Algonquin Power & Utilities Corp.

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2014

ALGONQUIN
Power & Utilities Corp.

MANAGEMENT DISCUSSION & ANALYSIS

(All monetary amounts are in thousands of Canadian dollars, except per share 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 months ended March 31, 2014. The Management Discussion & Analysis ("MD&A") should be read in conjunction with APUC's interim unaudited consolidated financial statements for the three months ended March 31, 2014 and 2013. 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 May 8, 2014.

CAUTION CONCERNING FORWARD-LOOKING STATEMENTS AND NON-GAAP MEASURES

Forward-looking statements

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.

Non-GAAP Financial Measures

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA"), "adjusted funds from operations", "per share adjusted net earnings", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales", are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share adjusted net earnings", "per share cash provided by adjusted funds from operations", Adjusted EBITDA, "net energy sales" and "net utility sales" are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share adjusted net earnings", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales". 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 adjusted net earnings", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales" and "net utility sales" can be found throughout this MD&A. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC.

Use of Non-GAAP Financial Measures

Adjusted EBITDA

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 (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, unrealized gains or losses on derivative financial instruments, non-cash write downs of intangibles and property, plant and equipment, earnings attributable to non-controlling interests, gains or losses on foreign exchange, earnings or loss from discontinued operations and other infrequent items unrelated to normal ongoing operations. APUC adjusts for these factors as they are typically 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.

Adjusted 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 funding requirements. APUC uses adjusted net earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, unrealized gains or losses on derivative financial instruments and interest rate swaps, acquisition costs, litigation expenses, non-cash write downs of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other infrequent items unrelated to normal operations 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.

Adjusted funds from operations

Adjusted funds from operations is a non-GAAP metric used by investors to compare cash flows from operating activities 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. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses, cash provided or used in discontinued operations. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted funds from operations to assess its performance without the effects of (as applicable) changes in working capital balances, acquisition expenses, litigation expenses, cash provided or used in discontinued operations and other infrequent items unrelated to normal operations affecting cash from operations 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 cash flows from operating activities as determined in accordance with GAAP.

Net energy sales

Net energy sales is a non-GAAP metric used by investors to identify revenue after commodity costs used to generate revenue where revenue generally is increased or decreased in response to increases or decreases in the cost of the commodity to produce that revenue. APUC uses net energy sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the revenue that is charged. APUC believes that analysis and presentation of net energy sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net utility sales

Net utility sales is a non-GAAP metric used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodities are generally included as a pass through in rates to its utility customers. APUC uses net utility sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by the utility customer. APUC believes that analysis and presentation of net utility sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

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's current quarterly dividend to shareholders is $0.085 per share or $0.34 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 utility 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 and wastewater collection utility systems.

Algonquin Power Co.

APCo generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable power generation and clean energy 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 125 MW. APCo owns or has interests in wind powered generating stations with a combined generating capacity of 650 MW. APCo owns a solar energy facility with approximately 10 MW of installed generating capacity. Approximately 82% 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 14 years. All of the electrical output from the solar facility is sold pursuant to long term Power purchase agreements ("PPA") with a major utility with a remaining contract life of 20 years.

APCo owns or has interests in thermal energy facilities with approximately 350 MW of installed generating capacity. Approximately 93% 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 6 years.

APCo also has a pipeline of development projects that between 2014 and 2016 will add approximately 323 MW of generation capacity from wind powered generating stations and approximately 20 MW from photovoltaic solar powered generation stations with an average contract life of 23 years.

Liberty Utilities Co.

Liberty Utilities is a diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services to approximately 480,000 connections. 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. Liberty Utilities reports the performance of its utility operations through 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 and related generation assets (the "CalPeco Electric System") serve approximately 48,300 electric connections in the State of California. Liberty Utilities (West) region's regulated water and wastewater utility systems serve approximately 68,500 water and wastewater connections located in the State of Arizona.

