenues.

APCo Outlook

The APCo Renewable Energy Division is expected to perform based on long-term average resource conditions for both wind and hydrology. In October, the Company's hydroelectric generating facility at Long Sault experienced an unplanned shut down. The shutdown is expected to decrease fourth quarter EBTIDA by approximately $0.9 million. The facility is expected to begin returning to service in the fourth quarter of 2012. New York and New England facilities are expected to perform below expectations due to lower power pricing compared to the previous year. The acquisition of an interest in Sandy Ridge wind project on July 1, 2012 is expected to generate additional revenues of approximately U.S. $1.4 million and EBITDA of U.S. $0.8 million in the fourth quarter of 2012. As the acquisition of the Minonk and Senate wind farms are expected to close late in the fourth quarter, they are not expected to have a significant impact on the fourth quarter results.

With respect to the Thermal Energy Division, the Sanger facility is expected to perform at a level in the fourth quarter of 2012 consistent with results experienced in 2011. After installation of the new Solar Titan combustion gas turbine in the third quarter of 2012, the Windsor Locks facility is better able to match production with demand from its industrial host under a PPA, limiting its exposure to lower market power pricing in New England.

With respect to the EFW facility, in October 2012, APCo received approval from the Ontario Ministry of Environment for an amendment to its environmental permits allowing the EFW facility to accept municipal, industrial, commercial and institutional waste from anywhere in Ontario. APCo has now entered into several waste supply agreements to ensure continued operation of the facility following the end of the waste supply contract with the Region of Peel on October 31, 2012. As a result of the lower pricing on such alternative waste supplies, the EBITDA from the EFW facility in the fourth quarter is expected to be approximately $1.5 million below the results experienced in fourth quarter of 2011.

Liberty Utilities

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services. To accommodate the current and expected future growth of the business, Liberty Utilities has elected to report the performance of its utility operations by geographic region rather than by line of business. Consequently, the results of Liberty Utilities businesses are reported in the content of three regions – West, Central, and East.

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems. The regulated electrical distribution utility serves approximately 47,000 active electric connections in the State of California. The Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 66,000 water and wastewater connections located in the State of Arizona. These utilities systems, previously reported in the Liberty Utilities (South) region, have now been combined with Liberty Utilities (West) for reporting purposes, effective July 1, 2012.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems. The regulated natural gas utilities serve approximately 80,400 active natural gas connections located in the states of Illinois, Missouri, and Iowa and the regulated water distribution and wastewater collection utilities serve approximately 11,500 water and wastewater customers located in the states of Illinois, Missouri, and Texas.

Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems located in the State of New Hampshire: namely, Granite State Electric Company ("Granite State") which provides regulated local electrical utility services to approximately 43,000 active electric connections; and EnergyNorth which provides regulated local gas distribution utility services to approximately 85,000 active natural gas connections.

For electricity and natural gas operations, Liberty Utilities reports active connections, exclusive of vacant connections rather than total connections. For water and wastewater operations, Liberty Utilities reports total connections, inclusive of vacant connections.

Liberty Utilities (West)

	Nine months ended September 30	
	2012	**2011**
Number of Active Electric Connections		
Residential	41,400	41,345
Commercial – Small	5,500	5,507
Commercial – Large	55	54
Total Active Electric Connections	**46,955**	**46,906**
Number of Water Connections		
Wastewater connections	31,500	30,800
Water distribution connections	34,550	33,800
Total Water Connections	**66,050**	**64,600**
Customer Usage (GW-hrs)		
Residential	201.4	219.0
Commercial – Small	107.3	123.3
Commercial – Large	81.9	92.5
Public Street and Highway Lighting	.8	.8
Total Customer Usage (GW-hrs)	**391.4**	**435.6**
Gallons Provided		
Wastewater treated (millions of gallons)	1,225	1,300
Water sold (millions of gallons)	3,825	3,960
Total Gallons Provided	**5,050**	**5,260**

Liberty Utilities (West) is comprised of Liberty Utilities operations in California and Arizona. As at September 30, 2012, Liberty Utilities (West) holds a 50.001% controlling interest in the California Utility.

Liberty Utilities (West)'s increase in water and wastewater connections during the period is primarily due to organic growth within the service territory.

For the nine months ended September 30, 2012, Liberty Utilities (West)'s electricity usage totalled 391.4 GW-hrs, as compared to 435.6 GW-hrs for the same period in 2011, a decrease of 44.2 GW-hrs or 10%. The decrease in usage was a result of milder winter and spring weather as compared with the colder weather experienced in the same period a year ago.

During the nine months ended September 30, 2012, Liberty Utilities (West) provided approximately 3.8 billion U.S. gallons of water to its customers, treated approximately 1.2 billion U.S. gallons of wastewater and sold approximately 250 million U.S. gallons of treated effluent.

		Nine months ended September 30				Nine months ended September 30	
		2012		2011		**2012**	2011
		U.S. $ (millions)		U.S. $ (millions)		**Can $ (millions)**	Can $ (millions)
Water Assets for regulatory purposes[1]		**178.7**		179.3			
Electricity Assets for regulatory purposes		**161.8**		153.2			
Revenue							
Utility electricity sales and distribution[2]	**$**	**52.5**	$	57.3	**$**	**52.5**	$ 56.1
Wastewater treatment		**14.0**		13.8		**14.0**	13.5
Water distribution		**14.2**		13.9		**14.2**	13.6
Other Revenue		**-**		0.3		**0.1**	-
Total Revenue	**$**	**80.7**	$	85.3	**$**	**80.8**	$ 83.2
Less:							
Cost of Sales – Electricity [2]		**(32.5)**		(33.8)		**(32.4)**	(33.0)
	$	**48.2**	$	51.5	**$**	**48.4**	$ 50.2
Expenses							
Operating expenses		**(26.3)**		(24.9)		**(26.3)**	(24.4)
Other income		**1.0**		0.3		**1.0**	0.3
Divisional operating profit	**$**	**22.9**	$	26.9	**$**	**23.1**	$ 26.1

1 Due to an accounting policy change related to the classification of "Advances in Aid of Construction", the previously reported number of $168.1 has been restated.

2 Represents 100% of investment in the California Utility.

2012 Nine Months Operating Results

Liberty Utilities (West) has investments in water assets for regulatory purposes of U.S. $178.7 million in the state of Arizona and electricity assets for regulatory purposes of U.S. $161.8 million in the state of California as at September 30, 2012, as compared to U.S. $179.3 million and U.S. $153.2 million, respectively as at September 30, 2011.

For the nine months ended September 30, 2012, Liberty Utilities (West)'s revenue totalled U.S. $80.7 million as compared to U.S. $85.3 million during the same period in 2011, a decrease of U.S. $4.5 million or 5%.

For the nine months ended September 30, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled U.S. $52.5 million as compared to U.S. $57.3 million during the same period in 2011, a decrease of U.S. $4.8 million or 8%. The decrease in revenues was a result of milder weather in the first half of 2012, compared with the colder winter weather experienced in the same period a year ago. The decreased utility electricity sales were primarily a result of U.S. $5.5 million due to a decrease in customer demand (approximately 10%), partially offset by an increase of U.S. $0.7 million (approximately 1%) due to weighted average electricity and general rates as compared to the same period in 2011. The purchase of electricity by Liberty Utilities (West) 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 utility electricity sales' (utility electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. For the nine months ended September 30, 2012, net utility electricity sales revenues for Liberty Utilities (West) were U.S. $20.0 million, as compared to U.S. $23.5 million during the same period in 2011.

For the nine months ended September 30, 2012, revenue from wastewater treatment totalled U.S. $14.0 million, as compared to U.S. $13.8 million during the same period in 2011, an increase of U.S. $0.2 million or 1%.

Revenue from water distribution totalled U.S. $14.2 million, as compared to U.S. $13.9 million during the same period in 2011, an increase of U.S. $0.3 million or 2%. The first nine months water distribution revenue was impacted by U.S. $0.2 million at the Litchfield Park ("LPSCo") facility primarily due to the increased residential, commercial and industrial revenue, U.S. $0.2 million at the Sierra Vista facilities due to the implementation of a rate increase, offset by a $0.1 million decrease at the remaining Liberty Utilities (West) water utilities.

For the nine months ended September 30, 2012, fuel and purchased power costs for Liberty Utilities (West)'s electric utility totalled U.S $32.5 million, as compared with U.S. $33.8 million for the same period in 2011. The overall electricity purchase expense decrease of U.S. $1.3 million was primarily the result of a 10% decrease in the volume of electricity purchased to meet customer demand, partially offset by a U.S. $2.0 million increase in weighted average electricity rates as compared to the same period in 2011.

For the nine months ended September 30, 2012, operating expenses totalled U.S. $26.4 million, as compared to U.S. $24.6 million during the same period in 2011. Operating expenses increased due to increased wages resulting from filling vacant positions that existed in the previous year, increased vegetation maintenance expense and increased insurance expense as compared to the same period in 2011.

For the nine months ended September 30, 2012, Liberty Utilities (West)'s operating profit was U.S. $23.0 million as compared to U.S. $27.2 million in the same period in 2011, a decrease of U.S. $4.2 million or 15%. Liberty Utilities (West)'s operating profit did not meet expectations for the nine months ended September 30, 2012, primarily as a result of lower customer electricity usage in the first half of the year resulting from warmer than expected winter and spring weather.

Measured in Canadian dollars, for the nine months ended September 30, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled $52.5 million, as compared to $56.1 million during the same period in 2011. As the purchase of electricity by Liberty Utilities (West) is a significant revenue driver and component of operating expenses, the division compares 'net utility electricity sales' (utility electricity sales revenue less electricity purchases) as a more appropriate measure of the division's results. For the nine months ended September 30, 2012, net utility electricity sales for Liberty Utilities (West) totalled $20.1 million, as compared to $23.1 million during the same period in 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2012, electricity purchases for Liberty Utilities (West) totalled $32.4 million, as compared to $33.0 million in the same period in 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2012, Liberty Utilities (West)'s revenue from water treatment and wastewater distribution totalled $28.2 million, as compared to $27.1 million during the same period in 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2012, operating expenses totalled $26.3 million, as compared to $24.4 million during the same period in 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2012, Liberty Utilities (West)'s operating profit totalled $23.1 million as compared to $26.1 million during the same period in 2011.

	Three months ended September 30	
	2012	**2011**
Customer Usage (GW-hrs)		
Residential	59.7	58.7
Commercial – Small	41.9	39.4
Commercial – Large	22.5	24.9
Public Street and Highway Lighting	0.3	0.3
Total Customer Usage (GW-hrs)	**124.4**	**123.3**
Gallons Provided		
Wastewater treated (millions of gallons)	400	400
Water sold (millions of gallons)	1,550	1,685
Total Gallons Provided	**1,950**	**2,085**

For the three months ended September 30, 2012, Liberty Utilities (West) electricity usage totalled 124.4 GW-hrs, as compared to 123.3 GW-hrs for the same period in 2011, an increase of 1.1 GW-hrs or 1%.

During the quarter ended September 30, 2012, Liberty Utilities (West) provided approximately 1.55 billion U.S. gallons of water to its customers, treated approximately 400 million U.S. gallons of wastewater and sold approximately 137 million U.S. gallons of treated effluent.

	Three months ended September 30		**Three months ended September 30**	
	2012	**2011**	**2012**	**2011**
	US $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Revenue				
Utility electricity sales and distribution*	**$ 17.3**	$ 17.0	**$ 17.2**	$ 16.7
Wastewater treatment	**4.7**	4.6	**4.7**	4.7
Water distribution	**5.4**	5.1	**5.3**	5.2
Other Revenue	**-**	-	**-**	-
	$ 27.4	$ 26.7	**$ 27.2**	$ 26.6
Less:				
Cost of Sales – Electricity	**(11.1)**	(10.2)	**(11.0)**	(10.0)
	$ 16.3	$ 16.5	**$ 16.2**	$ 16.6

	Three months ended September 30		Three months ended September 30	
	2012	2011	**2012**	2011
	US $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Expenses				
Operating expenses	**(8.7)**	(8.3)	**(8.6)**	(8.2)
Other income	**0.2**	0.1	**0.2**	0.1
Division operating profit*	**$ 7.8**	$ 8.3	**$ 7.8**	$ 8.5

* Represents 100% of investment in the California Utility.

2012 Third Quarter Operating Results

For the three months ended September 30, 2012, Liberty Utilities (West)'s revenue totalled U.S. $27.4 million as compared to U.S. $26.7 million during the same period in 2011, an increase of U.S. $0.7 million.

For the three months ended September 30, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled U.S. $17.3 million as compared to U.S. $17.0 million during the same period in 2011, an increase of U.S. $0.3 million or 2%. Revenue increased U.S. $0.2 million due to increased customer demand (approximately 1%) and increased U.S. $0.1 million (approximately 1%) due to increased weighted average electricity and general rates as compared to the same period in 2011. The purchase of electricity by Liberty Utilities (West) 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 utility electricity sales' (utility electricity sales revenue less electricity purchases) as a more appropriate measure of the division's results. For the three months ended September 30, 2012, net utility electricity sales for Liberty Utilities (West) totalled U.S. $6.2 million, as compared to U.S. $6.8 million during the same period in 2011.

For the three months ended September 30, 2012, revenue from wastewater treatment totalled U.S. $4.7 million, as compared to U.S. $4.6 million during the same period in 2011, an increase of U.S. $0.1 million or 2%.

Revenue from water distribution totalled U.S. $5.4 million, as compared to U.S. $5.1 million during the same period in 2011, an increase of U.S. $0.3 million or 6%. Third quarter water distribution revenue was impacted by U.S. $0.4 million increase at the Rio Rico facility primarily due to the increase of water revenue and usage, offset by a U.S. $0.1 million decrease at the LPSCo facility primarily due to a decrease in water usage.

For the three months ended September 30, 2012, fuel and purchased power costs for Liberty Utilities (West) totalled U.S $11.1 million, as compared with U.S. $10.2 million in the same period in 2011. The increase of U.S. $0.9 million was a result of a 1% increase in the volume of electricity used and an 8% increase in average cost of electricity as compared to the same period in 2011.

For the quarter ended September 30, 2012, operating expenses totalled U.S. $8.7 million, as compared to U.S. $8.3 million during the same period in 2011, an increase of U.S. $0.4 million or 5%. Operating expenses increased due to increased salary and wages, partially offset by reduced insurance, utilities and consumable expenses as compared to the same period in 2011.

For the three months ended September 30, 2012, Liberty Utilities (West)'s operating profit was U.S. $7.8 million as compared to U.S. $8.3 million in the same period in 2011, a decrease of U.S. $0.5 million or 6%. Liberty Utilities (West)'s operating profit did not meet expectations for the three months ended September 30, 2012.

Measured in Canadian dollars, for the quarter ended September 30, 2012, Liberty Utilities (West)'s revenue from utility electricity sales totalled $17.2 million, as compared to $16.7 million during the same period in 2011. As the purchase of electricity by Liberty Utilities (West) is a significant revenue driver and component of operating expenses, the division compares 'net utility electricity sales' (utility electricity sales revenue less electricity purchases) as a more appropriate measure of the division's results. For the quarter ended September 30, 2012, net utility electricity sales for Liberty Utilities (West) totalled $6.2 million, as compared to $6.7 million during the same period in 2011.

Measured in Canadian dollars, for the quarter ended September 30, 2012, electricity purchases for Liberty Utilities (West) totalled $11.0 million, as compared to $10.0 million in the same period in 2011.

Measured in Canadian dollars, for the quarter ended September 30, 2012, Liberty Utilities (West)'s revenue from water treatment and wastewater distribution totalled $10.0 million, as compared to $9.9 million during the same period in 2011.

Measured in Canadian dollars, for the quarter ended September 30, 2012, operating expenses totalled $8.6 million, as compared to $8.2 million in the same period in 2011

Measured in Canadian dollars, for the quarter ended September 30, 2012, Liberty Utilities (West)'s operating profit totalled $7.8 million as compared to $8.5 million in the same period in 2011.

Liberty Utilities (Central)

	Nine months ended September 30	
	2012	**2011**
Number of Active Natural Gas Connections		
Residential	70,700	-
Commercial	9,400	-
Industrial	55	-
Transportation	240	
Total Active Natural Gas Connections	**80,395**	-
Number of Water Connections		
Wastewater connections	6,000	5,750
Water distribution connections	5,500	4,250
Total Water Connections	**11,500**	**10,000**

	Nine months ended September 30	
	2012	2011
Customer Usage (MMBTU)		
Residential	146,800	-
Commercial	204,400	-
Industrial	47,600	-
Total Customer Usage (MMBTU)[1]	**398,800**	**-**
Gallons Provided		
Wastewater treated (millions of gallons)	275	200
Water sold (millions of gallons)	285	340
Total Gallons Provided	**560**	**540**

[1] Represents MMBTU since Aug 1, 2012 acquisition date

Liberty Utilities (Central) is comprised of Liberty Utilities' operations in Texas, Missouri, Illinois, and Iowa. Liberty Utilities (Central) acquired its natural gas distribution utilities on August 1, 2012 and accordingly there are no results for these utilities for the corresponding period in 2011.

Liberty Utilities (Central)'s increase in water and wastewater connections during the period is primarily due to acquisitions completed in late 2011.