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 86,000 natural gas connections located in the States of Missouri, Illinois, and Iowa. Liberty Utilities (Central) region's regulated water distribution and wastewater collection utilities serve approximately 29,100 water and wastewater customers located in the States of Arkansas, 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, and regulated natural gas distribution utility systems located in the States of Georgia and Massachusetts. Liberty Utilities provides regulated local electrical utility services to approximately 43,900 electric connections in the state of New Hampshire; and regulated local gas distribution utility services to approximately 204,300 natural gas connections located in the states of Georgia, New Hampshire and Massachusetts.

MAJOR HIGHLIGHTS

2014 Corporate Highlights

Issuance of $100 million Preferred Shares

On March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D (the "Series D Shares") at a price of $25 per share, for aggregate gross proceeds of $100 million. The Series D shares will yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities and for general corporate purposes.

2014 Liberty Utilities Highlights

Granite State Electric System Rate Proceedings

On January 22, 2014, Liberty Utilities (Granite State Electric) Corp. entered a settlement with the New Hampshire Public Utilities Commission Staff in connection with its rate application filed on March 29, 2013. The settlement will provide for a rate increase of U.S. $10.9 million consisting of U.S. $9.8 million in base rates and an additional U.S. $1.1 million for incremental capital expended after the test year. In addition, the settlement allows for a one time recovery of rate case expenses of U.S. $0.4 million. The settlement was approved on March 17, 2014 with the new permanent rates effective as of April 1, 2014.

2014 Algonquin Power Co. Highlights

Acquisition of the Remaining 40% of a 400 MW Wind Power Portfolio

On March 31, 2014, APCo acquired from Gamesa Wind US, LLC ("Gamesa") the remaining 40% of the Class B partnership units of the entity which owns a three facility 400 MW wind power portfolio (the "U.S. Wind Portfolio") in the United States for total consideration of approximately U.S. $115.0 million. As a result of the transaction, APCo now owns 100% of the Class B partnership units of the entity that owns the U.S. Wind Portfolio.

APCo originally acquired 60% of the Class B units of the entity which owns the U.S. Wind Portfolio in 2012. The U.S. Wind Portfolio is a 400 MW wind portfolio consisting of three facilities, Minonk (200MW), Senate (150MW), and Sandy Ridge (50MW) located in the states of Illinois, Texas, and Pennsylvania, respectively. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts.

Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, APCo completed the construction of its 10 MWac solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014 for a total capital cost of approximately $44.7 million. The facility represents the first solar project in APCo's portfolio. The facility is expected to generate approximately 14,400 MW-hrs of electricity annually with the power sold under a 20 year FIT Power Purchase Agreement with the Ontario Power Authority.

APCo $200 million Senior Unsecured Debentures

On January 17, 2014, APCo issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "APCo Debentures") pursuant to a private placement in Canada and the United States. The APCo Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, APCo entered into a fixed for fixed cross currency swap, coterminous with the APCo Debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

Net proceeds were used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under its bank credit facility and for general corporate purposes.

Energy From Waste Facility

On April 4, 2014, the Company completed the previously disclosed sale of the assets of the EFW and BCI Thermal Facilities for proceeds approximating the carrying value of the net assets on the Consolidated Balance Sheet of the Company as at March 31, 2014.

2014 THREE MONTH RESULTS FROM OPERATIONS

Key Selected First Quarter Financial Information

(millions of dollars except per share information)	Quarter ended March 31 2014		Quarter ended March 31 2013	
Revenue	$	**343.5**	$	193.3
Adjusted EBITDA [1,3]		**97.5**		62.8
Cash provided by operating activities		**14.8**		(4.7)
Adjusted funds from operations[1,3]		**82.7**		47.7
Net earnings attributable to Shareholders from continuing operations		**35.6**		20.3
Net earnings attributable to Shareholders		**35.9**		19.2
Adjusted net earnings[1,3]		**36.8**		19.6
Dividends declared to Common Shareholders		**17.9**		15.9
Weighted Average number of common shares outstanding		**206,777,996**		200,666,444
Per share				
Basic net earnings/(loss) from continuing operations	$	**0.16**	$	0.09
Basic net earnings/(loss)	$	**0.17**		0.09
Adjusted net earnings[1,2,3]	$	**0.17**	$	0.09
Diluted net earnings/(loss)	$	**0.16**	$	0.09
Cash provided by operating activities [1,2,3]	$	**0.07**	$	(0.02)
Adjusted funds from operations[1,2,3]	$	**0.39**	$	0.23
Dividends declared to Common Shareholders	$	**0.09**	$	0.08
Total Assets		**3,652.7**		3,476.5
Total Liabilities[4]		**1,409.3**		1,255.5

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. (see "Non-GAAP Financial Measures")

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 Includes Long-term liabilities and current portion of long-term liabilities.

For the three months ended March 31, 2014, APUC experienced an average U.S. exchange rate for the quarter of approximately $1.104 as compared to $1.009 in the same period in 2013. 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 March 31, 2014, APUC reported total revenue of $343.5 million as compared to $193.3 million during the same period in 2013, an increase of $150.2 million. The major factors resulting in the increase in APUC revenue in the three months ended March 31, 2014 as compared to the corresponding period in 2013 are set out as follows:

		Quarter ended March 31, 2014 (millions)
Comparative Prior Period Revenue	$	193.3
Significant Changes:		
Liberty Utilities:		
West – Implementation of decoupling mechanism and lower electricity costs		(0.9)
Central – Revenue increase due to the acquisition of the Pine Bluff Water System and increased customer demand in the Midstates Gas Systems.		9.5
East – Revenue increase due to the acquisition of the Peach State Gas System and the New England Gas System and increased customer demand along with higher electricity and gas rates at the Granite State Electric System and the EnergyNorth Gas System		102.0
APCo:		
Renewable		
Increased overall wind resources offset by periodic hedge settlement production shortfalls at the Minonk, Senate, and Sandy Ridge Wind Facilities		(1.6)
Sale of Renewable Energy Credits generated from the U.S. Wind Facilities		1.6
Effect of hydrology resource compared to comparable period in prior year		(0.9)
St. Leon Wind Facilities - increased wind resource		1.8
Increased customer load at AES		3.6
Thermal		
Increased average prices and demand at the Windsor Locks Thermal Facility		4.5
Impact of the stronger U.S. dollar		28.8
Other		1.8
Current Period Revenue	$	343.5

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

Adjusted EBITDA for the three months ended March 31, 2014 totalled $97.5 million as compared to $62.8 million during the same period in 2013, an increase of $34.7 million or 55.3%. The increase in Adjusted EBITDA was primarily due to lower than seasonal temperatures increasing demand from customers at Liberty's natural gas and electric systems, acquisitions completed in 2013, impact of rate case settlements, and a stronger U.S. dollar. 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 March 31, 2014, net earnings attributable to Shareholders from continued operations totalled $35.6 million as compared to $20.3 million during the same period in 2013, an increase of $15.3 million. The increase was due to $30.8 million in increased earnings from operating facilities, $1.3 million due to an increase in foreign exchange gain, $0.3 million due to a gain on sale of assets, $0.2 million in decreased acquisition costs, and $2.7 million in decreased allocations of earnings to non-controlling interests as compared to the same period in 2013. These items were partially offset by $6.0 million in increased depreciation and amortization expense, $2.9 million in increased administration charges, $4.0 million in increased interest expense, $1.0 million in decreased gains from derivative instruments, and $5.5 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses)* as compared to the same period in 2013.

For the three months ended March 31, 2014, net earnings (including discontinued operations) attributable to Shareholders totalled $35.9 million as compared to net earnings attributable to Shareholders of $19.2 million during the same period in

2013, an increase of $16.7 million. Net earnings per share totalled $0.17 for the three months ended March 31, 2014, as compared to net earnings per share of $0.09 during the same period in 2013.