From the acquisition date of August 1, 2012 to September 30, 2012, Liberty Utilities (Central) natural gas distribution sales totalled 1,337,100 MMBTU.

During the nine months ended September 30, 2012, Liberty Utilities (Central) provided approximately 285 million U.S. gallons of water to its customers, and treated approximately 275 million U.S. gallons of wastewater.

	Nine months ended September 30		Nine months ended September 30	
	2012	2011	2012	2011
	US $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Natural Gas Assets for regulatory purposes	**127.8**	-		
Water Assets for regulatory purposes	**23.0**	24.8		

	Nine months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
	US $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Revenue				
Utility natural gas sales and distribution [1]	**$ 5.5**	$ -	**$ 5.4**	$ -
Wastewater treatment	**4.2**	4.2	**4.3**	4.1
Water distribution	**2.7**	2.5	**2.7**	2.4
	12.4	6.7	**12.4**	6.5
Less:				
Cost of Sales – Natural Gas[1]	**(1.6)**	-	**(1.8)**	-
	$ 10.8	$ 6.7	**$ 10.6**	$ 6.5
Expenses				
Operating expenses	**(6.9)**	(3.2)	**(6.8)**	(3.1)
Divisional operating profit	**$ 3.9**	$ 3.5	**$ 3.8**	$ 3.4

1 Represents Natural Gas revenue and gas costs since Aug 1, 2012 acquisition date

2012 Nine Months Operating Results

Liberty Utilities (Central) has investments in natural gas assets for regulatory purposes of U.S. $127.8 million and water assets for regulatory purposes of U.S. $23.0 million as at September 30, 2012, as compared to U.S. $nil and U.S. $24.8 million, respectively as at September 30, 2011.

For the nine months ended September 30, 2012, Liberty Utilities (Central)'s revenue totalled U.S. $12.4 million as compared to U.S. $6.7 million during the same period in 2011, an increase of U.S. $5.7 million. The revenue increase can be mostly attributed to the addition of the natural gas distribution assets on August 1, 2012.

From the date of acquisition to September 30, 2012, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled U.S. $5.5 million. August and September were the first two months of the operation of the natural gas distribution assets for Liberty Utilities (Central). The purchase of natural gas by Liberty Utilities (Central) 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 utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. From the date of acquisition to September 30, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (West) totalled U.S. $3.9 million.

From the date of acquisition to September 30, 2012, natural gas purchases for Liberty Utilities (Central) totalled U.S $1.6 million.

For the nine months ended September 30, 2012, revenue from wastewater treatment totalled U.S. $4.2 million which was consistent with the same period in 2011.

Revenue from water distribution totalled U.S. $2.7 million, as compared to U.S. $2.5 million during the same period in 2011, an increase of U.S. $0.2 million or 8%.

For the nine months ended September 30, 2012, operating expenses, excluding natural gas purchases, totalled U.S. $6.9 million, as compared to U.S. $3.2 million during the same period in 2011. The increase in operating expenses can be mostly attributed to the addition of the natural gas distribution assets on August 1, 2012.

For the nine months ended September 30, 2012, Liberty Utilities (Central)'s operating profit was U.S. $3.9 million as compared to U.S. $3.5 million in the same period in 2011, an increase of U.S. $0.4 million or 11%.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled $5.4 million. As the purchase of natural gas by Liberty Utilities (Central) is a significant revenue driver and component of operating expenses, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. From the date of acquisition to September 30, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled $3.6 million.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, natural gas purchases for Liberty Utilities (Central) totalled $1.8 million.

Measured in Canadian dollars, for the nine months ended September 30, 2012, Liberty Utilities (Central)'s revenue from water treatment and wastewater distribution totalled $7.0 million, as compared to $6.5 million during the same period in 2011. Liberty Utilities (Central) reported a foreign exchange impact on revenue from water treatment and wastewater distribution of $0.3 million in the third quarter of 2012 as a result of the stronger U.S. dollar as compared to the same period in 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2012, operating expenses, excluding natural gas purchases totalled $6.8 million, as compared to $3.1 million during the same period in 2011.

Measured in Canadian dollars, for the nine months ended September 30, 2012, Liberty Utilities (Central)'s operating profit totalled $3.8 million as compared to $3.4 million in the same period in 2011.

	Three months ended September30	
	2012	**2011**
Customer Usage (MMBTU)		
Residential	146,800	-
Commercial	204,400	-
Industrial	47,600	-
Total Customer Usage (MMBTU) [1]	**398,800**	-
Gallons Provided		
Wastewater treated (millions of gallons)	100	75
Water sold (millions of gallons)	150	115
Total Gallons Provided	**250**	**190**

[1] Represents MMBTU since Aug 1, 2012 acquisition date

For the three months ended September 30, 2012, Liberty Utilities (Central) natural gas distribution sales totalled 1,337,100 MMBTU.

During the three months ended September 30, 2012, Liberty Utilities (Central) provided approximately 150 million U.S. gallons of water to its customers, and treated approximately 100 million U.S. gallons of wastewater.

	Three months ended September 30		Three months ended September 30	
	2012	**2011**	**2012**	**2011**
	U.S. $ (millions)	U.S. $ (millions)	**Can $ (millions)**	Can $ (millions)
Revenue				
Utility natural gas sales and distribution [1]	**$ 5.5**	$ -	**$ 5.4**	$ -
Wastewater treatment	**1.4**	1.4	**1.5**	1.2
Water distribution	**1.0**	1.4	**1.0**	1.2
Other Revenue	**-**	-	**-**	-
	7.9	2.8	**7.9**	2.4
Less:				
Cost of Sales – Natural Gas [1]	**(1.6)**	-	**(1.8)**	-
	$ 6.3	$ 2.8	**$ 6.1**	$ 2.4
Expenses				
Operating expenses	**(4.4)**	(1.1)	**(4.3)**	(1.1)
Other income	**-**	-	**-**	-
Division operating profit	**$ 1.9**	$ 1.7	**$ 1.8**	$ 1.3

[1] Represents Natural Gas revenue and gas costs since Aug 1, 2012 acquisition date

2012 Third Quarter Operating Results

For the three months ended September 30, 2012, Liberty Utilities (Central)'s revenue totalled U.S. $7.9 million as compared to U.S. $2.8 million during the same period in 2011, an increase of U.S. $5.1 million. The revenue increase can be mostly attributed to the addition of the natural gas distribution assets on August 1, 2012.

From the date of acquisition to September 30, 2012, Liberty Utilities (Central)'s revenue from natural gas sales and distribution totalled U.S. $5.5 million. August and September were the first two months of the operation of the natural gas distribution assets. The purchase of natural gas by Liberty Utilities (Central) 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 utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. From the date of acquisition to September 30, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled U.S. $3.9 million.

From the date of acquisition to September 30, 2012, natural gas purchases for Liberty Utilities (Central) totalled U.S $1.6 million.

Revenue from wastewater treatment totalled U.S. $1.4 million for the three months ended September 30, 2012 which was consistent with the same period in 2011.

Revenue from water distribution totalled U.S. $1.0 million for the three months ended September 30, 2012, as compared to U.S. $1.4 million during the same period in 2011, a decrease of U.S. $0.4 million.

For the three months ended September 30, 2012, operating expenses, excluding natural gas purchases, totalled U.S. $4.4 million, as compared to U.S. $1.1 million during the same period in 2011. The increase in operating expenses can be mostly attributed to the addition of the natural gas distribution assets on August 1, 2012.

For the three months ended September 30, 2012, Liberty Utilities (Central)'s operating profit was U.S. $1.9 million as compared to U.S. $1.7 million in the same period in 2011, an increase of U.S. $0.2 million or 12%.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, Liberty Utilities (Central)'s revenue from utility natural gas sales and distribution totalled $5.4 million. As the purchase of natural gas by Liberty Utilities (Central) is a significant revenue driver and component of operating expenses, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. Measured in Canadian dollars, from the date of acquisition to September 30, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (Central) totalled $3.6 million.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, natural gas purchases for Liberty Utilities (Central) totalled $1.8 million.

Measured in Canadian dollars, for the three months ended September 30, 2012, Liberty Utilities (Central)'s revenue from water treatment and wastewater distribution totalled $2.5 million, as compared to $2.4 million during the same period in 2011.

Measured in Canadian dollars, for the three months ended September 30, 2012, operating expenses, excluding natural gas purchases, totalled $4.3 million, as compared to $1.1 million during the same period in 2011.

Measured in Canadian dollars, for the three months ended September 30, 2012, Liberty Utilities (Central)'s operating profit totalled $1.8 million as compared to $1.3 million in the same period in 2011.

In the June 30, 2012 MD&A, guidance was provided on the Liberty Utilities (Central)'s expected operating results over the 12 month period ending June 30, 2013. From the date of acquisition to September 30, 2012, Midwest Gas Utilities' EBITDA of U.S. $0.7 million did not meet the guidance EBITDA of U.S. $1.3 million. The decreased EBITDA was due primarily to lower than expected natural gas usage in the states of Iowa and Missouri with Central recording actual usage of 398,800 MMBTU compared to the previous guidance of 488,042 MMBTU. Part of the decreased usage results from actual active natural gas connections being 80,395 compared to the previous guidance of 82,301 active natural gas connections a difference of 1,906 active connections.

The table below represents forward looking information that was provided as at August 9, 2012 and which summarizes the expected operating results for the Liberty Utilities (Central)'s gas utilities for the next three quarters:

Expected short term metrics	**2012 Q4**	**2013 Q1**	**2013 Q2**
Missouri	$2.8	$4.0	$1.3
Illinois	1.4	2.6	0.8
Iowa	0.4	0.9	0.2
Total EBITDA (U.S.$ millions)	$4.6	$7.5	$2.3
Customers	83,223	83,336	83,358
Normalized MMBTU	2,006,230	4,175,086	1,542,906

Readers are cautioned that actual results may vary from the above noted forward-looking information. Management is providing this forward looking information to allow readers to better understand the actual EBITDA of the acquired utilities as they occur in the year following acquisition, including the variation in financial performance that might be expected from quarter to quarter. Further, the forward-looking financial information does not include information for net earnings resulting from the acquisitions as it does not include information related to interest, depreciation, amortization and income taxes. Therefore, this forward-looking information may not be suitable or appropriate for other purposes other than as described herein. Management intends to report actual EBITDA results compared to this forward-looking information. Management does not intend to further update this financial information except as may be required by law.

Liberty Utilities (East)

	From the acquisition date to September 30[1] 2012	2011
Number of Active Natural Gas Connections		
Residential	74,100	-
Commercial and Industrial	10,650	-
Total Active Natural Gas Connections	**84,750**	**-**
Number of Active Electric Connections		
Residential	35,600	-
Commercial and Industrial	7,800	-
Total Active Electric Connections	**43,400**	**-**
Customer Usage (GW-hrs)		
Residential	79.3	-
Commercial and Industrial	183.1	-
Total Customer Usage (GW-hrs) [2]	**262.4**	**-**
Customer Usage (MMBTU)		
Residential	345,300	-
Commercial and Industrial	1,116,300	-
Total Customer Usage (MMBTU) [2]	**1,461,600**	**-**

[1] Granite State and EnergyNorth were acquired on July 3, 2012.

[2] Represents MMBTU and GW-hrs since July 3, 2012 acquisition date.

Liberty Utilities (East) is comprised of Liberty Utilities' operations in New Hampshire, Liberty Utilities (East) acquired its natural gas and electric distribution utilities on July 3, 2012 and, accordingly, there are no results for the utilities for the corresponding period in 2011.

Liberty Utilities (East) operates a regulated natural gas utility and an electric retail distribution company, both located in New Hampshire. Liberty Utilities (East) provides regulated natural gas services to approximately 84,750 active connections and regulated electric retail distribution service to approximately 43,400 active connections. Liberty Utilities (East) reports active connections, exclusive of vacant connections rather than total connections.

From the acquisition date of July 3, 2012 to September 30, 2012, Liberty Utilities (East)'s electricity usage totalled 262.4 GW-hrs and natural gas usage totalled 1,461,600 MMBTU.

		From the acquisition date to September 30[1]				From the acquisition date to September 30[1]		
		2012		2011		**2012**		2011
		U.S. $ (millions)		U.S. $ (millions)		**Can $ (millions)**		Can $ (millions)
Electricity Assets for regulatory purposes		**87.1**		-				
Natural Gas Assets for regulatory purposes		**257.6**		-				
Revenue								
Utility electricity sales and distribution	**$**	**19.1**	$	-	**$**	**19.1**	$	-
Utility natural gas sales and distribution		**12.2**		-		**12.2**		-
Other Revenue		**0.1**		-		**0.1**		-
		31.4		-		**31.4**		-
Less:								
Cost of Sales – Electricity		**(12.1)**		-		**(12.1)**		-
Cost of Sales – Natural Gas[2]		**(2.1)**		-		**(2.1)**		-
	$	**17.2**	$	-	**$**	**17.2**	$	-
Expenses								
Operating expenses		**(13.9)**		-		**(13.9)**		-
Division operating profit[1]	**$**	**3.3**	$	-	**$**	**3.3**	$	-

1 Granite State and EnergyNorth were acquired on July 3, 2012.

2 Natural Gas costs are shown net of US $2.8 million regulatory authorized deferral related to an under recovery of actual gas costs.

Liberty Utilities (East) has investments in natural gas assets for regulatory purposes of U.S. $257.6 million and electricity assets for regulatory purposes of U.S. $87.1 million as at September 30, 2012, as compared to U.S. $nil and U.S. $nil, respectively as at September 30, 2011.

From the date of acquisition to September 30, 2012, Liberty Utilities (East)'s revenue totalled U.S. $31.4 million as a result of the acquisitions of Granite State and EnergyNorth on July 3, 2012.

From the date of acquisition to September 30, 2012, Liberty Utilities (East)'s revenue from utility electricity sales totalled U.S. $19.1 million. The cost of electricity is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility electricity sales' (revenue from electricity sales less fuel and purchased power costs) as a more appropriate measure of the division's results. From the date of acquisition to September 30, 2012, net electricity utility sales for Liberty Utilities (East) totalled U.S. $7.0 million.

From the date of acquisition to September 30, 2012, Liberty Utilities (East)'s revenue from natural gas sales and distribution totalled U.S. $12.2 million. The cost of natural gas by Liberty Utilities (East) is passed through to Liberty Utilities (East)'s customers. As a result, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. From the date of acquisition to September 30, 2012, net utility natural gas sales and distribution revenue for Liberty Utilities (East) totalled U.S. $10.1 million.

From the date of acquisition to September 30, 2012, electricity purchases for Liberty Utilities (East) totalled U.S. $12.1 million, and natural gas purchases totalled U.S. $2.1 million.

From the date of acquisition to September 30, 2012, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $13.9 million.

From the date of acquisition to September 30, 2012, Liberty Utilities (East)'s operating profit totalled U.S. $3.3 million.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, Liberty Utilities (East)'s revenue from utility electricity sales totalled $19.1 million and net electricity utility sales totalled $12.2 million. As the purchase of natural gas by Liberty Utilities (East) is a significant revenue driver and component of operating expenses, the division compares 'net utility natural gas sales and distribution revenue' (utility natural gas sales and distribution revenue less natural gas purchases) as a more appropriate measure of the division's results. Measured in Canadian dollars, from the date of acquisition to September 30, 2012, Liberty Utilities (East)'s net utility electricity sales and distribution revenue totalled $7.0 million and net utility natural gas sales and distribution revenue totalled $10.1 million.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, Liberty Utilities (East)'s electricity purchases totalled $12.1 million, and natural gas purchases totalled $2.1 million.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, Liberty Utilities (East)'s operating expenses excluding electricity and natural gas purchases totalled $13.9 million.

Measured in Canadian dollars, from the date of acquisition to September 30, 2012, Liberty Utilities (East)'s operating profit totalled $3.3 million, as compared to $nil during the quarter ended September 30, 2011.

In the June 30, 2012 MD&A, guidance was provided on Granite State and EnergyNorth's expected operating results over the 12 month period ending June 30, 2013. From the date of acquisition to September 30, 2012, Granite State's EBITDA of U.S. $2.0 million exceeded the guidance EBITDA of U.S. $1.2 million. The increased EBITDA was due to greater than expected electricity usage by commercial and industrial connections. Actual electricity usage was 262.4 GW-hrs compared to the guidance of 244.7 GW-hrs. Actual active electric connections were 43,400 compared to the previous guidance of 43,205 active electric connections.

From the date of acquisition to September 30, 2012, EnergyNorth's EBITDA of U.S. $1.3 million exceeded the guidance EBITDA of U.S. $0.5 million. The increased EBITDA was due to greater than expected natural gas usage from commercial and industrial connections. Actual residential MMBTU was 1,461,600 compared to the previous guidance of 2,134,000. Actual active natural gas connections were 84,705 compared to the previous guidance of 86,403 active natural gas connections.

The table below represents forward looking information that was provided as at August 9, 2012 and which summarizes the expected operating results for Granite State and EnergyNorth over the next three quarters:

Expected short term metrics	2012 Q4	2013 Q1	2013 Q2
Granite State:			
Customers	43,259	43,312	43,365
Normalized MW-hrs	224,600	238,200	227,500
EBITDA (U.S.$ millions)	$0.8	$1.8	$1.0
EnergyNorth			
Customers	86,832	87,263	87,696
Normalized MMBTU	3,787,000	5,629,000	2,462,000
EBITDA (U.S. $ millions)	$5.0	$12.8	$3.9

Readers are cautioned that actual results may vary from the above noted forward-looking information. Management is providing this forward looking information to allow readers to better understand the actual EBITDA of the acquired utilities as they occur in the year following acquisition, including the variation in financial performance that might be expected from quarter to quarter. Further, the forward-looking financial information does not include information for net earnings resulting from the acquisitions as it does not include information related to interest, depreciation, amortization and income taxes. Therefore, this forward-looking information may not be suitable or appropriate for other purposes other than as described herein. Management intends to report actual EBITDA results compared to this forward-looking information. Management does not intend to further update this financial information except as may be required by law.

Outlook – Liberty Utilities

Liberty Utilities (West) expects continuing modest customer growth throughout its respective service territories in 2012.

On August 8, 2012, Liberty Utilities (Central) filed an incremental Infrastructure System Replacement Surcharge with the Missouri Public Service Commission (“MPSC”) to begin recovery related to system integrity investments made in October, 2010 through May, 2012. On October 31, 2012 the MPSC approved a $0.5 million increase in revenues. The Company began billing the increase on November 2, 2012.

On May 31, 2012, Liberty Utilities (West) filed a general rate case with the Arizona Corporation Commission related to the Rio Rico facilities seeking, among other things, an increase in EBITDA by U.S. $1.0 million over 2011 results if approved as filed. The application seeks recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application seeks a mechanism that helps mitigate the effects of regulatory lag on capital investment. The new rates are expected to be implemented in the second half of 2013.

On February 17, 2012, Liberty Utilities (West) filed a general rate case with the California Public Utilities

Commission ("CPUC") seeking, among other things, an increase of 10.0%, comprised of a U.S. $13.0 million revenue increase in distribution rates and a U.S. $3.3 million revenue increase to recover ongoing vegetation management costs, for a total revenue increase in distribution rates of U.S. $16.3 million. The application also seeks a reduction in flow through commodity costs of U.S. $8.8 million for the 2013 test year. Combined with forecasted changes in operating costs and ratemaking adjustments, the application sought to increase EBITDA by U.S. $7.7 million over 2011 results if approved as filed. On September 28, 2012, a Joint Motion to Accept All Party Settlement Agreement ("Settlement") was filed with the CPUC. The Settlement represents mutually accepted compromises among the Settling Parties regarding revenue requirement, cost of capital, revenue allocation, rate design, and other issues. The Settlement provides that the annual aggregate change in the Base Rate and Energy Cost Adjustment Clause revenue requirements shall be in total an increase of $3.747 million. Specifically, the Settlement adopts an overall increase in distribution rates of $12.475 million.

In addition to the revenue increase, a revenue decoupling mechanism was also agreed upon. The revenue decoupling mechanism will decouple base revenues from fluctuations caused by weather and economic factors. Liberty Utilities (West) expects that the new rates will be effective January 1, 2013.

In 2011, Liberty Utilities (West) applied to the CPUC for a vegetation memorandum account to allow for tracking vegetation management related costs. This account will allow Liberty Utilities (West) to seek rate recovery for vegetation management expenses incurred in 2012 until the effective date of the general rate case. The CPUC approved the vegetation memorandum account at its meeting of May 10, 2012.

APUC: Corporate and Other Expenses

	Three months ended September 30		**Nine months ended September 30**	
	2012	2011	**2012**	2011
Corporate and other expenses:	**(millions)**	(millions)	**(millions)**	(millions)
Administrative expenses	**$ 4.4**	$ 4.8	**$ 14.2**	$ 12.7
(Gain)/Loss on foreign exchange	**1.4**	(1.1)	**1.0**	(1.1)
Interest expense	**9.7**	7.4	**24.7**	22.9
Interest, dividend and other Income	**(0.4)**	(0.7)	**(1.7)**	(2.2)
Write down of long lived assets	**0.3**	-	**0.3**	-
Acquisition-related costs	**2.0**	0.8	**6.4**	1.8
(Gain)/Loss on derivative financial instruments	**(0.5)**	3.8	**0.2**	4.3
Income tax recovery	**(4.6)**	(16.5)	**(7.7)**	(16.4)

2012 Nine Months Corporate and Other Expenses

During the nine months ended September 30, 2012, administrative expenses totalled $14.2 million, as compared to $12.7 million in the same period in 2011. The expense increase in the nine months ended September 30, 2012 primarily results from additional personnel, increased wages, additional costs required to administer APUC's operations, share based compensation expense and other costs as compared to the same period in 2011.

For the nine months ended September 30, 2012, interest expense totalled $24.7 million as compared to $22.9 million in the same period in 2011. The increased interest expense is a result of higher long term rates associated with APCo's senior unsecured debentures and an interest accrual of $1.6 million in 2012 related to the Quebec water lease litigation as compared to the same period in 2011. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 1A Debentures in the prior year and the Series 2A Debentures in the first quarter.

For the nine months ended September 30, 2012, interest, dividend and other income totalled $1.7 million as compared to $2.2 million in the same period in 2011. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

For the nine months ended September 30, 2012, acquisition related costs totalled $6.4 million as compared to $1.8 million in the same period in 2011. The increase was primarily driven by the closing of Sandy Ridge on July 1, 2012, Granite State and EnergyNorth acquisitions on July 3, 2012 and the Midwest Gas Utilities on August 1, 2012.

An income tax recovery of $7.7 million was recorded in the nine months ended September 30, 2012, as compared to a recovery of $16.4 million during the same period in 2011. The income tax recovery for the nine months ended September 30, 2012 primarily resulted from the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, changes in the valuation allowance, and other non-taxable permanent differences. The income tax recovery of $16.4 million in the same period a year ago was primarily due to a realized foreign exchange loss for tax purposes as a result of a conversion of Canadian dollar denominated intercompany notes into U.S. dollar denominated preferred shares by a U.S. subsidiary of Algonquin Power Co. which resulted in reversal of a deferred tax asset valuation allowance that had been recorded in respect of the previously unrealized loss.

2012 Third Quarter Corporate and Other Expenses

During the quarter ended September 30, 2012, administrative expenses totalled $4.4 million, as compared to $4.8 million in the same period in 2011. The expense is lower than the previous year due to the timing of certain compensation related expenses that occurred in 2011 compared to 2012.

For the quarter ended September 30, 2012, interest expense totalled $9.7 million as compared to $7.4 million in the same period in 2011. Interest expense is consistent with the prior year as a result of higher long term rates associated with APCo's senior unsecured debentures compared to the short term rates that are associated with a short term bank credit facility as compared to the same period in 2011. These amounts were partially offset by reduced interest expense related to convertible debentures due to the conversion of the Series 2A Debentures in the first quarter.

For the quarter ended September 30, 2012, interest, dividend and other income totalled $0.4 million, as compared to $0.7 million in the same period in 2011. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

An income tax recovery of $4.6 million was recorded in the three months ended September 30, 2012, as compared to a recovery of $16.5 million during the same period in 2011. The income tax recovery for the three months ended September 30, 2012 primarily resulted from the recognition of deferred credits from the utilization of deferred income tax assets recognized at the time of the Unit Exchange Offer, non-taxable inter-corporate dividends, changes in the valuation allowance, and other non-taxable permanent differences. The income tax recovery of $16.5 million in the same period a year ago was primarily due to a realized foreign exchange loss for tax purposes as a result of a conversion of Canadian dollar denominated intercompany notes into U.S. dollar denominated preferred shares by a U.S. subsidiary of Algonquin Power Co.

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, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange. APUC adjusts for these factors as they may be non-cash, unusual in nature 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	
	2012	**2011**	**2012**	**2011**
	(millions)	(millions)	**(millions)**	(millions)
Net earnings/(loss) attributable to Shareholders	**$ (0.2)**	$ 19.6	**$ 8.1**	$ 31.9
Add (deduct):				
Net earnings attributable to the non controlling interest	**0.2**	0.8	**1.2**	3.5
Income tax (recovery)/expense	**(4.6)**	(16.5)	**(7.7)**	(16.4)
Interest expense	**9.7**	7.4	**24.7**	22.9
Acquisition costs	**2.0**	0.8	**6.4**	1.8
Write down of long-lived assets	**0.3**	-	**0.3**	-
Quebec water lease litigation	**-**	-	**0.5**	-
(Gain)/Loss on derivative financial instruments	**(0.5)**	3.8	**0.2**	4.3
(Gain)/Loss on foreign exchange	**1.4**	(1.1)	**1.0**	(1.1)
Depreciation and amortization	**15.9**	11.1	**37.7**	34.1
Adjusted EBITDA	**$ 24.2**	$ 25.9	**$ 72.4**	$ 81.0

For the nine months ended September 30, 2012, Adjusted EBITDA totalled $72.4 million as compared to $81.0 million, a decrease of $8.6 million or 11% as compared to the same period in 2011. For the quarter ended September 30, 2012, Adjusted EBITDA totalled $24.2 million as compared to $25.9 million, a decrease of $1.7 million or 7% as compared to the same period in 2011.

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	**Nine months ended September 30**
	(millions)	**(millions)**
Comparative Prior Period Adjusted EBITDA	$ 25.9	$ 81.0
Significant Changes:		
Liberty Utilities (West) - Reduced electricity sales due to warmer than expected weather	(1.9)	(5.4)
Liberty Utilities (West) - Revenue increases primarily due to rate case approvals	0.9	0.9
Liberty Utilities (Central) – Midwest Gas Utilities acquisition	0.7	0.7
Liberty Utilities (East) –EnergyNorth acquisition	1.4	1.4
Liberty Utilities (East) –Granite State acquisition	1.9	1.9
St Leon – Increased wind resource compared to prior year	(0.2)	0.9
St Leon II – Operations from facility expansion	0.4	0.4
Renewable – Decreased hydrologic resource	(2.5)	(5.3)
Windsor Locks – Reduced energy sales due to market conditions	(0.6)	(3.0)
Increased results from the stronger U.S. dollar	0.4	1.3
Tinker Hydro/AES - Decreased demand for retail sales and higher energy costs	(1.6)	(0.7)
Administrative expense	0.3	(1.6)
Other	(1.0)	(0.1)
Current Period Adjusted EBITDA	$ 24.2	$ 72.4

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 or litigation 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 and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funds actually being required for acquisitions. APUC uses adjusted net earnings to assess its performance without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment 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 its 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 unaudited interim 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		**Nine months ended September 30**	
	2012	**2011**	**2012**	**2011**
	(millions)	(millions)	**(millions)**	(millions)
Net earnings/(loss) attributable to Shareholders	**$ (0.2)**	$ 19.6	**$ 8.1**	$ 31.9
Add (deduct):				
(Gain)/Loss on derivative financial instruments, net of tax	**(0.3)**	2.5	**0.1**	3.0
Write down of long-lived assets, net of tax	**0.2**	-	**0.2**	-
Quebec water lease litigation, net of tax	**-**	-	**1.4**	-
Impact of HLBV loss, net of tax	**1.0**	-	**1.0**	-
(Gain)/Loss on foreign exchange, net of tax	**1.4**	(1.1)	**1.0**	(1.1)
Acquisition costs, net of tax	**1.2**	0.5	**3.9**	1.1
Adjusted net earnings	**$ 3.3**	$ 21.5	**$ 15.7**	$ 34.9
Adjusted net earnings per share	**$ 0.02**	$ 0.18	**$ 0.11**	$ 0.31

For the nine months ended September 30, 2012, adjusted net earnings totalled $15.7 million as compared to adjusted net earnings of $34.9 million, a decrease of $19.2 million as compared to the same period in 2011.

The decrease in adjusted net earnings for the nine months ended September 30, 2012 is primarily due to decreased earnings from operations, decreased income tax recovery amounts, higher depreciation and amortization expense, partially offset by higher income from interest and dividends as compared to the same period in 2011.

For the three months ended September 30, 2012, adjusted net earnings totalled $3.3 million as compared to adjusted net earnings of $21.5 million, a decrease of $18.2 million as compared to the same period in 2011 The decrease in adjusted net earnings for the three months ended September 30, 2012 is primarily due to decreased earnings from operations, decreased income tax recovery amounts, higher depreciation and amortization expense, partially offset by lower administration costs as compared to the same period in 2011.

Reconciliation of adjusted funds from operations to funds from operations

Adjusted funds from operations is a non-GAAP metric used by investors to compare funds from operations without the effects of certain volatile 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. Funds from operations (cash flows from operating activities) of APUC can be impacted positively or negatively by changes in working capital balances, acquisition and litigation expense. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funds actually being required for acquisitions. APUC uses adjusted funds from operations to assess its performance without the effects of changes in working capital balances, acquisition and litigation expense as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of funds from 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 and Statement of Cash Flows. This supplementary disclosure is intended to more fully explain disclosures related to adjusted funds from operations 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 funds from operations in accordance with GAAP.

The following table shows the reconciliation of funds from operations to adjusted funds from operations exclusive of these items:

	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
	(millions)	(millions)	**(millions)**	(millions)
Funds from operations	**$ 17.5**	$ 29.3	**$ 45.9**	$ 64.6
Add (deduct):				
Changes in non-cash operating items	**(4.7)**	(10.1)	**(3.3)**	(8.9)
Quebec water lease litigation accrual	**-**	-	**2.1**	-
Acquisition costs	**2.0**	0.8	**6.4**	1.8
Adjusted funds from operations	**$** 14.8	$ 20.0	**$ 51.1**	$ 57.5
Adjusted funds from operations per share	**$ 0.09**	$ 0.17	**$ 0.36**	$ 0.51

For the nine months ended September 30, 2012, adjusted funds from operations totalled $51.4 million as compared to adjusted funds from operations of $57.5 million, a decrease of $6.1 million as compared to the same period in 2011.

For the three months ended September 30, 2012, adjusted funds from operations totalled $15.1 million as compared to adjusted funds from operations of $20.0 million, an increase of $4.9 million as compared to the same period in 2011.

Summary of Property, Plant and Equipment Expenditures

	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
APCo	**(millions)**	**(millions)**	**(millions)**	**(millions)**
Renewable Energy Division				
Capital expenditures	**$ 4.0**	$ 16.9	**$ 13.6**	$ 18.9
Acquisition of operating entities	**28.8**	-	**28.8**	-
Total	**$ 32.8**	$ 16.9	**$ 42.4**	$ 18.9
Thermal Energy Division				
Capital expenditures, net	**$ (1.9)**	$ 9.0	**$ 12.3**	$ 9.1
Total	**$ (1.9)**	$ 9.0	**$ 12.3**	$ 9.1

	Three months ended September 30		Nine months ended September 30	
	2012	**2011**	**2012**	**2011**
LIBERTY UTILITIES	**(millions)**	**(millions)**	**(millions)**	**(millions)**
West				
Capital Investment in regulatory assets	**$ 7.0**	$ 3.6	**$ 13.6**	$ 11.1
Acquisition of operating entities	**-**	-	**-**	97.3
Total	**$ 7.0**	$ 3.6	**$ 13.6**	$ 108.4
Central				
Capital Investment in regulatory assets	**$ 1.6**	$ 0.1	**$ 2.0**	$ 0.6
Acquisition of operating entities	**129.6**	-	**129.6**	0.9
Total	**$ 131.2**	$ 0.1	**$ 131.6**	$ 1.5
East				
Capital Investment in regulatory assets	**$ 3.6**	$ -	**$ 3.6**	$ -
Acquisition of operating entities	**297.1**	-	**297.1**	-
Total	**$ 300.7**	$ -	**$ 300.7**	$ -
CONSOLIDATED				
Total APCo				
Capital expenditures	**$ 2.1**	$ 25.9	**$ 25.9**	$ 28.0
Acquisition of operating entities	**28.8**	-	**28.8**	-
Total Liberty Utilities				
Capital investment in regulatory assets	**12.2**	3.7	**19.2**	11.7
Acquisition of operating entities	**426.7**	-	**426.7**	98.2
Corporate	**-**	-	**0.1**	0.3
Total	**$ 469.8**	$ 29.6	**$ 500.7**	$ 138.2

APUC's consolidated capital expenditures in the nine months ended September 30, 2012 increased as compared to the same period in 2011 primarily due the acquisition of EnergyNorth, Granite State, the Midwest Gas Utilities, and Sandy Ridge all which closed in the third quarter.

Property, plant and equipment expenditures for the remainder of the 2012 fiscal year are anticipated to be between $16.0 million and $18.0 million. For Liberty Utilities, capital expenditures for the remainder of the year include approximately $7.1 million at Liberty Utilities (West) related to ongoing requirements for the expansion of the LPSCo and Woodmark water facilities and the California Utility, approximately $2.2 million relating to the Liberty Utilities (East) region's acquisition of Granite State and EnergyNorth and approximately $2.5 million relating to the Liberty Utilities (Central) region's acquisition of the Midwest Gas Utilities. For APCo, capital expenditures for the remainder of the year include approximately $4.3 million related to the APCo Renewable Energy Division, primarily related a major turbine upgrade at the Tinker facility.

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.