During the three months ended March 31, 2014, cash provided by operating activities totalled $14.8 million or $0.07 per share as compared to cash used by operating activities of $4.7 million, or $0.02 per share during the same period in 2013. During the three months ended March 31, 2014, adjusted funds from operations totalled $82.7 million or $0.39 per share as compared to adjusted funds from operations of $47.7 million, or $0.23 per share during the same period in 2013. The change in adjusted funds from operations in the three months ended March 31, 2014, is primarily due to increased earnings from operations, as compared to the same period in 2013.

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.

APCo: Renewable Energy Division

	Long Term Average Resource	Three months ended March 31 2014	2013
Performance (GW-hrs sold)			
Hydro Facilities:			
Ontario Region[6]	**37.1**	**37.5**	7.9
Quebec Region	**57.4**	**48.6**	62.6
Maritime Region	**35.7**	**33.7**	41.3
Western Region	**9.6**	**12.4**	9.6
	139.8	**132.2**	121.4
Wind Facilities:			
Manitoba Region	**121.4**	**132.9**	104.2
Saskatchewan Region[1]	**23.2**	**27.5**	20.9
Pennsylvania Region[2]	**47.1**	**44.7**	44.8
Illinois Region[3]	**310.3**	**312.0**	283.8
Texas Region[4]	**151.3**	**147.7**	145.3
	653.3	**664.8**	599.0
Total	**793.1**	**797.0**	720.4

	2014	2013
Revenue	(millions)	(millions)
Energy sales [7]	**$ 44.1**	$ 38.8
Less:		
Cost of Sales – Energy[5]	**(10.5)**	(2.4)
Net Energy Sales	**$ 33.6**	$ 36.4
Renewable Energy Credits	**2.4**	0.7
Other Revenue	**0.6**	—
Total Net Revenue	**$ 36.6**	$ 37.1
Expenses		
Operating expenses	**(15.6)**	(8.9)
Interest and Other income	**0.4**	0.4
Realized gain/(loss) on AES hedges[8]	**4.0**	0.7
HLBV income/(loss)	**8.5**	5.0
Division operating profit	**$ 33.9**	$ 34.3

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 under contract and has an option to acquire a 75% equity interest in the facility in 2016.

2 Represents the operations of the Sandy Ridge Wind Facility

3 Represents the operations of the Minonk and the Shady Oaks Wind Facilities. Production at the Shady Oaks was 112.7 GWhrs in the 3 month period ended March 31, 2014. Production at Shady Oaks can be subject to congestion related curtailment by the independent system operator but in this case compensation is expected to be received for lost energy sales.

4 Represents the operations of the Senate Wind Facility.

5 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 unaudited interim consolidated Financial Statements, these amounts are included in operating expenses.

6 APCo's Long Sault hydro facility was offline during most of the first nine months of 2013 but with lost revenue covered by insurance. See below for additional commentary.

7 Prior year comparative restated to conform with current presentation. Reclassification of certain sales by AES to the Thermal Energy Division to attribute revenues to point of generation.

8 See Financial statements note 20(b)(iv)

2014 First Quarter Operating Results

For the quarter ended March 31, 2014, the Renewable Energy Division produced 797.0 GW-hrs of electricity, as compared to 720.4 GW-hrs produced in the same period in 2013, an increase of 10.6%. The increased generation is primarily due to stronger wind resource and full production in the Ontario region for the quarter compared to the previous year where the Long Sault Hydro Facility was off line for the full quarter. This level of production represents sufficient renewable energy to supply the equivalent of 177,200 homes on an annualized basis with renewable power. As a result of renewable energy production, the equivalent of 438,350 tons of CO_2 gas was prevented from entering the atmosphere in the first quarter 2014.

During the quarter ended March 31, 2014, the division generated electricity equal to 101.5% of long-term projected average resources (wind and hydrology) as compared to 94.2% during the same period in 2013 (as adjusted for the effect of the unplanned outage at APCo's Long Sault generating facility). In the first quarter of 2014, the Manitoba, Saskatchewan and Western regions produced 9% to 29% above long-term average resources, while Illinois, Texas and Ontario regions achieved production approximately at long-term averages. Pennsylvania, Maritime and Quebec regions produced 5% to 15% lower than long-term average resources.

For the quarter ended March 31, 2014, revenue from energy sales in the Renewable Energy Division totalled $44.1 million, as compared to $38.8 million during the same period in 2013, for an increase of $5.3 million. As the purchase of energy by AES is a significant revenue driver and component of variable operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's sales results. For the quarter ended March 31, 2014, net energy sales in the Renewable Energy Division totalled $33.6 million, as compared $36.4 million during the same period in 2013.

Revenue from generation at APCo's hydro facilities located in the Ontario, Quebec and Western regions totalled $8.9 million as compared to $9.9 million during the same period in 2013 (including business interruption insurance proceeds for the Long Sault facility). The decrease is mainly attributed to low flows due to the extremely cold weather this winter, as compared to the first quarter of 2013. Revenue from APCo's hydro facility located in the Maritime region decreased $0.2 million primarily due to lower hydrology.

Revenue from APCo's wind facilities located in the Manitoba region increased by $1.8 million due to higher wind resources at the St. Leon Wind facilities. Revenues from APCo's U.S. wind facilities located in Illinois, Pennsylvania and Texas regions decreased by $1.6 million caused primarily by unfavorable hedge settlements under the Minonk, Senate and Sandy Ridge power hedges caused by periodic production shortfalls and a high spot power price caused by the unusually cold weather early in the quarter. This was offset by increased overall production due to a higher wind resource and a more favorable exchange rate.

For the three months ended March 31, 2014, revenue at AES increased $4.1 million or 85.9% primarily due to increased customer load served. Revenue at AES primarily consists of wholesale deliveries to local electric utilities, retail sales to commercial and industrial customers in Northern Maine, merchant sales of production in excess of committed customer deliveries from the Tinker Facility and other revenue.

For the quarter ended March 31, 2014, energy purchase costs by AES totalled $10.5 million as compared to $2.4 million during the same period in 2013, an increase of $8.1 million. AES' increased energy purchase costs for the quarter ended March 31, 2014 was primarily due to a higher volume of energy purchases from external suppliers, at higher average prices.

During this period, AES purchased approximately 60.6 GW-hrs of energy at market and fixed rates averaging U.S. $97 per MW-hr. During the quarter, the Maritime region generated approximately 32% of the load required to service its customers as well as AES' customers, as compared to 61% in the same period in 2013. To mitigate the risk of higher average energy prices as was experienced in the quarter, AES had previously entered into certain power hedges as part of its risk mitigation strategies. During the quarter a gain of $4.0 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments on the Consolidated Statement of Operations.

For the quarter ended March 31, 2014, REC revenue totalled $2.4 million as compared to $0.7 million in the same period in 2013, an increase of $1.7 million largely attributable to increased market pricing in the Illinois and Pennsylvania regions. REC units are generated at a ratio of one REC unit per one MWHr generated and are sold in the market in which the REC is generated. For the quarter ended March 31, 2014, REC units and related revenues were generated at the Sandy Ridge, Minonk, Senate and Shady Oaks Wind Facilities.

The Red Lily I Wind Facility located in Saskatchewan produced 27.5 GW-hrs of electricity for the quarter ended March 31, 2014. 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 revenue from energy sales. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the quarter ended March 31, 2014, APCo earned fees of $0.6 million (which is classified as other revenue) and interest income of $0.4 million from Red Lily I Wind Facility.