2012 Nine Month Property Plant and Equipment Expenditures

During the nine months ended September 30, 2012, APCo incurred capital expenditures of $25.9 million, as compared to $28.0 million during the comparable period in 2011 in addition to $28.8 million to acquire operating entities.

During the nine months ended September 30, 2012, APCo's Renewable Energy Division spent $13.6 million in capital expenditures as compared to $18.9 million in the comparable period in 2011. The capital expenditures primarily relate to the St. Leon II expansion, a major project at the Tinker Facility, and project costs related to the Cornwall Solar and Amherst Island development. Additionally, APCo's Renewable Energy Division spent $28.8 million on Sandy Ridge, the first of the three US Wind Farms being acquired. APCo's Thermal Energy Division net capital expenditures were $12.3 million, as compared to $9.1 million in the comparable period in 2011. The capital expenditures primarily relate to the Windsor Locks repowering and the major maintenance at the Sanger facility.

During the nine months ended September 30, 2012, Liberty Utilities invested $19.2 million in capital expenditures as compared to $11.7 million during the comparable period in 2011. Additionally, Liberty Utilities spent $426.7 million to acquire operating entities as compared to $98.2 million during the comparable period in 2011. Liberty Utilities (West)'s spend was primarily related to maintenance and refurbishment needs at the California Utility and the expansion of the LPSCo facility. Liberty Utility (Central)'s $2.0 million in capital expenditures was primarily a result of the $129.6 million acquisition of the Midwest Gas Utility. Liberty Utility (East)'s $3.6 million in capital expenditures was primarily a result of the $297.1 million acquisition of Granite State and EnergyNorth.

2012 Third Quarter Property Plant and Equipment Expenditures

During the quarter ended September 30, 2012, APCo incurred capital expenditures of $2.1 million, as compared to $25.9 million during the comparable period in 2011 in addition to $28.8 million to acquire operating entities.

During the quarter ended September 30, 2012, APCo Renewable Energy Division's capital expenditures were $4.0 million, as compared to $16.9 million in the comparable period in 2011. The capital expenditures primarily relate to the St. Leon II expansion, and a major project at the Tinker Facility. APCo Thermal Energy Division's net capital expenditures were ($1.9) million as compared to $9.0 million in the comparable period in 2011. The negative capital expenditure was primarily related to $4.6 million in capital expenditures related to the Windsor Locks repowering offset by a $6.5 million one-time non-recurring grant from the State of Connecticut.

During the quarter ended September 30, 2012, Liberty Utilities invested $12.2 million in capital expenditures as compared to $3.7 million during the comparable period in 2011. Additionally, Liberty Utilities spent $426.7 million to acquire operating entities. Liberty Utilities (West)'s spend was primarily related to maintenance and refurbishment needs at the California Utility and the expansion of the LPSCO facility. Liberty Utility (Central)'s $2.0 million in capital expenditures was primarily a result of the $129.6 million acquisition of the Midwest Gas Utility. Liberty Utility (East)'s $3.6 million in capital expenditures was primarily a result of the $297.1 million acquisition of Granite State and EnergyNorth.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo's Renewable Energy Division completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine remedial plans have been submitted to the Quebec government and two are undergoing options analysis by APCo. The nine remedial plans have been accepted by the Quebec government and one is still being reviewed.

APCo currently estimates further capital expenditures of approximately $16.4 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	**2012**	**2013**	**2014**	**2015**
Future Estimated Bill C-93 Capital Expenditures	**16,400**	300	5,500-	7,300	3,300

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

- APCo's proposed remediation plan for the Mont Laurier facility has been accepted by the Quebec government. APCo received the Certificate of Authorization from the Quebec government in November 2011. APCo completed the majority of the on-site remediation work in 2012 at a capital cost of approximately $0.3 million.
- APCo completed the dam safety evaluation for the Donnacona facility and is currently 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. APCo anticipates completing the engineering in 2012 and performing the remedial work in 2013 and 2014.
- The dam safety study and a detailed condition assessment for the St. Alban facility have been completed. APCO is reviewing the results of the condition assessment and expects to finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo anticipates completion of any required work on these dams by 2015.
- The dam remediation work related to Chute Ford was completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013.

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

APUC has revolving operating facilities available at both APCo and Liberty Utilities to manage the liquidity and working capital requirements of each division (collectively the "Facilities").

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, 2012 under the Facilities:

	As at September 30, 2012			As at June 30, 2012	As at Dec 31, 2011
	APCo (millions)	Liberty Utilities (millions)	Total (millions)	Total (millions)	Total (millions)
Committed Facilities	$ 155.0	$ 98.3	$ **253.3**	$ **195.7**	$ 120.0
Funds drawn on Facilities	(46.7)	(33.9)	(80.6)	(67.2)	-
Letters of Credit issued	$ (50.2)	$ (2.0)	$ (52.2)	$ (48.8)	$ (39.6)
Remaining available for draws on the Facilities	**$ 58.1**	**$ 62.4**	**$ 120.5**	**$ 79.7**	**$ 80.4**
Cash on Hand			16.4	160.9	72.9
Total liquidity and capital reserves	**$ 58.1**	**$ 62.4**	**$ 136.9**	**$ 240.6**	**$ 153.3**

On May 31, 2012, APCo concluded discussions with its banking syndicate to increase its senior credit facility from $120 million to $155 million to meet future working capital needs. As at September 30, 2012, the APCo Facility had drawn $46.7 million under the facility for working capital and capital expenditures. Additionally, APCo has $50.2 million in outstanding letters of credit.

On January 18, 2012, Liberty Utilities entered into an agreement for a senior unsecured revolving credit facility with a three year term. As at September 30, 2012, Liberty Utilities had drawn U.S. $34.5 million under the Liberty Facility for working capital and capital expenditure and U.S. $1.2 million for outstanding letters of credit. As a result of the close of the New Hampshire acquisitions on July 3, 2012, availability under the Liberty Facility has increased from U.S. $40 million to U.S. $100 million. The Liberty Facility has been sized appropriately for the liquidity requirements and working capital needs of the entire Liberty Utilities group following the acquisitions that are currently pending.

On July 2, 2012, Liberty Utilities closed the first of two tranches of a senior unsecured private debt placement of U.S. $225 million with an average life maturity of over 10 years and weighted average coupon of 4.38%. The first tranche closed on July 2, 2012 and raised U.S. $135 million in senior unsecured notes in connection with the New Hampshire acquisitions completed on July 3, 2012. The second tranche closed on July 31, 2012 and raised U.S. $90 million in senior unsecured notes in connection with the Midwest Gas Utilities acquisition completed on August 1, 2012. The total financing is spread over three maturity dates -

$50 million at 3.51% due in 2017, $115 million at 4.49% due in 2022 and $60 million at 4.89% due in 2027. The equity portion of these acquisitions was funded, in part, using subscription receipts convertible into APUC common shares and proceeds from a public equity issue completed in late 2011. See "*Shareholder's Equity and Convertible Debentures - Emera subscription receipts*" for a summary of these and other outstanding subscription receipts from Emera.

APCo expects to purchase a 58.75% majority interest in the US Wind Farms for a total purchase price of approximately U.S. $270 million, subject to certain other closing adjustments. APCo intends to finance the acquisition of the U.S. Wind Farms with approximately 45% debt and 55% equity. APCo expects to offer senior unsecured notes of approximately U.S. $120 million in connection with the U.S. Wind Farms acquisition. The equity portion of this acquisition is expected to be funded, in part, using subscription receipts convertible into APUC common shares. See "*Shareholder's Equity and Convertible Debentures - Emera subscription receipts*" for a summary of these and other outstanding subscription receipts from Emera. On July 1, 2012, APCo acquired a 51% controlling interest in the 50 MW Sandy Ridge wind project for approximately U.S. $29.7 million. Subsequent to the end of the quarter, APCo acquired an additional 7.75% interest for U.S. $4.5 million bringing the total interest to 58.75% for total consideration of U.S. $34.2 million. Funding was obtained through $15 million received from subscription receipts issued to Emera in connection with the acquisition and the remainder drawn on the APCo Facility.

Contractual Obligations

Information concerning contractual obligations as of September 30, 2012 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]	$	642.9	1.7	84.6	14.6	542.0
Convertible debentures	$	62.2	-	-	62.2	-
Advances in aid of construction	$	71.5	0.6	-	-	70.9
Interest on long-term debt obligations	$	293.6	38.7	70.2	65.0	119.7
Purchase obligations	$	80.8	80.8	-	-	-
Derivative financial instruments:						
Interest rate swap	$	5.3	2.0	3.3	-	-
Energy forward purchase contract	$	2.5	0.4	2.1	-	-
Capital lease obligations	$	0.4	0.2	0.2	-	-
Capital projects	$	0.6	0.1	0.5	-	-
Long term service agreements	$	92.0	4.3	8.3	8.6	70.8
Purchased power	$	149.7	43.0	85.0	21.7	-
Operating leases	$	1.6	0.7	0.8	0.1	-
Other obligations	$	15.3	4.1	-	-	11.2
Total obligations	$	1,418.4	$ 176.6	$ 255.0	$ 172.2	$ 814.6

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

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at September 30, 2012, APUC had 169,050,982 issued and outstanding common shares.

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.

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at September 30, 2012, APUC did not have any issued and outstanding preferred shares. Subsequent to the end of the quarter, APUC announced its intention to issue 4.8 million cumulative rate reset preferred shares, Series A (the "Series A Shares") yielding 4.5% per cent annually for the initial six-year period ending on December 31, 2018. The Series A Shares were issued at a price of $25.00 per share, for aggregate gross proceeds of $120 million. The offering was completed on November 9, 2012.

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered holders of shares ("Shareholders") of APUC.

As at September 30, 2012, 26.8 million common shares representing approximately 16% of total shares outstanding had been registered with the Reinvestment Plan and during the quarter 311,885 common shares were issued under the Reinvestment Plan. Subsequent to the end of the quarter, on October 15, 2012, an additional 325,341 common shares were issued under the Reinvestment Plan.

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

During the nine months ended September 30, 2012, a principal amount of $360 Series 3 Debentures were converted into 85,704 shares of APUC. On September 30, 2012, there were 62,211 Series 3 Debentures outstanding with a face value of $62, 211.

EMERA SUBSCRIPTION RECEIPTS

On May 14, 2012, in connection with the acquisition of Granite State and EnergyNorth, APUC issued 12.0 million shares at a price of $5.00 per share to Emera pursuant to a subscription receipt agreement. The $60.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions.

During the nine month period September 30, 2012, APUC issued 10.46 million subscription receipts at a price of $5.74 per share and 6.98 million subscription receipts at a price of $6.45 per share to Emera pursuant to subscription receipt agreements in connection with certain transactions for a total of 17.43 million subscription receipts valued at $105.0 million.

On June 29, 2012, in connection with the acquisition of Sandy Ridge, APUC received $15.0 million relating to 2,614,006 subscription receipts representing a price of $5.74 per share and issued shares relating to these subscription receipts subsequent to the end of the quarter.

On August 1, 2012, in connection with the acquisition of the Midwest Gas Utilities, APUC issued 6.98 million shares at a price of $6.45 per share to Emera pursuant to a subscription receipt agreement. The $45.0 million cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

Following the above noted subscription receipts transactions, the subscriptions receipts that remain outstanding are as follows: 7.8 million subscription receipts at a price of $5.74 per share in connection with the acquisition of the remaining U.S. wind farm projects and 8.2 million subscription receipts at a price of $4.72 per share in connection with the Company's acquisition of Emera's minority interest in Liberty Energy (California).

As at November 14, 2012, in total Emera now owns 30.1 million APUC common shares representing approximately 17.8% of the total outstanding common shares of the Company. APUC believes issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

SHARE BASED COMPENSATION PLANS

For the three and nine months ended September 30, 2012, APUC recorded $417 and $1,263 (2011 - $228 and $445) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at September 30, 2012, total unrecognized compensation costs related to non-vested options and share unit awards were $2,098 and $32 respectively, and are expected to be recognized over a period of 1.78 years and 1.25 years respectively.

STOCK OPTION PLAN

APUC has a stock option plan that permits the grant of share options to key officers, directors, employees and selected service providers. Options may be exercised up to eight years following the date of grant.

During the three months ended September 30, 2012, no options were granted to senior executives or certain senior management of APUC.

During the three months ended September 30, 2012, no options were exercised. As at September 30, 2012, APUC had 3,750,727 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 a 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.

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. The PSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle these instruments in cash, these PSUs are accounted for as equity awards.

DIRECTORS DEFERRED SHARE UNITS

APUC has 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. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards.

As at September 30, 2012, 44,047 DSUs had been granted.

EMPLOYEE SHARE PURCHASE PLAN

APUC has an employee share purchase plan (the "ESPP") which allows eligible employees to use a portion of their earnings to purchase common shares of APUC. 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, 2012, a total of 47,802 shares had been issued under the ESPP.

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.

Transactions with APMI and Senior Executives

- 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 and nine months ended September 30, 2012 were $82 and $245 (2011 - $82 and $245).
- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. During the three and nine months ended September 30, 2012, APUC incurred costs in connection with the use of the aircraft of $331 and $495 (2011 - $226 and $350) and amortization expense related to the advance against expense reimbursements of $73 and $228 (2011 - $77 and $205). At September 30, 2012, the remaining amount of the advance was $52 (December 31, 2011 - $279) 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"), a subsidiary of APUC and the legal owner of the St. Leon facility. The related holders of the Class B units received cash distributions of $59 and $214 for the three and nine months ended September 30, 2012 (2011 - $121 and $208).

- 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. In 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 owing to APMI is included in accrued liabilities at September 30, 2012.
- Staff managed by APUC has historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest.
- As at September 30, 2012, included in amounts due from related parties is $819 (December 31, 2011 - $663) owed to APUC from APMI and included in amounts due to related parties is $1,805 (December 31, 2011 - $1,795) owed to APMI. These amounts arise from the transactions described above.
- 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.

Transactions with Emera

- A subsidiary of Emera provides 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, 2012 APUC paid U.S. $nil (2011 – U.S. $nil and $102) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.
- For the three and nine months ended September 30, 2012, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,566 and $4,556 (2011 – U.S. $1,659 and $5,301). In 2011, 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, 2012, included in amounts due from related parties is $1,571 (December 31, 2011 - $1,612) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.
- The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Business Associations with APMI and Senior Executives

There have been a number of business relationships between Ian Robertson and Chris Jarratt ("Senior Executives"), APMI and related affiliates (collectively the "Parties") and APUC. These relationships include joint ownership of certain generating facility assets, business relationships between the parties and payment of fees associated with previous transactions. In 2011, the Board conducted a process to review all of the remaining business associations with the Parties in order to reduce, streamline and simplify these relationships. The Board formed a special committee and engaged independent consultants to assist with this process.

The co-owned assets and remaining business associations as at September 30, 2012 are listed below. During the quarter ended March 31, 2012, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "Agreement"). The transaction is subject to finalization of definitive agreements which are expected to be completed in the fourth quarter of 2012. A more detailed description of the Agreement has been set out below in *Settlement of Other Business Associations*.

i) Rattlebrook hydroelectric generating facility

Rattlebrook is a 4 MW hydroelectric generating station owned 45% by APUC, 27.5% by Senior Executives and the remaining percentage by third parties. This relationship was addressed pursuant to the Agreement. See *Settlement of Other Business Associations* below for more details.

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. APUC and the Class B unit holders have simplified the relationship by amalgamating the previous partnership agreement and two amending agreements into an amended and restated agreement. In addition, APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allowed APUC to recently expand the St Leon project by 16.5 MW on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

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 which has been accrued. This relationship and corresponding liability was addressed pursuant to the Agreement.

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. This relationship was addressed pursuant to the Agreement.

v) Chartered aircraft

APUC utilizes chartered aircraft owned by an affiliate of APMI. At September 30, 2012, $52 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 2013 when the advance will be fully utilized pursuant to the Agreement.

vi) *Office lease*

APUC has leased its head office facilities on a triple net basis from an entity partially owned by Senior Executives. The lease expires on December 31, 2015.

vii) *Operations services*

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. APUC is providing supervisory management on a cost recovery basis for one of the facilities until December 31, 2012.

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. An amount of U.S. $0.6 million has been accrued as an estimate of the final fee owed to APMI. This liability was settled pursuant to the Agreement.

ix) *Clean Power Income Fund*

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund ("Clean Power") 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 December 31, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet. This liability was settled pursuant to the Agreement.

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. These liabilities were settled pursuant to the Agreement.

xi) *Trafalgar*

APCo owns debt on seven hydroelectric facilities owned by Trafalgar Power Inc. and an affiliate ("Trafalgar"). In 1997, an affiliate of APMI 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 Appeal dismissed all the claims against APCo in the civil proceedings and remanded one issue to the District Court. On April 3, 2012, the District Court granted APUC summary judgment on its counter-claims against Trafalgar. The District Court found that Trafalgar was in default of the indenture and the loan agreements and that APUC was entitled to proceed to enforce its rights against its collateral. Trafalgar has filed a notice of appeal of the Memorandum-Decision & Order. Algonquin filed its brief on October 19, 2012 with a hearing dated anticipated in the first quarter of 2013. The bankruptcy proceedings are continuing with a Second Circuit Court of Appeal hearing scheduled for December 12, 2012 to hear the appeal of the District Court's October 25, 2011 decision holding that Algonquin does not have a security interest in the monies transferred by Trafalgar before it filed for bankruptcy protection.