For the quarter ended March 31, 2014, operating expenses excluding energy purchases totalled $15.6 million, as compared to $8.9 million during the same period in 2013, an increase of $2.7 million. The increase was primarily attributable to: the appreciation of the U.S. dollar ($1.6 million), cost of RECs contracted in the first quarter of 2014 but produced in the fourth quarter of 2013 ($0.5 million), increased market balancing charges in the Illinois and Texas regions ($0.5 million), increased water lease payments due to increased hydro production and increased property taxes.

For the quarter ended March 31, 2014, interest and other income totalled $0.4 million, consistent with the same period in 2013. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility. This amount is included as part of APCo's earnings from its investment in Red Lily I Wind Facility, as discussed above.

Hypothetical Liquidation at Book Value ("HLBV") income represents the value of net tax attributes primarily related to electricity production generated by APCo in the period from certain of its U.S. wind power generation facilities. The value of net tax attributes generated in the quarter ended March 31, 2014, amounted to an approximate HLBV income of $8.5 million as compared $5.0 million in the prior year primarily resulting from a stronger US dollar exchange rate, increased overall production, and a higher income allocation to APUC due to the reduced economic interest in the projects attributable to tax equity.

For the quarter ended March 31, 2014, the Renewable Energy Division's operating profit totalled $33.9 million, as compared to $33.6 million during the same period in 2013, representing an increase of $0.3 million. As a result of the stronger U.S. dollar operating profit increased by $0.8 million.

APCo: Thermal Energy Division

	Three months ended March 31, 2014			Three months ended March 31, 2013		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance(GW-hrs sold)	**32.7**	**32.0**	**64.7**	30.0	34.4	64.4
Performance(steam sales – billion lbs)	**201.2**	**—**	**201.2**	200.1	—	200.1
(all amounts in millions)						
Revenue						
Energy/steam sales	**$ 11.0**	**$ 3.4**	**$ 14.4**	**$ 5.5**	**$ 2.6**	**$ 8.1**
Less:						
Cost of Sales – Fuel	**(8.0)**	**(1.8)**	**(9.8)**	(3.7)	(1.4)	(5.1)
Net Energy/Steam Sales	**$ 3.0**	**$ 1.6**	**$ 4.6**	$ 1.8	$ 1.2	$ 3.0
Other revenue	**0.6**	**0.2**	**0.8**	0.2	0.4	0.6
Total net revenue	**$ 3.6**	**$ 1.8**	**$ 5.4**	$ 2.0	$ 1.6	$ 3.6
Expenses						
Operating expenses	**(1.3)**	**(1.0)**	**(2.3)**	**(1.2)**	**(1.4)**	**(2.6)**
Facility operating profit	**$ 2.3**	**$ 0.8**	**$ 3.1**	$ 0.8	$ 0.2	$ 1.0
Interest and other income			**(0.2)**			0.2
Divisional operating profit			**$ 2.9**			$ 1.2

APCo's Sanger and Windsor Locks Thermal 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 the two facilities in the average landed cost for natural gas and may result in the facilities showing differing costs per unit compared to each other and 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.

2014 First Quarter Operating Results

Production data, revenue and expenses have been adjusted to remove the results of the EFW Facility and BCI Facility which is now disclosed as discontinued operations. See Financial Statement note 12 for details.

For the three months ended March 31, 2014, the Thermal Energy Division produced 64.7 GW-hrs of electrical energy as compared to 64.4 GW-hrs of electrical energy in the comparable period of 2013. The increase in electrical energy production at the Windsor Locks facility was primarily due to higher energy sales to the ISO NE electricity market as a result of favorable pricing which was driven by seasonally low temperatures. This is partially offset by decreased production at Sanger due to a planned outage limiting the run hours during the first quarter of 2014.

For the three months ended March 31, 2014, the Thermal Energy Division's operating profit was $2.9 million as compared to $1.2 million in the same period in 2013, an increase of $1.7 million. The Windsor Locks Thermal Facility contributed $2.3 million, while the Sanger Thermal Facility contributed $0.8 million of operating profit during the three months ended March 31, 2014 as compared to $0.8 million and $0.2 million, respectively during the same period in the prior year. Interest and other income for the three months ended March 31, 2014 was a loss of $0.2 million as compared to income of $0.2 million during the same period in the prior year. The reduction is primarily due to a decrease of $0.4 million in lower equity income received from the Valley Power Thermal Facility. As a result of the stronger U.S. dollar operating profit increased by $0.3 million. Detailed results of each facility are described below.

Windsor Locks

For the three months ended March 31, 2014, the Windsor Locks Thermal Facility sold 201.2 billion lbs of steam as compared to 200.1 billion lbs of steam and 32.7 GW-hrs of electricity as compared to 30.0 GW-hrs of electricity in the comparable period of 2013.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of $11.0 million, as compared to $5.5 million in the same period in 2013. The increase in electricity / steam sales is attributed to a higher average price for gas and a higher energy production as a result of the better ISO NE electricity market price driven by seasonally low temperatures. Gas costs for the period were $8.0 million as compared to $3.7 million in the same period in 2013. The increase in gas costs is a result of a 90% increase on the average landed cost of natural gas per MMBTU and a 15% increase in the volume of natural gas consumed, as compared to the same period in 2013.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended March 31, 2014, net sales at the Windsor Locks Thermal Facility totalled $3.0 million, as compared to $1.8 million during the same period in 2013, an increase of $1.2 million resulting from increased volume of electricity and steam sales.

Operating expenses, excluding natural gas costs were $1.3 million which was consistent with the same period in 2013. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended March 31, 2014 was $2.3 million as compared to $0.8 million in the same period in 2013, an increase of $1.5 million.

Sanger

The Sanger Thermal Facility's operating profit was driven by energy/steam sales of $3.4 million as compared to $2.6 million in the same period in 2013, an increase of $0.8 million. The increase in energy/steam sales is attributed primarily to $0.5 million in increased gas prices which is primarily a pass through to customers as it is reflected in higher market prices as compared to the same period in 2013 and a better achieved efficiency then contracted. Capacity revenues remained unchanged at $0.9 million. Gas costs for the period were $1.8 million as compared to $1.4 million in the same period in 2013. The increase in gas costs is due to a 44% increase in the average cost of natural gas per MMBTU as compared to the same period in 2013. This is offset by a 7.6% decrease in the volume of natural gas consumed due to planned outage in the first quarter of 2014.

As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales' (see non-GAAP Financial Measures) as an appropriate measure of the division's results. For the three months ended March 31, 2014, net energy sales at the Sanger Thermal Facility totalled $1.6 million, as compared to $1.2 million during the same period in 2013, an increase of $0.4 million.

Operating expenses, excluding natural gas costs were $1.0 million as compared to $1.4 million in the same period in 2013. The $0.2 million decrease in operating expenses was attributable to lower costs for maintenance and supplies. The Sanger Thermal Facility's resulting net operating income for the three months ended March 31, 2014 was $0.8 million as compared to $0.2 million in the same period in 2013, an increase of $0.6 million.

APCo: Development Division

The Development Division works to identify, develop and construct new power generating facilities, as well as to identify, and acquire, operating projects that would be complementary and accretive to APCo's existing portfolio.

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-hrs
Chaplin Wind [1]	Saskatchewan	177	$	340.0	2016	25	720.0
Amherst Island [1]	Ontario	75	$	230.0	2015	20	247.0
Val Eo - Phase I [1,3,4]	Quebec	24	$	70.0	2015	20	66.0
Morse Wind [1]	Saskatchewan	23	$	81.3	2015	20	104.0
Bakersfield Solar[1, 5]	California	20	$	64.7	2015	20	53.3
St. Damase - Phase I [1,2,4]	Quebec	24	$	65.0	2014	20	76.9
Total		**343**	**$**	**851.0**			**1,267.2**

1 PPA signed

2 The St. Damase project is being developed in two phases: Phase I of the project (24MW) will be erected in 2014 and the 101MW Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

3 The Val Eo project is being developed in two phases: Phase I of the project (24MW) will be erected in 2015 and the 101 MW Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

4 Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the St. Damase and Val-Eo wind projects.