Settlement of Other Business Associations

During the quarter ended March 31, 2012, APUC and APMI's Senior Executives (the "Parties") reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the fourth quarter of 2012.

Under this term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including the Sanger repowering project, the offer to acquire Clean Power Income Fund and the development of the Red Lily I wind project.

The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the Rattlebrook and Long Sault Rapids facilities, provide a valuation of these assets and to provide advice to APUC in respect thereof.

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. See APUC's audited consolidated financial statements for the years ended December 31, 2011 and 2010 or the most recent AIF for discussion of these risks.

Market price risk

On May 15, 2012, APCo entered into a financial hedge with respect to its Dickson Dam hydroelectric facility located in the Western region. The financial hedge is structured to hedge 75% of APCo's production volume against exposure to the Alberta Power Pool's current spot market rates. For the unhedged portion of production, each $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of $0.2 million on an annualized basis.

The July 1, 2012 acquisition of Sandy Ridge included a financial hedge which commences on January 1, 2013 for a 10 year period. Until the effective date, Sandy Ridge is exposed to current spot market rates in the PJM West market. For the third and fourth quarters of 2012, each $10 per MW-hr change in the market prices would result in a change in revenue of about $0.7 million.

Interest rate risk

APCo's operating credit facility is subject to a variable interest rate. The APCo Facility had $46.7 million outstanding as at September 30, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.5 million annually.

Liberty Utilities' operating credit facility is subject to a variable interest rate. The Liberty Facility had $33.9 million outstanding as at September 30, 2012. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually.

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 and its subsidiaries will always have sufficient independent liquidity to meet their liabilities when due.

As at September 30, 2012, APUC had $120.5 million of committed and available Facilities remaining and $16.4 million of cash resulting in $136.9 million of total liquidity and capital reserves.

The long term portion of the Facilities and project specific debt total approximately $640 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment 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.

APUC currently pays a dividend of $0.31 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.

Commodity price risk

APCo, Liberty Utilities (Central) and Liberty Utilities (East)'s exposure to commodity prices is primarily limited to exposure to natural gas and energy price risk. Liberty Utilities (Central) and Liberty Utilities (East) employs energy hedges in an effort to minimize their respective exposures to commodity price risk. Liberty Utilities (West) is exposed to energy price risk which is mitigated through certain regulatory constructs. See APUC's audited consolidated financial statements for the years ended December 31, 2011 and 2010 for discussion of this risk.

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. A detailed assessment of APUC's business risks is set out in the most recent AIF.

Risks Associated with owning a Gas Utility

As a result of the acquisition of EnergyNorth and the Midwest Gas Utilities, the Company is exposed to risks inherent in natural gas transmission and distribution activities, such as leaks, explosions and mechanical problems which could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For assets located near populated areas, the level of damage resulting from these risks could be greater.

Litigation risks and other contingencies

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

APCo owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. 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. For additional comments on this matter, see *"Business Associations with APMI and Senior Executives - Trafalgar"*.

On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5.4

million (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $5.8 million. The parties are attempting to resolve this matter through good faith negotiations.

Disclosure Controls

As of September 30, 2012, under the supervision and with the participation of APUC's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), management carried out an evaluation, 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 September 30, 2012, 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. 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.

During the quarter ended September 30, 2012, APUC acquired EnergyNorth, Granite State, the Midwest Gas Utilities, and Sandy Ridge. The financial information for these business acquisitions is included in this MD&A and in Note 3 of the unaudited interim financial statements. National Instrument 52-109 and the US Securities and Exchange Commission provide an exemption, whereby companies undergoing acquisitions, can exclude the acquired business in the year from the scope of testing and assessment of operational effectiveness of controls over financial reporting. Due to the complexity associated with assessing internal controls during integration efforts, the Company plans to utilize the scope exemption as it relates to these acquisitions in management's report on internal controls over financial reporting for the year ended December 31, 2012.

Changes in internal controls over financial reporting

APUC is in the process of implementing its internal control structure over the operations of the acquired businesses discussed above. However, 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.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the eight quarters ended September 30, 2012:

Millions of dollars (except per share amounts)	4th Quarter 2011	1st Quarter 2012	2nd Quarter 2012	3rd Quarter 2012
Revenue	$ 72.1	$ 64.4	$ 65.4	$ 99.0
Adjusted EBITDA	24.3	22.8	24.9	24.2
Net earnings / (loss) attributable to shareholders	(8.5)	2.3	6.1	(0.2)
Net earnings / (loss) per share	(0.07)	0.02	0.04	0.00
Adjusted net earnings	10.0	4.1	6.9	2.4
Adjust net earnings per share	0.08	0.03	0.05	0.01
Total Assets	1,282.6	1,265.6	1,416.0	1,967.1
Long term debt*	455.0	403.7	473.8	705.1
Dividend declared per share	0.07	0.07	0.07	0.0775

	4th Quarter 2010	1st Quarter 2011	2nd Quarter 2011	3rd Quarter 2011
Revenue	$ 48.4	$ 71.7	$ 66.8	$ 66.0
Adjusted EBITDA	20.8	26.9	28.2	25.8
Net earnings attributable to shareholders	15.6	5.0	7.3	19.6
Net earnings per share	0.17	0.05	0.07	0.17
Adjusted net earnings	18.2	5.3	8.2	22.4
Adjust net earnings per share	0.19	0.05	0.07	0.19
Total Assets	1,016.9	1,175.8	1,177.7	1,263.1
Long term debt*	441.7	507.0	451.1	472.2
Dividend declared per share	0.06	0.065	0.065	0.07

* Long term debt includes current and long term portion of debt and convertible debentures

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 $48.4 million and $99.0 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 fluctuation in the strength of the Canadian dollar which can result in significant changes in reported revenue from U.S. operations.

Quarterly net earnings attributable to shareholders have fluctuated between net earnings attributable to shareholders of $19.6 million and a net loss of $8.5 million over the prior two year period. Earnings have been significantly impacted by non-cash factors such as deferred tax recovery and expense, impairment of intangibles, property, plant and equipment and mark-to-market gains and losses on financial instruments.

Critical Accounting Estimates and Polices

APUC prepared its unaudited interim 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. Significant accounting policies requiring the use of management estimates relate to the useful lives and recoverability of depreciable assets, recoverability of deferred tax assets, rate-regulation, unbilled revenue, fair value of derivatives, pension and post-retirement benefits and environmental remediation obligation. Management believes there has been no material changes during the three months ended September 30, 2012 to the items discussed in APUC's MD&A and Note 1 of its consolidated financial statements for the year ended December 31, 2011 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Actual results may differ from these estimates.

Interim Consolidated Balance Sheets
(Unaudited)
(thousands of Canadian dollars)

	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	**$ 16,395**	$ 72,887
Short term investments	**833**	833
Accounts receivable net of allowance for doubtful accounts of $4,174 and $385 (note 4)	**63,067**	44,113
Due from related parties (note 12)	**2,390**	2,275
Prepaid expenses	**5,649**	5,620
Supplies and consumables inventory	**22,923**	2,714
Notes receivable (note 5)	**523**	482
Deferred tax asset	**15,807**	13,022
Income tax receivable	**556**	133
Derivative instruments	**1,701**	-
Regulatory assets (note 6)	**7,269**	2,458
	137,113	144,537
Long-term investments and notes receivable (note 5)	**37,744**	39,820
Deferred non-current income tax asset	**76,701**	67,671
Property, plant and equipment	**1,489,261**	945,956
Intangible assets	**57,491**	55,269
Goodwill	**36,242**	9,710
Restricted cash	**7,056**	4,693
Deferred financing costs	**8,099**	8,503
Derivative instruments (note 17)	**3,038**	-
Non-current regulatory assets (note 6)	**102,371**	2,571
Other assets	**12,012**	3,577
	$ 1,967,128	$ 1,282,307

Interim Consolidated Balance Sheets (continued)

(Unaudited)

(thousands of Canadian dollars)

	September 30, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	**$ 20,232**	$ 8,382
Accrued liabilities	**58,278**	46,821
Due to related parties (note 12)	**1,805**	1,795
Dividends payable	**13,280**	9,566
Regulatory liabilities (note 6)	**2,727**	2,469
Long-term liabilities (note 7)	**1,727**	1,624
Other long-term liabilities	**4,296**	1,037
Advances in aid of construction	**584**	604
Derivative instruments (note 17)	**2,974**	2,935
Income tax liability	**294**	407
Deferred credits	**7,266**	6,314
Deferred income tax liability	**605**	723
	114,068	82,677
Long-term liabilities (note 7)	**641,171**	331,092
Convertible debentures (note 8)	**62,211**	122,297
Other long-term liabilities	**14,797**	11,027
Advances in aid of construction	**70,929**	74,547
Non-current regulatory liabilities (note 6)	**74,194**	19,184
Deferred non-current income tax liability	**119,312**	53,231
Derivative instruments (note 17)	**5,389**	5,209
Deferred credits	**27,305**	30,348
Pension and post retirement benefits	**28,933**	-
Environmental obligation	**52,855**	-
Equity:		
Shareholders' capital (note 9)	**1,159,442**	975,263
Additional paid-in capital (note 9)	**2,788**	1,525
Deficit	**(392,637)**	(366,080)
Accumulated other comprehensive loss	**(106,806)**	(96,510)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	**662,787**	514,198
Non-controlling interests	**93,177**	38,497
Total Equity	**755,964**	552,695
Commitments and contingencies (note 13)		
Subsequent events (notes 3 and 9)	**$ 1,967,128**	$ 1,282,307

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 September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Revenue:				
Regulated electricity sales and distribution	**$ 36,309**	$ 16,663	**$ 71,608**	$ 56,082
Regulated gas sales and distributions	**17,586**	-	**17,586**	-
Regulated water reclamation and distribution	**12,479**	12,257	**35,133**	33,523
Non-regulated energy sales	**27,580**	31,952	**90,519**	99,833
Waste disposal fees	**3,998**	4,074	**11,604**	12,360
Other revenue	**1,089**	1,102	**2,412**	2,785
	99,041	66,048	**228,862**	204,583
Expenses				
Operating	**41,217**	20,967	**88,627**	65,163
Regulated electricity purchased	**23,088**	9,949	**44,532**	33,015
Regulated gas purchased	**3,904**	-	**3,904**	-
Non-regulated fuel for generation	**3,133**	5,966	**10,174**	16,832
Depreciation of property, plant and equipment	**14,894**	9,547	**34,561**	29,205
Amortization of intangible assets	**1,043**	1,527	**3,120**	4,890
Administrative expenses	**4,375**	4,755	**14,239**	12,686
Write down of long-lived assets	**260**	-	**260**	-
Loss/(gain) on foreign exchange	**1,449**	(1,149)	**1,040**	(1,051)
	93,363	51,562	**200,457**	160,740
Operating income	**5,678**	14,486	**28,405**	43,843
Interest expense	**9,706**	7,429	**24,685**	22,870
Interest, dividend income and other income	**(891)**	(1,407)	**(4,501)**	(4,060)
Acquisition-related costs	**1,976**	772	**6,407**	1,786
Loss/(gain) on derivative financial instruments (note 17(b))	**(456)**	3,754	**175**	4,285
	10,335	10,548	**26,766**	24,881
Earnings/(loss) from operations before income taxes	**(4,657)**	3,938	**1,639**	18,962
Income tax expense (recovery) (note 11)				
Current	**338**	223	**484**	868
Deferred	**(4,951)**	(16,688)	**(8,136)**	(17,302)
	(4,613)	(16,465)	**(7,652)**	(16,434)
Net earnings/(loss)	**(44)**	20,403	**9,291**	35,396
Net earnings attributable to non-controlling interests	**192**	819	**1,185**	3,466
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	**$ (236)**	$ 19,584	**$ 8,106**	$ 31,930
Basic net earnings per share (note 14)	**$ 0.00**	$ 0.16	**$ 0.05**	$ 0.29
Diluted net earnings per share (note 14)	**$ 0.00**	$ 0.16	**$ 0.05**	$ 0.28

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statements of Comprehensive Income (Loss)
(Unaudited)
(thousands of Canadian dollars)

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Net earnings/(loss)	**$ (44)**	$ 20,403	**$ 9,291**	$ 35,396
Other comprehensive income (loss), before tax:				
Foreign currency translation adjustment	**(15,069)**	23,289	**(15,020)**	14,911
Unrealized gain on cash flow hedge	**1,891**	-	**2,087**	-
Increase in pension obligation	**4**	-	**-**	-
Other comprehensive income (loss), before tax	**(13,174)**	23,289	**(12,933)**	14,911
Income tax expense related to items of other comprehensive income	**610**	-	**662**	-
Other comprehensive income (loss), net of tax	**(13,784)**	23,289	**(13,595)**	14,911
Comprehensive income	**(13,828)**	43,692	**(4,304)**	50,307
Comprehensive income attributable to the non-controlling interest	**(3,156)**	4,605	**(2,114)**	5,549
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	**$ (10,672)**	$ 39,087	**$ (2,190)**	$ 44,758

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statement of Equity

(Unaudited)

(thousands of Canadian dollars)

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2011	$ 975,263	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$ 552,695
Dividends declared and distributions to non-controlling interests	-	-	(29,396)	-	(357)	(29,753)
Dividends and issuance of shares under dividend reinvestment plan	5,267	-	(5,267)	-	-	-
Conversion and redemption of convertible debentures	58,610	-	-	-	-	58,610
Issuance of common shares	120,000	-	-	-	-	120,000
Issuance of common shares under employee share purchase plan	302	-	-	-	-	302
Share-based compensation	-	1,263	-	-	-	1,263
Acquisition of Sandy Ridge	-	-	-	-	57,151	57,151
Net earnings			8,106		1,185	9,291
Other comprehensive loss	-	-	-	(10,296)	(3,299)	(13,595)
Balance, September 30, 2012	$ 1,159,442	$ 2,788	$ (392,637)	$ (106,806)	$ 93,177	$ 755,964

See accompanying notes to interim consolidated financial statements

Interim Consolidated Statements of Cash Flows

(Unaudited)

(thousands of Canadian dollars)

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Cash provided by (used in):				
Operating Activities:				
Net earnings/(loss)	**$ (44)**	$ 20,403	**$ 9,291**	$ 35,396
Adjustments and items not affecting cash:				
Depreciation of property, plant and equipment	**14,894**	9,547	**34,561**	29,205
Amortization of intangible assets	**1,043**	1,527	**3,120**	4,890
Other amortization	**1,873**	558	**2,994**	1,636
Deferred taxes	**(4,951)**	(16,688)	**(8,136)**	(17,302)
Unrealized (gain)/loss on derivative financial instruments	**(1,220)**	3,074	**(2,050)**	1,518
Share-based compensation	**417**	228	**1,263**	445
Increase in pension and post retirement benefits	**1,213**	-	**1,213**	-
Write down of long lived assets	**260**	-	**260**	-
Unrealized foreign exchange (gain)/loss	**(721)**	612	**57**	(81)
Changes in non-cash operating items (note 15)	**4,714**	10,054	**3,296**	8,936
	17,478	29,315	**45,869**	64,643
Financing Activities:				
Cash dividends	**(9,198)**	(7,748)	**(25,681)**	(20,236)
Cash distributions to non-controlling interest	**(99)**	(105)	**(357)**	(346)
Issuance of common shares	**45,135**	-	**120,302**	27,700
Deferred financing costs	**(658)**	(1,453)	**(2,486)**	(2,876)
Increase in long-term liabilities	**243,163**	127,897	**309,192**	203,019
Decrease in long-term liabilities	**(324)**	(120,891)	**(980)**	(122,615)
Increase/(decrease) in advances in aid of construction	**(100)**	2,564	**1,003**	4,866
Increase/(decrease) in other long-term liabilities	**(560)**	(159)	**(455)**	123
	277,359	105	**400,538**	89,635
Investing Activities:				
Decrease in restricted cash	**57**	343	**737**	158
Decrease/(increase) in short-term investments	**-**	5,859	**-**	(4,744)
Increase in other assets	**(1,214)**	(280)	**(4,759)**	(698)
Distributions received in excess of equity income	**480**	(190)	**312**	2,940
Receipt of principal on notes receivable	**1,534**	110	**1,769**	1,059
Decrease/(increase) in non-controlling interest	**-**	(22)	**-**	1,328
Proceeds from liquidation of Highground assets	**-**	734	**-**	1,073
Increase in long-term investments and notes receivable	**-**	-	**-**	(6,900)
Proceeds from sale of subsidiaries	**-**	-	**204**	-
Additions to property, plant and equipment	**(13,106)**	(29,476)	**(42,774)**	(39,911)
Additions to intangibles	**(1,177)**	-	**(2,237)**	-
Acquisitions of operating entities (note 3(a),(b) and (d))	**(425,137)**	(132)	**(455,424)**	(98,226)
	(438,563)	(23,054)	**(502,172)**	(143,921)
Effect of exchange rate differences on cash	**(735)**	507	**(727)**	419
Increase/(decrease) in cash and cash equivalents	**(144,461)**	6,873	**(56,492)**	10,776
Cash and cash equivalents, beginning of the period	**160,856**	8,652	**72,887**	4,749
Cash and cash equivalents, end of the period	**$ 16,395**	$ 15,525	**$ 16,395**	$ 15,525
Supplemental disclosure of cash flow information:				
Cash paid during the period for interest expense	**$ 8,696**	$ 2,070	**$ 20,300**	$ 19,116
Cash paid during the period for income taxes	**$ -**	$ 145	**$ 251**	$ 192
Non-cash transactions				
Property, plant and equipment acquisitions in accruals	**$ 6,204**	$ 6,699	**$ 6,204**	$ 6,699

See accompanying notes to interim consolidated financial statements

Notes to the Unaudited Interim Consolidated Financial Statements

Three and nine months ended September 30, 2012 and 2011
(in thousands of Canadian dollars except as noted and amounts per share)

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, gas and electric utilities, through investments in securities of subsidiaries including corporations, limited partnerships and trusts which carry on these businesses.

APUC's power generation business unit conducts business under the name Algonquin Power Co. ("APCo"). 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"). Liberty Utilities operates a portfolio of utilities in the United States of America providing electric, natural gas, water distribution or wastewater services. The regulated utility operating companies owned by Liberty Utilities are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (see note 6).

1. Significant accounting policies

(a) Basis of preparation:

The accompanying 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 under Regulation S-X Rule 10-10, Interim Financial Statements provided by the Securities and Exchange Commission ("SEC").

The significant accounting policies applied to these unaudited interim consolidated financial statements of APUC are consistent with those disclosed in the audited consolidated financial statements of APUC for the year ended December 31, 2011 except for accounting policies adopted for fair value measurement (note 2(a)), Hypothetical Liquidation at Book Value ("HLBV") method (note 3(d)), and hedge of the foreign currency exposure of its net investment in foreign operations (note 7).

APUC's operating results are subject to seasonal fluctuations that could 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. APUC's water and wastewater utility assets revenues fluctuate depending on the 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 the California Utility experiences higher demand for electricity than during the summer period since the utility serves a number of ski hills and resorts in its service territory.

(b) Basis of consolidation:

The accompanying consolidated financial statements of APUC include the accounts of APUC and its wholly owned subsidiaries and variable interest entities ("VIEs") where the Company is the primary beneficiary. Intercompany transactions and balances have been eliminated.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

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 not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The adoption of this guidance in 2012 did not have a material impact on the Company's consolidated financial statements.

2. Recently issued accounting pronouncements (continued)

(b) Recent accounting guidance not yet adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This newly issued accounting standard requires an entity to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions executed under a master netting or similar arrangement and was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this accounting standard only requires enhanced disclosure, the adoption of this standard is not expected to have an impact the Company's financial position or results of operations.

3. Business acquisitions and developments projects

(a) Acquisition of New Hampshire electric and gas utilities

On July 3, 2012, Liberty Utilities acquired 100% of the common shares of Granite State Electric Company ("Granite State"), a regulated electric utility, and EnergyNorth Natural Gas Inc. ("EnergyNorth") a regulated natural gas utility for total cash consideration of $301,153 (U.S. $297,436) subject to final closing adjustments.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed at the acquisition date:

	Granite State	EnergyNorth	Total
Cash	$ 230	-	$ 230
Restricted cash	3,314	-	3,314
Working capital	482	26,916	27,398
Property, plant and equipment	86,902	256,291	343,193
Regulatory assets	22,209	77,283	99,492
Deferred financing	31	-	31
Other assets	172	7,866	8,038
Goodwill	-	16,635	16,635
Current portion other long-term liabilities	(661)	(962)	(1,623)
Long-term debt	(15,187)	-	(15,187)
Other long-term liabilities	(1,534)	(2,495)	(4,029)
Advances in aid of construction	(3)	(86)	(89)
Derivative liabilities	-	(2,598)	(2,598)
Regulatory liabilities	(5,494)	(27,567)	(33,061)
Pension and post-retirement benefits	(7,346)	(18,146)	(25,492)
Environmental obligation	-	(54,432)	(54,432)
Deferred income tax liabilities, net	-	(60,667)	(60,667)
	$ 83,115	$ 218,038	$ 301,153
Less: Cash acquired	(230)	-	(230)
Total net assets acquired	$ 82,885	$ 218,038	$ 300,923

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 the fair value measurements. 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 fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts noted.

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill include expected future cash flows, potential operational synergies,

3. Business acquisitions and developments projects (continued)

(a) Acquisition of New Hampshire electric and gas utilities (continued)

the utilization of technology, and cost savings opportunities in the delivery of certain shared administrative and other services. The goodwill related to EnergyNorth and Granite State will be allocated to the Liberty Utilities (East) segment.

Property, plant & equipment are amortized in accordance with regulatory requirements which are generally over the estimated useful lives of the assets using the straight line method. The weighted average life of the acquired assets of EnergyNorth and Granite State are 40 years and 28 years respectively.

All costs related to the acquisition have been expensed in the consolidated Statement of Operations.

Granite State and EnergyNorth contributed revenue of $31,371 and a loss of $999 to the Company's results for the three months ended September 30, 2012.

(b) Acquisition of Midwest Gas Utilities

On August 1, 2012, Liberty Utilities acquired certain regulated natural gas distribution utility assets (the "Midwest Gas Utilities") located in Missouri, Iowa, and Illinois. The total purchase price for the Midwest Utilities was approximately $128,890 (U.S. $128,223), subject to final closing adjustments.

The following table summarizes the preliminary allocation of the assets acquired and liabilities assumed at the acquisition date:

Restricted cash	$	1
Working capital		7,129
Property, plant and equipment		127,786
Regulatory assets		32
Other assets		114
Deferred income tax assets, net		2,793
Goodwill		9,277
Current portion of long-term liabilities		(1,840)
Current portion of derivative liabilities		(547)
Advances in aid of construction		(276)
Regulatory liabilities		(12,197)
Pension and post-retirement benefits		(3,382)
Total net assets acquired	$	128,890

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 the fair value measurements. 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 fair value of the consideration paid and the fair value of the assets acquired and liabilities assumed. The actual fair values of the assets acquired and liabilities assumed may differ from the amounts noted.

Goodwill represents the excess of the fair value of the consideration paid over the fair value of net assets acquired. The contributing factors to the amount recorded as goodwill 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. The goodwill related to Midwest Gas Utilities will be allocated to the Liberty Utilities (Central) segment.

Property, plant & equipment are amortized in accordance with regulatory requirements over the estimated useful life of the asset using the straight line method. The weighted average life is 30 years.

All costs related to the acquisition have been expensed in the consolidated Statement of Operations.

Midwest Gas Utilities contributed revenue of $5,428 and a loss of $705 to the Company's results for the three months ended September 30, 2012.

3. Business acquisitions and developments projects (continued)

(c) Proforma financial information

The supplemental pro forma financial information below was prepared using the acquisition method of accounting and is based on the historical financial information of APUC, Granite State, EnergyNorth and the Midwest Gas Utilities, reflecting results of operations for the three and nine month periods ended September 30, 2012 and 2011 on a comparative basis as though the aforementioned companies were combined as of the beginning of fiscal year 2011. The acquirees' pre-acquisition results have been added to APUC's historical results, and the totals have been adjusted for the pro forma effects of acquisition-related costs, interest expense related to the financing of the business combinations, and related income taxes.

Proforma	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Total revenue	$ 101,551	$ 112,961	$ 377,165	$ 429,948
Net earnings attributable to APUC	648	20,369	15,307	39,045
Basic net earnings per share	0.01	0.13	0.09	0.27
Diluted net earnings per share	0.01	0.13	0.09	0.27

The above unaudited pro forma financial information is presented for informational purposes only and does not purport to represent what the results would have been had the acquisition closed on the date assumed, nor is it necessarily indicative of the results that may be expected in future periods.

(d) Acquisition of U.S. wind farms

APCo has entered into agreements to acquire a 58.75% controlling interest in a 400 MW portfolio of three wind projects in the United States from Gamesa Corporación Tecnológica, S.A. ("Gamesa") for total consideration of approximately U.S. $270,000. Closing of the individual projects is subject to conditions precedent, including achievement of commencement of operations.

On July 1, 2012, APCo acquired a 51% controlling interest in one of the projects, Sandy Ridge for approximately $30,121 (U.S. $29,749). Subsequent to the end of the quarter APCo acquired an additional 7.75% interest for U.S. $4,521 bringing the total interest to 58.75% for total consideration of U.S. $34,270. The three wind projects are being acquired through American Wind Portfolio Holdings LLC. ("AWPH"), a newly formed partnership whose members include Class B members consisting of APCo (holding a 58.75% controlling interest) and Gamesa (holding a 41.25% interest) and certain Class A equity investors. In exchange for the cash contributed, the Class A members will receive a portion of the economic attributes of the facility, including Production Tax Credits ("PTCs"), allocated taxable income or loss and cash distributions, until they receive the targeted internal rate of return (the 'Flip Date'). Pursuant to the allocation rules specified in the LLC operating agreement, all operating cash flow is allocated to the Class B members until the earlier of a fixed date, or when the Class B members recover the amount of invested Class B capital. This is expected to occur between five to seven years from the initial closing date. Thereafter, 65% of operating cash flow is allocated to the Class A members until the Flip Date, which is expected to occur between eight and ten years from the initial closing date. After the initial year until the Flip Date, substantially all of the tax income and benefits generated by the partnerships are allocated to the Class A members, with any remaining benefits allocated to the Class B members.

The Class B membership held by Gamesa is recorded as non-controlling interest on the Consolidated Balance Sheet. The Company has determined that the provisions in the contractual arrangements in regards to the Class A membership represent substantive profit sharing arrangements and, as a result, the Class A membership is recorded as non-controlling interest on the Consolidated Balance Sheet. Due to the partnership's structure and the preferences in regards to distribution, the Class A non-controlling interests in earnings is measured under the HLBV method. HLBV uses a balance sheet approach, which measures the income or loss of the Class A's membership in each period by calculating the change in the amount of distribution the partners would contractually be entitled to based on a hypothetical liquidation of the book value carrying amounts of the entity at the beginning of a reporting period compared to the end of that period.

3. Business acquisitions and developments projects (continued)

(d) Acquisition of U.S. wind farms (continued)

The following table summarizes the allocation of the assets acquired and liabilities assumed at the acquisition date:

Cash	$	1,348
Property, plant and equipment		86,258
Derivative asset		1,655
Working capital		(1,348)
Asset retirement obligation		(642)
Total net assets acquired	$	87,271
Equity interests:		
APCo Class B membership interest	$	30,121
Non-controlling interests		
Class A members		28,211
Class B members		28,939
	$	87,271

Property, plant & equipment are amortized on a straight line basis over the lives of the assets, which have a weighted average life of 33 years.

Sandy Ridge contributed revenue of $696 and a loss attributable to shareholders of APUC of $586 for the three months ended September 30, 2012. The disclosure of pro forma revenue and earnings is impracticable since APCo acquired Sandy Ridge shortly after commencement of operations.

Subsequent to the quarter end, APCo paid U.S. $11,620 in relation to its ownership interest in the Senate and Minonk projects. This amount is the first payment towards the total purchase of the projects which will be made following their respective Commercial operation dates, currently expected to occur in late 2012, subject to satisfaction of certain conditions precedent.

(e) Acquisition of solar energy project

On January 4, 2012, APCo acquired rights to develop a 10 MWac solar project located near Cornwall, Ontario which has been granted a Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the contract is $4,500 plus additional contingent consideration of $3,500 that is based on achieving certain construction milestones. The transaction has been recorded as a purchase of intangible assets. Following the completion of all regulatory submissions and approvals, construction of the solar facility is expected to begin in the first half of 2013, with a commercial operation date estimated in Q4 2013.

(f) Power purchase agreement for Chaplin wind project

On February 28, 2012, APCo entered into a 25 year Power Purchase Agreement with SaskPower in connection with the development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan. The project has a targeted commercial operation date of December, 2016. The project will be constructed at an estimated capital cost of $355,000. As of September 30, 2012, the Company has incurred $430 of the estimated total capital cost. The 25 year power purchase agreement features an annual rate escalation provision of 0.6% throughout the term of the agreement.

(g) Agreement to acquire Regulated Water Utility

On July 20, 2012, Liberty Utilities entered into an agreement with United Waterworks Inc. to acquire all issued and outstanding shares of United Water Arkansas Inc. a regulated water distribution utility (the "Arkansas Utility") located in Pine Bluff, Arkansas. Total purchase price for the Arkansas Utility is approximately U.S. $28,600, 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 2013.

3. Business acquisitions and developments projects (continued)

(h) Agreement to acquire Regulated Gas Utility

On August 8, 2012, Liberty Utilities entered into an agreement with Atmos Energy Corporation ("Atmos") to acquire certain regulated natural gas distribution utility assets (the "Georgia Utility") located in the State of Georgia. Total purchase price for the Georgia Utility is approximately U.S. $140,660, 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 2013.

4. Accounts receivable

Accounts receivable as of September 30, 2012, include unbilled revenue of $7,914 (December 31, 2011 - $11,304) in the regulated utilities. The unbilled revenue is an estimate of the amount of utility revenue since the date the meters were last read.

5. Long-term investments and notes receivable

Long-term investments and notes receivable consist of the following:

	September 30, 2012	December 31, 2011
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 4,926	$ 4,926
25% of Class B non-voting shares of Cochrane Power Corporation	5,021	5,382
45% interest in the Algonquin Power (Rattle Brook) Partnership	3,776	3,784
50% interest in the Valley Power Partnership	1,554	1,676
Red Lily Subordinated loan, interest at 12.5%	6,565	6,565
Red Lily Senior loan, interest at 6.31%	11,588	13,000
Chapais Énergie, Société en Commandite interest at 10.789% and 4.91%, respectively	2,569	2,913
Silverleaf resorts loan, interest at 15.48%	1,987	2,056
Other	281	-
	38,267	40,302
Less: current portion	(523)	(482)
Total long term investments and notes receivable	$ 37,744	$ 39,820

6. Regulatory matters

The Company's 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 Company`s regulated utility operating companies are accounted for under 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.

6. Regulatory matters (continued)

Regulatory assets and liabilities consist of the following:

	September 30, 2012	December 31, 2011
Regulatory assets:		
Environmental costs	$ 55,721	$ -
Pension and post-retirement benefits	33,904	-
Storm costs deferral	5,495	-
Derivative contracts	1,987	-
Energy costs adjustment	2,856	-
Renewable energy credits	1,615	-
Rate case costs	3,421	2,161
Alternative revenue program	1,359	2,789
Asset retirement obligation	1,064	-
Other	2,218	79
Total regulatory assets	$ 109,640	$ 5,029
Less current regulatory assets	7,269	2,458
Non-current regulatory assets	$ 102,371	$ 2,571
Regulatory liabilities		
Energy costs adjustment	$ 12,598	$ 6,708
Rate adjustment mechanism	320	-
Post-retirement benefits	1,307	-
Regulatory tax liability	5,145	
Derivative liabilities	1,169	-
Removal costs recovered	56,382	14,945
Total regulatory liabilities	$ 76,921	$ 21,653
Less current regulatory liabilities	2,727	2,469
Non-current regulatory liabilities	$ 74,194	$ 19,184

The regulatory items above are not included in the utility rate base at the time the expenses are incurred or the revenue is billed. The Company records carrying charges on the regulatory balances related to energy costs, storm costs and rate adjustments mechanisms for which cash expenditures have been made and are subject to recovery or for which cash has been collected and is subject to refund. Carrying charges are not recorded on items for which expenditures have not yet been made. The Company anticipates recovering these costs in its rates concurrently with future cash expenditures. If recovery is not concurrent with the cash expenditures, the Company will record the appropriate level of carrying charges.

7. Long-term liabilities

Long term liabilities consist of the following:

	September 30, 2012	December 31, 2011
APCo		
Revolving credit facility	$ 46,719	$ -
Senior Unsecured Notes	134,799	134,778
Senior Debt Long Sault Rapids	38,369	39,033
Sanger Bonds	18,877	19,526
Senior Debt Chute Ford	3,844	4,072
Liberty Utilities		
Revolving credit facility	33,920	-
Senior Unsecured Notes:		
Liberty Utilities Co.	221,220	-
California Pacific Electric Company, LLC	68,824	71,190
Liberty Water Co	49,160	50,850
Granite State	14,748	-
Litchfield Park Service Company Bonds	11,150	11,868
Bella Vista Water Loans	1,268	1,399
	$ 642,898	$ 332,716
Less: current portion	(1,727)	(1,624)
	$ 641,171	$ 331,092

Certain long-term debt issued at a subsidiary level relating to a specific operating facility is secured by the respective facility with no other recourse to APUC, APCo or Liberty Utilities. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions/dividends to Liberty Utilities, APCo and APUC from the specific facilities.

On May 31, 2012, APCo increased the maximum availability under its senior credit facility from $120,000 to $155,000 to meet future working capital needs.

During the quarter, APCo designated the amounts drawn on its bank credit facility denominated in U.S. dollars as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of APCo's facility that is designated a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in other comprehensive income) related to the net investment, to the extent it is effective as a hedge. A foreign currency gain of $619 was recorded in other comprehensive income in the quarter.

On January 18, 2012, Liberty Utilities entered into an agreement for a senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Effective July 3, 2012, the maximum credit available under the facility is U.S. $100,000.

In July 2012, Liberty Utilities issued U.S. $225,000 of senior unsecured notes through a private placement in three tranches: U.S. $50,000, bearing an interest rate of 3.51%, maturing July 31, 2017; U.S. $115,000, bearing an interest rate of 4.49%, maturing August 1, 2022; and, U.S. $60,000, bearing an interest rate of 4.89%, maturing July 30, 2027. The notes are interest only, payable semi-annually. Liberty Utilities used the proceeds of the private placement financing to fund a portion of the acquisition of the New Hampshire and Midwest Gas Utilities (note 3(a), and (b)).

On July 3, 2012, in connection with the acquisition of Granite State, Liberty Utilities assumed U.S. $15,000 of senior unsecured long-term notes. The interest rate on these notes range from 7.30% to 7.94% and their maturity dates range from November 2023 to June 2028.

8. Convertible debentures

2012	Series 2A	Series 3	Total
Maturity date	2016 November 30	2017 September 30	
Interest rate	6.35%	7.00%	
Conversion price per share	$ 6.00	$ 4.20	
Carrying value at December 31, 2011	$ 59,726	$ 62,571	$ 122,297
Conversion to common shares (note 9(a)), net of costs	(59,729)	(360)	(60,089)
Amortization and accretion	3	-	3
Carrying amount at September 30, 2012	$ -	$ 62,211	$ 62,211
Face value at September 30, 2012	$ -	$ 62,211	$ 62,211

On February 24, 2012, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed for 10,322,518 shares of APUC (note 9(a)).

For the nine month period ended September 30, 2012, $360 of Series 3 Debentures were redeemed for 85,704 shares of APUC (note 9(a)).

9. Shareholders' capital

(a) Common shares

Number of common shares:

	Nine months ended September 30, 2012
Common shares, beginning of period	136,122,780
Conversion and redemption of convertible debentures	10,408,222
Conversion of subscription receipts	21,590,750
Issuance of shares under the dividend reinvestment and employee share purchase plans	929,230
Common shares, end of period	169,050,982

On February 24, 2012, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed for 10,322,518 shares of APUC.

For the nine month period ended September 30, 2012, $360 of Series 3 Debentures were redeemed for 85,704 shares of APUC.

In May, 2012, in connection with the acquisition of Granite State and EnergyNorth, the Company issued 12,000,000 shares at a price of $5.00 per share to Emera Inc. ("Emera") pursuant to a subscription receipt agreement. The $60,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisitions.

On June 29, 2012, in connection with the acquisition of Sandy Ridge the Company received $15,000 from Emera relating to 2,614,006 subscription receipts representing a price of $5.74 per share and issued shares relating to these subscription receipts in July 2012.

On July 31, 2012, in connection with the acquisition of the Midwest Gas Utilities the Company issued 6,976,744 shares at a price of $6.45 per share to Emera pursuant to a subscription receipt agreement. The $45,000 cash proceeds of the subscription receipts were used to fund a portion of the cost of the acquisition.

Following the above noted subscription receipts transactions, the subscriptions receipts that remain outstanding are as follows: 7,842,016 subscription receipts at a price of $5.74 per share in connection with the acquisition of the remaining U.S. wind farm projects and 8,211,000 subscription receipts issued on September 12, 2011 at a price of $4.72 per share in connection with the Company's acquisition of Emera's minority interest in Liberty Energy (California) ("Calpeco").

Subsequent to the end of the quarter, APUC issued an additional 325,341 shares under the dividend reinvestment plan.

9. Shareholders' capital (continued)

(b) Preferred shares

Subsequent to the quarter end, on November 9, 2012, APUC issued 4,800 Series A Preferred shares, at a price of $25 per share, for aggregate proceeds of $120,000 before issuance cost of $4,300.

The holders of preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.125 per share, payable quarterly, as and when declared by the Board of Directors of APUC ("Board"). The Series A Preferred shares yield 4.5% annually for the initial six-year period up to, but excluding December 31, 2018, with the first dividend payment occurring December 31, 2012. The dividend rate will reset on December 31, 2018, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 2.94%. The Series A preferred shares are redeemable at $25 per share at the option of the Company on December 31, 2018, and on December 31 of every fifth year thereafter.

The holders of Series A Preferred shares have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series B ("the Series B Preferred shares"), subject to certain conditions, on December 31, 2018, and on December 31 of every fifth year thereafter. The Series B Preferred Shares carry the same features as the Series A Preferred shares, except that holders will be entitled to receive quarterly floating-rate cumulative dividends, as and when declared by the Board, at a rate equal to the then ninety-day Government of Canada treasury bill yield plus 2.94%. The holders of Series B Preferred Shares will have the right to convert their Shares back into Series A Preferred shares on December 31, 2018, and on December 31 of every fifth year thereafter.

The Series A Preferred shares and the Series B Preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

(c) Share-based compensation

On March 8, 2012, the Board approved the grant of 1,194,606 options to senior executives of the Company. The options allow for the purchase of common shares at a price of $6.22, the market price of the underlying common share at the date of grant.

On June 19, 2012, the Board approved the grant of 69,016 options to senior executives of the Company. The options allow for the purchase of common shares at a price of $6.56, the market price of the underlying common share at the date of grant.

One-third of the options vest on each of January 1, 2013, 2014 and 2015. Options may be exercised up to eight years following the date of grant.

In 2012, 44,196 Deferred Share Units ("DSU") were issued pursuant to the election of the Directors to defer a percentage of their 2011 and 2012 Director's fee in the form of DSUs. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSUs in cash, these DSUs are accounted for as equity awards.

For the three and nine months ended September 30, 2012, APUC recorded $417 and $1,263 (2011 - $228 and $445) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at September 30, 2012, total unrecognized compensation costs related to non-vested options and share unit awards were $2,098 and $32 respectively, and are expected to be recognized over a period of 1.78 years and 1.25 years respectively.

10. Cash dividends

The Board declared a dividend on the Company's shares of $0.0775 per share payable on October 15, 2012 to the shareholders of record on September 28, 2012.

11. Income taxes

For the nine months ended September 30, 2012, the Company's overall effective tax rate was different than the statutory rate of 26.25% (2011 - 28.25%) due primarily to recognition of deferred credits, non-taxable inter-corporate dividend, higher tax rates in U.S. subsidiaries, change in valuation allowances, and non deductible expenses.

11. Income taxes (continued)

Included in deferred income tax recoveries for the three and nine months ended September 30, 2012 is $573 and $2,091 (2011- $1,875 and $5,424) related to the recognition of deferred credits from the utilization of deferred income tax assets respectively.

12. Related party transactions

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

Transactions with APMI and Senior Executives

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 and nine months ended September 30, 2012 were $82 and $245 (2011 - $82 and $245).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. During the three and nine months ended September 30, 2012, APUC incurred costs in connection with the use of the aircraft of $331 and $495 (2011 - $226 and $350) and amortization expense related to the advance against expense reimbursements of $73 and $228 (2011 - $77 and $205). At September 30, 2012, the remaining amount of the advance was $52 (December 31, 2011 - $279) 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"), a subsidiary of APUC and the legal owner of the St. Leon facility. The related holders of the Class B units received cash distributions of $59 and $214 for the three and nine months ended September 30, 2012 (2011 - $121 and $208).

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. In 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 owing to APMI is included in accrued liabilities at September 30, 2012.

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest.

As at September 30, 2012, included in amounts due from related parties is $819 (December 31, 2011 - $663) owed to APUC from APMI and included in amounts due to related parties is $1,805 (December 31, 2011 - $1,795) owed to APMI. These amounts arise from the transactions described above.

Transactions with APMI and Senior Executives (continued)

Long Sault is a hydroelectric generating facility in which APUC acquired its interest 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.

During the quarter ended March 31, 2012, APUC and APMI's Senior Executives (the "Parties") reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the fourth quarter of 2012.

Under this term sheet, it is proposed that APUC will exchange its 45% interest in the 4MW Rattlebrook hydroelectric facility (including a $0.5 million positive working capital adjustment) in return for the Parties' residual partnership interest in the Long Sault Rapids hydroelectric facility and the equity interest in the Brampton cogeneration plant. The agreement also terminates outstanding fees potentially owing to APMI in respect of the following: the historic transactions including the Sanger repowering project, the offer to acquire Clean Power Income Fund and the development of the Red Lily I wind project.

The special committee of the Board retained the services of an independent advisor to review the historic financial performance of the Rattlebrook and Long Sault Rapids facilities, provide a valuation of these assets and to provide advice to APUC in respect thereof.

12. Related party transactions (continued)

Transactions with Emera

A subsidiary of Emera provides 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, 2012 APUC paid U.S. $nil (2011 – U.S. $nil and $102) in relation to this contract. In 2011, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

For the three and nine months ended September 30, 2012, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,566 and $4,556 (2011 – U.S. $1,659 and $5,301). In 2011, 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, 2012, included in amounts due from related parties is $1,571 (December 31, 2011 - $1,612) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

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

13. 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, with the exception of those matters described below. 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 October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that the APUC subsidiary has been paying to the St. Lawrence Seaway Management Corporation ("Seaway Management") under its water lease with Seaway Management in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $5.8 million as at September 30, 2012.

Environmental matters

The normal ongoing operations and historic activities of the Company are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency and the New Hampshire Department of Environmental Services ("NHDES"). Like most other industrial companies, the gas and electric distribution utilities generates some hazardous wastes. 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.

Prior to their acquisition by Liberty Utilities, EnergyNorth and Granite State were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Company is currently investigating and remediating, as necessary, those MGP and related sites in accordance with plans submitted to the NHDES. The Company believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Company estimates the remaining cost of these MGP-related environmental cleanup activities will be $52,855 at September 30, 2012, which has been accrued as the Company's estimate of costs for known issues. Remediation costs, however, for each site may be materially higher than noted, depending upon changing technologies and regulatory standards, selected end use for each site, and actual environmental conditions encountered.

By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at September 30, 2012 the Company has reflected a regulatory asset of $55,721 for the MGP and related sites.

13. Commitments and contingencies (continued)

Environmental matters (continued)

In November, 2011, the NHDES provided a final response to the EnergyNorth's proposed remedy at the Liberty Hill Road Site in New Hampshire. In its final determination, NHDES requested that the Company proceed with implementation of a more costly remedy than was originally proposed by the Company. The Company has not accepted this determination and formally appealed the NHDES final determination in December 2011. Discussions with NHDES are on-going and appeal proceedings are set to start in early 2013. If the appeal and the NHDES discussions are unsuccessful, then this would result in an increase in environmental reserves by $1,600 and a corresponding increase in regulatory assets of the same amount compared with the balances recorded in these consolidated 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, 2012.

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 the remaining potential remedial measures involving capital expenditures to be approximately $16,400 which may be required to comply with the legislation and which would be invested over a five year period or longer.

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, 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
Purchased power	$ 40,488	$ 40,911	$ 41,761	$ 10,471	$ -	$ -	$ 133,631
Gas delivery, service and supply agreements	25,087	16,594	16,594	6,712	5,266	53,076	123,329
Long term service agreements	6,102	6,561	6,615	6,886	7,281	141,358	174,803
Capital projects	2,362	500	-	-	-	-	2,862
Operating leases	2,944	2,628	2,192	1,783	1,578	35,741	46,866
Total	**$ 76,983**	**$ 67,194**	**$ 67,162**	**$ 25,852**	**$ 14,125**	**$230,175**	**$ 481,491**

Calpeco has entered into a five year all-purpose power purchase agreement ("PPA") with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of September 30, 2012. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism. Granite State has several types of long-term contracts for the purchase of electric power. Substantially all of these contracts require power to be delivered before the Company is obligated to make payment.

14. 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. Diluted net income per share is computed using the weighted-average number of common shares and, if dilutive, potential common shares outstanding during the period. Potential common shares consist of the incremental common shares issuable upon the exercise of stock options, PSUs, DSUs, shareholders' rights and convertible debentures. The dilutive effect of outstanding stock options, PSUs, DSUs and shareholders' rights is reflected in diluted earnings per share by application of the treasury stock method while the dilutive effect of convertible debentures is reflected in diluted earnings per share by application of the as if converted method. The weighted average shares outstanding during the year are as follows:

14. Basic and diluted net earnings per share (continued)

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Weighted average shares – basic	168,977,490	119,212,025	154,378,090	111,963,782
Dilutive effect of share-based awards	663,693	252,894	547,564	191,884
Weighted average shares – diluted	169,641,183	119,464,919	154,925,654	112,155,666

For the three and nine months period ended September 30, 2012, the shares potentially issuable as a result of the convertible debentures as well as 1,263,654 and 1,703,901 stock options, respectively (2011 – 1,330,230 and 1,330,230) are excluded from this calculation as they are anti-dilutive.

15. Non-cash operating items

The changes in non-cash operating items is comprised of the following:

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Accounts receivable	$ 6,997	$ 3,012	$ 11,664	$ 139
Related party balances	(40)	1,453	(105)	105
Supplies and consumable inventory	(1,092)	(659)	(1,731)	(1,089)
Income tax receivable	(394)	-	(423)	-
Prepaid expenses	(794)	(1,396)	651	(1,327)
Accounts payable	171	(5,139)	598	(2,241)
Accrued liabilities	3,896	13,143	(5,683)	13,180
Current income tax liability	25	129	(113)	610
Net regulatory assets and liabilities	(4,055)	(489)	(1,562)	(441)
	$ 4,714	$ 10,054	$ 3,296	$ 8,936

16. Segmented information

APUC has two 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 and natural gas 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. The 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 2012, the Company changed its operational segments within Liberty Utilities to be aggregated and reported by the following geographic territories: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas Utilities and the water distribution and wastewater utilities located in Texas, Missouri and Illinois. Liberty Utilities (East) is comprised of the New Hampshire electric and gas utilities. The Company has restated the comparative items of segmented financial information to reflect the aggregation of segmented financial information adopted in the current quarter.

16. Segmented information (continued)

Operational segments

APUC's reportable segments are APCo - Renewable Energy, APCo - Thermal Energy, Liberty Utilities West), Liberty Utilities (Central) and Liberty Utilities (East). 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:

16. Segmented information (continued)
Operational segments (continued)

Three months ended September 30, 2012

	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 17,164	$ 19,145	$ 36,309	$ -	$ 36,309
Regulated gas sales and distribution	-	-	-	5,428	-	12,158	17,586	-	17,586
Regulated water reclamation and distribution	-	-	-	2,467	10,012	-	12,479	-	12,479
Non-regulated energy sales	17,807	9,773	27,580	-	-	-	-	-	27,580
Waste disposal fees	-	3,998	3,998	-	-	-	-	-	3,998
Other revenue	392	581	973	-	48	68	116	-	1,089
Total revenue	18,199	14,352	32,551	7,895	27,224	31,371	66,490	-	99,041
Operating expenses	9,425	5,106	14,531	4,259	8,558	13,869	26,686	-	41,217
Regulated electricity purchased	-	-	-	-	10,992	12,096	23,088	-	23,088
Regulated gas purchased	-	-	-	1,772	4	2,128	3,904	-	3,904
Non-regulated fuel for generation	-	3,133	3,133	-	-	-	-	-	3,133
	8,774	6,113	14,887	1,864	7,670	3,278	12,812	-	27,699
Depreciation of property, plant and equipment	(5,104)	(2,562)	(7,666)	(1,271)	(2,580)	(3,377)	(7,228)	-	(14,894)
Amortization of intangible assets	(663)	(220)	(883)	(22)	(138)	-	(160)	-	(1,043)
Administration expenses	(1,452)	(134)	(1,586)	(16)	(1,527)	-	(1,543)	(1,246)	(4,375)
Foreign exchange loss	-	-	-	-	-	-	-	(1,449)	(1,449)
Interest expense	(3,279)	(456)	(3,735)	(30)	(2,211)	(446)	(2,687)	(3,284)	(9,706)
Interest, dividend and other income	148	103	251	-	161	48	209	431	891
Write down of long lived assets	(260)	-	(260)	-	-	-	-	-	(260)
Acquisition related costs	(192)	-	(192)	-	(1,277)	(507)	(1,784)	-	(1,976)
Gain/(loss) on derivative financial instruments	(764)	-	(764)	-	-	-	-	1,220	456
Earnings / (loss) before income taxes	$ (2,792)	$ 2,844	$ 52	$ 525	$ 98	$ (1,004)	$ (381)	$ (4,328)	$ (4,657)
Capital expenditures	3,988	(1,900)	2,088	1,576	7,045	3,557	12,178	16	14,282

16. Segmented information (continued)

Operational segments (continued)

Nine months ended September 30, 2012

	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 52,463	$ 19,145	$ 71,608	$ -	$ 71,608
Regulated gas sales and distribution	-	-	-	5,428	-	12,158	17,586		17,586
Regulated water reclamation and distribution	-	-	-	6,974	28,159	-	35,133	-	35,133
Non-regulated energy sales	64,861	25,658	90,519	-	-	-	-	-	90,519
Waste disposal fees	-	11,604	11,604	-	-	-	-	-	11,604
Other revenue	1,163	1,048	2,211	-	133	68	201	-	2,412
Total revenue	66,024	38,310	104,334	12,402	80,755	31,371	124,528	-	228,862
Operating expenses	25,816	15,844	41,660	6,817	26,281	13,869	46,967	-	88,627
Regulated electricity purchased	-	-	-	-	32,436	12,096	44,532	-	44,532
Regulated gas purchased	-	-	-	1,772	4	2,128	3,904	-	3,904
Non-regulated fuel for generation	-	10,174	10,174	-	-	-	-	-	10,174
	40,208	12,292	52,500	3,813	22,034	3,278	29,125	-	81,625
Depreciation of property, plant and equipment	(13,491)	(7,539)	(21,030)	(1,881)	(8,273)	(3,377)	(13,531)	-	(34,561)
Amortization of intangible assets	(1,989)	(625)	(2,614)	(60)	(446)	-	(506)	-	(3,120)
Administration expenses	(4,688)	(760)	(5,448)	(63)	(2,876)	-	(2,939)	(5,852)	(14,239)
Foreign exchange loss	-	-	-	-	-	-	-	(1,040)	(1,040)
Interest expense	(10,467)	(1,523)	(11,990)	(63)	(5,918)	(446)	(6,427)	(6,268)	(24,685)
Interest, dividend and other income	1,541	240	1,781	-	988	48	1,036	1,684	4,501
Write down of long lived assets	(260)	-	(260)	-	-	-	-	-	(260)
Acquisition related costs	(2,474)	-	(2,474)	-	(3,426)	(507)	(3,933)	-	(6,407)
Gain/(loss) on derivative financial instruments	(2,432)	-	(2,432)	-			-	2,257	(175)
Earnings/(loss) before income taxes	$ 5,948	$ 2,085	$ 8,033	$ 1,746	$ 2,083	$ (1,004)	$ 2,825	$ (9,219)	$ 1,639
Property, plant and equipment	$ 568,741	$ 97,309	$ 666,050	$ 145,697	$ 338,628	$ 338,886	$ 823,211	$ -	$1,489,261
Intangible assets	30,150	6,258	36,408	2,603	18,480	-	21,083	-	57,491
Total assets	641,093	118,456	759,549	178,267	458,158	448,723	1,085,148	122,431	1,967,128
Capital expenditures	13,558	12,330	25,888	1,961	13,550	3,557	19,068	54	45,010

16. Segmented information (continued)
Operational segments (continued)

	Three months ended September 30, 2011								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 16,663	$ -	$ 16,663	$ -	$ 16,663
Regulated water reclamation and distribution	-	-	-	2,378	9,879	-	12,257	-	12,257
Non-regulated energy sales	19,197	12,755	31,952	-	-	-	-	-	31,952
Waste disposal fees	-	4,074	4,074	-	-	-	-	-	4,074
Other revenue	746	356	1,102	-	-	-	-	-	1,102
Total revenue	19,943	17,185	37,128	2,378	26,542	-	28,920	-	66,048
Operating expenses	6,658	5,069	11,727	1,064	8,177	-	9,241	(1)	20,967
Regulated electricity purchased	-	-	-	-	9,949	-	9,949	-	9,949
Non-regulated fuel for generation	-	5,966	5,966	-	-	-	-	-	5,966
	13,285	6,150	19,435	1,314	8,416	-	9,730	1	29,166
Depreciation of property, plant and equipment	(4,132)	(2,676)	(6,808)	(226)	(2,513)	-	(2,739)	-	(9,547)
Amortization of intangible assets	(1,019)	(334)	(1,353)	(20)	(154)	-	(174)	-	(1,527)
Administration expenses	(1,575)	(611)	(2,186)	(9)	(481)	-	(490)	(2,078)	(4,755)
Foreign exchange loss	-	-	-	-	-	-	-	1,149	1,149
Interest expense	(2,723)	(706)	(3,429)	(14)	(1,782)	-	(1,796)	(2,204)	(7,429)
Interest, dividend and other income	510	86	596	-	78	-	78	732	1,407
Acquisition related costs	-	-	-	-	(772)	-	(772)	-	(772)
Loss on derivative financial instruments	-	-	-	-	-	-	-	(3,754)	(3,754)
Earnings/(loss) before income taxes	$ 4,346	$ 1,909	$ 6,255	$ 1,045	$ 2,792	$ -	$ 3,837	$ (6,154)	$ 3,938
Capital expenditures	16,855	8,981	25,836	87	3,571	-	3,658	(18)	29,476

16. Segmented information (continued)

Operational segments (continued)

Nine months ended September 30, 2011

	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ -	$ -	$ -	$ -	$ 56,082	$ -	$ 56,082	$ -	$ 56,082
Regulated water reclamation									
and distribution	-	-	-	6,472	27,051	-	33,523	-	33,523
Non-regulated energy sales	63,750	36,083	99,833	-	-	-	-	-	99,833
Waste disposal fees	-	12,360	12,360	-	-	-	-	-	12,360
Other revenue	1,974	811	2,785	-	-	-	-	-	2,785
Total revenue	65,724	49,254	114,978	6,472	83,133	-	89,605	-	204,583
Operating expenses	21,207	16,510	37,717	3,083	24,364	-	27,447	(1)	65,163
Regulated electricity purchased	-	-	-	-	33,015	-	33,015	-	33,015
Non-regulated fuel for generation	-	16,832	16,832	-	-	-	-	-	16,832
	44,517	15,912	60,429	3,389	25,754	-	29,143	1	89,573
Depreciation of property, plant and equipment	(12,608)	(8,073)	(20,681)	(653)	(7,871)	-	(8,524)	-	(29,205)
Amortization of intangible assets	(2,337)	(2,043)	(4,380)	(60)	(450)	-	(510)	-	(4,890)
Administration expenses	(4,387)	(1,585)	(5,972)	(39)	(1,069)	-	(1,108)	(5,606)	(12,686)
Foreign exchange loss	-	-	-	-	-	-	-	1,051	1,051
Interest expense	(7,071)	(1,525)	(8,596)	(47)	(5,614)	-	(5,661)	(8,613)	(22,870)
Interest, dividend and other income	1,530	69	1,599	-	264	-	264	2,197	4,060
Acquisition related costs	-	-	-	-	(1,786)	-	(1,786)	-	(1,786)
Loss on derivative financial instruments	(1,068)	-	(1,068)	-	-	-	-	(3,217)	(4,285)
Earnings/(loss) before income taxes	$ 18,576	$ 2,755	$ 21,331	$ 2,590	$ 9,228	$ -	$ 11,818	$ (14,187)	$ 18,962
Capital expenditures	18,876	9,072	27,948	582	11,123	-	11,705	258	39,911
Acquisition of operating entities	-	-	-	904	97,322	-	98,226	-	98,226
				December 31, 2011					
Property, plant and equipment	$ 423,884	$ 155,507	$ 579,391	$ 188,562	$ 178,003	$ -	$ 366,565	$ -	$ 945,956
Intangible assets	25,863	7,088	32,951	19,565	2,753	-	22,318	-	55,269
Total assets	482,543	176,269	658,812	228,597	212,035	-	440,632	182,863	1,282,307

16. Segmented information (continued)
Operational segments (continued)

The majority of non-regulated energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2012 or 2011: Hydro Québec 17% (2011 - 18%), Manitoba Hydro 20% (2011 – 18%), and California PG&E 10% (2011 - 12%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

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, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Revenue				
Canada	$ 18,089	$ 20,341	$ 62,711	$ 65,149
United States	$ 80,952	$ 45,707	$ 166,151	$ 139,434
	$ 99,041	$ 66,048	$ 228,862	$ 204,583

	September 30, 2012	December 31, 2011
Property, plant and equipment		
Canada	$ 474, 415	$ 474,094
United States	$ 1,014,846	$ 471,862
	$ 1,489,261	$ 945,956
Intangible assets		
Canada	$ 30,150	$ 25,863
United States	$ 27,341	$ 29,406
	$ 57,491	$ 55,269
Other assets		
Canada	$ 829	$ 3,577
United States	$ 11,183	$ -
	$ 12,012	$ 3,577

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

17. Financial instruments

(a) Fair value of financial instruments

September 30, 2012

	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,990	$ 25,648	$ -	$ -	$ 25,648
Derivatives designated as cash flow hedge:					
Energy derivative contracts	4,739	4,739	-	4,739	-
Total financial assets	$ 27,729	$ 30,387	$ -	$ 4,739	$ 25,648
Long-term liabilities	642,898	794,254	-	794,254	-
Convertible debentures	62,211	99,768	99,768	-	-
Derivatives designated as cash flow hedge:					
Energy derivative contracts	687	687	-	687	-
Derivatives not designated as hedge:					
Interest rate swaps	5,354	5,354	-	5,354	-
Energy derivative contracts	2,322	2,322	-	2,322	-
Total financial liabilities	$ 713,472	$ 902,385	$ 99,768	$ 802,617	$ -

17. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

December 31, 2011

	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 24,534	$ 24,534	$ -	$ -	$ 24,534
Total financial assets	$ 24,534	$ 24,534	$ -	$ -	$ 24,534
Long-term liabilities	332,716	338,264	-	338,264	-
Convertible debentures	122,297	162,195	162,195	-	-
Derivatives designated as cash flow hedge:					
Energy derivative contracts	-	-	-	-	-
Derivatives not designated as hedge:					
Interest rate swaps	6,975	6,975	-	6,975	-
Energy derivative contracts	1,169	1,169	-	1,169	-
Total financial liabilities	$ 463,157	$ 508,603	$ 162,195	$ 346,408	$ -

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 principle 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.
- 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.

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value (a level 2 measurement) at September 30, 2012 and December 31, 2011 due to the short-term maturity of these instruments.

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 at fixed interest rates and variable rates. The estimated fair value is calculated using the current interest rates. The fair value of convertible debentures is determined using quoted market price.

The Company's Level 2 fair value derivative instruments primarily consist of swaps, options, and forward physical deals where market data for pricing inputs are observable. Level 2 pricing inputs are obtained from various market indices and utilize discounting based on quoted interest rate curves which are observable in the marketplace.

The Red Lily conversion option is measured at fair value on a recurring basis using unobservable inputs (Level 3). The fair value is based on an income approach using an option pricing model that includes various inputs such as energy yield function from wind, estimated cash flows and a discount rate of 8.5%. The Company used a discount rate believed to be most relevant given the business strategy. There was no change in fair value of $0 during the quarters ended September 30, 2012 or 2011.

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.

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 level 3 during the three or nine months ended September 30, 2012 or 2011.

17. Financial instruments (continued)

(b) Effect of derivative instruments

Derivative instruments are recognized on the balance sheet as either assets or liabilities and measured at fair value each reporting period.

(i) Commodity derivatives – Regulated Accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sales prices to regulated customers. The accounting for these derivative instruments is subject to current guidance for rate-regulated enterprises. Therefore, the fair value of these derivatives is recorded as current or long-term assets and liabilities, with offsetting positions recorded as regulatory assets and regulatory liabilities in the accompanying balance sheets. Gains or losses on the settlement of these contracts are initially deferred and then refunded to or collected from customers consistent with regulatory requirements.

The following are commodity volumes, in dekatherms ("dths") associated with the above derivative contracts:

		September 30, 2012
Physical contracts:	Gas purchases	-
Financial contracts:	Gas swaps	4,108,612
	Gas options	1,343,989
		5,452,601

The change in fair value of the regulated contracts exactly corresponds to offsetting regulatory assets and liabilities. As a result, the changes in fair value of these natural gas derivative contracts and their offsetting regulatory assets and liabilities had no earnings impact. The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the accompanying balance sheets:

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Regulatory assets:				
Gas swap contracts	$ 511	$ -	$ 511	$ -
Gas option contracts	$ 246	$ -	$ 246	$ -
Regulatory liabilities:				
Gas swap contracts	$ 1,631	$ -	$ 1,631	$ -
Gas option contracts	$ 205	$ -	$ 205	$ -

(ii) Cash flow hedges

APCo reduces the price risk on the sale of future power generation at Sandy Ridge and at one of its hydro facility no longer subject to a power purchase agreement by entering into the following long-term energy derivative contracts.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Pay floating price (per MW-hr)
207,199	May 2012 – December 2016	$ 66.73	AESO
1,144,045	January 2013 – December 2022	$ 42.86	PJM Western HUB

These contracts have been designated as cash flow hedges, with the effective portion of the change in fair value deferred to accumulated other comprehensive income, until the hedged transaction occurs and are recognized in earnings. The ineffective portion is immediately recognized in earnings.

17. Financial instruments (continued)

(b) Effect of derivative instruments (continued)

The effects on the statement of operations of derivative financial instruments designated as cash flow hedges consist of the following:

	Three months ended September 30, 2012		Three months ended September 30, 2011		Nine months ended September 30, 2012		Nine months ended September 30, 2011	
Gain recognized in OCI (effective portion)	$	1,891	$	-	$	2,147	$	-
Gain (loss) reclassified from AOCI into non-regulated energy sales	$	(125)	$	-	$	60	$	-
Gain (loss) on derivative instruments (ineffective portion)	$	-	$	-	$	-	$	-

(iii) Other derivatives

APCo provides energy requirements to various customers under contracts at fixed rates. While the production from 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.

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 for a term ending February 2014, which are net settled fixed-for-floating swaps whereby APUC will pay a fixed price and receive the floating or indexed price on a notional quantity of 110,295 MW-hrs of energy over the remainder of the contact term at an average rate of approximately $51.98 per MW-hr. The estimated fair value of these forward energy hedge contracts at September 30, 2012 was a net liability of $687 (December 31, 2011 - $1,169). These contracts are not accounted for as hedges and changes in the fair value are recorded in earnings as they occur.

For derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings. The effects on the statement of operations of derivative financial instruments not designated as cash flow hedges consist of the following:

	Three months ended September 30, 2012		Three months ended September 30, 2011		Nine months ended September 30, 2012		Nine months ended September 30, 2011	
Change in unrealized loss/(gain) on derivative financial instruments:								
Foreign exchange contracts	$	-	$	-	$	-	$	(45)
Interest rate swaps		(505)		2,112		(1,621)		2,004
Energy derivative contracts		(715)		974		(429)		(429)
Total change in unrealized loss/(gain) on derivative financial instruments	$	(1,220)	$	3,086	$	(2,050)	$	1,530
Realized loss/(gain) on derivative financial instruments:								
Foreign exchange contracts	$	-	$	-	$	(207)	$	691
Interest rate swaps		513		539		1,564		1,607
Energy derivative contracts		251		129		868		457
Total realized loss on derivative financial instruments	$	764	$	668	$	2,225	$	2,755
Loss/(gain) on derivative financial instruments	$	(456)	$	3,754	$	175	$	4,285

(c) 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.

17. Financial instruments (continued)

(c) Risk management (continued)

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, short term investments, accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by 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 Utility Services business unit which consists of water and wastewater utilities and an electric utility in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $9,451 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. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at September 30, 2012 the Company's exposure to credit risk for these financial instruments was as follows:

	September 30, 2012	
	Canadian $	**US $**
Cash and cash equivalents and restricted cash	$ 4,905	$ 18,862
Short term investments	833	-
Accounts receivable	10,660	57,548
Allowance for Doubtful Accounts	-	(4,246)
Notes Receivable	20,826	2,201
	$ 37,224	$ 74,365

There are no material past due amounts in accounts receivable.

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 at September 30, 2012, in addition to cash on hand of $16,395 the Company had $120,436 available to be drawn on its senior debt facilities. The senior credit facilities contain 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	$ 1,727	$ 84,589	$ 14,612	$ 541,970	$ 642,898
Convertible debentures	-	-	62,211	-	62,211
Advances in aid of construction	584	-	-	70,929	71,513
Interest on long term debt	38,652	70,163	64,988	119,686	293,489
Accounts payable and due to related parties	22,037	-	-	-	22,037
Accrued liabilities	58,278	-	-	-	58,278
Derivative financial instruments:					
Interest rate swaps	2,044	3,310	-	-	5,354
Energy swaps	444	2,079	-	-	2,523
Capital lease payments	156	166	-	-	322
Other obligations	4,141	-	-	11,164	15,305
Total obligations	$ 128,063	$ 160,307	$ 141,811	$ 743,749	$ 1,173,930

17. Financial instruments (continued)

Foreign currency risk

The Company periodically uses a combination of foreign exchange forward contracts and spot purchases to manage its foreign exchange exposure on cash flows generated from the U.S. operations. APUC only enters into foreign exchange forward contracts with major Canadian financial institutions having a credit rating of A or better, thus reducing credit risk on these forward contracts.

At September 30, 2012 and December 31, 2011, the Company had no outstanding forward foreign exchange contracts.

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, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

In connection with the project debt at the St. Leon facility which was repaid in 2011, APCo previously entered into an interest rate swap to hedge the floating interest rate on the project debt. This swap was not terminated when the St. Leon debt was repaid. Under the terms of the swap, the Company pays a fixed interest rate of 4.47% on a notional amount of $65.3 million and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At September 30, 2012, the estimated fair value of the interest rate swap was a liability of $5,354 (December 31, 2011 – liability of $6,975). This interest rate swap is not being accounted for as a hedge and consequently, changes in fair value are recorded in earnings as they occur.

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