5 Total cost of the project is expected to be approximately $58.5 million in U.S. dollars.

6 Revised wind resource report utilizing data from 100m met tower resource measurement campaign indicated a P50 energy estimate of 76.9 compared to previous estimate of 78.7.

Chaplin Wind Project

In 2012, APCo entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

In March 2014, after review of initial screening and review of the proposed layout, the project was deemed a development by the Environmental Assessment Branch, and a detailed environmental review is currently underway. As a result of continuing development work, the expected capital costs of the project have been reduced to $340 million from the original estimate of $355 million. To optimize the returns associated with the project, APCo intends to enter into a partnership agreement using a similar structure to what was utilized in the development of the Red Lily I facility. This would involve building the project in two phases, an initial test turbine phase followed by an infill phase constructed after completion of a successful test turbine phase.

Morse Wind Project

The 23MW project is to be constructed near Morse, Saskatchewan, approximately 180 km west of Regina. The project has additional land under lease to facilitate future expansion. The Project has a 23MW PPA with SaskPower.

In the first quarter of 2014, APCo signed a turbine supply agreement with a large turbine manufacturer. Based on the final turbine selected the total annual energy production for the Morse Wind Project is expected to be 104.0 GW-hrs. The contract rate is set at $104.02 per MW-hr for the first full year of operations, which APCo expects to occur in 2015, with an annual escalation provision of 2% over the expected 20 year term.

Saint-Damase Wind Project

Phase one of the Saint-Damase Wind Project is located in the local municipality of Saint-Damase, which is within the regional municipality of Les Maskoutains. The project is a 24MW facility located near St. Damase, Quebec in a partnership with the Municipality of Saint-Damase. The Saint-Damase wind project has signed a 20 year PPA with Hydro Quebec and has projected capital costs of $65 million. On June 25, 2013, the partnership executed an interconnection agreement with Hydro Quebec. The permitting and the environmental impact assessment are completed and the construction of the first project phase started in late first quarter of 2014. Commercial operation for the project expected to commence in Q1 2015.

The environmental impact assessment for the project has been reviewed and has received the provincial minister’s decree allowing the project to proceed with construction. APCo has entered into agreements for the supply of wind turbines, as well as balance of plant construction.

It is believed that the first 24MW phase of the Saint-Damase Wind Project will qualify as Canadian Renewable and Conservation Expense and therefore the project will be entitled to a refundable tax credit equal to approximately $20.5 million. It is contemplated that a request for a PPA in respect of Phase II of the project will be submitted to Hydro Quebec pursuant to its current request for proposals and if successful would proceed based on the results achieved in Phase I.

Cornwall Solar Project Update

Construction of the project is now complete and commercial operation was achieved on March 27, 2014. The Cornwall Solar Project is anticipated to have energy production of 14.4 GW-hrs/year. The Cornwall Solar Project has been granted a 10MW 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.

Bakersfield Solar Project

APCo has completed the acquisition for the development rights to a 20 MWac solar powered generating station located in Kern County, California. Following commissioning, the Bakersfield Solar Project is expected to generate 53.3 GW-hrs of energy per year. All energy from the project will be sold to PG&E pursuant to a 20 year agreement. APCo is currently in final negotiations of a partnership agreement with a third party (the "Tax Partner") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. It is anticipated that the total expected capital costs for the project of U.S. $58.5 million will be funded approximately 65% by APCo and the balance by the Tax Partner. Construction of the project is anticipated to commence in the second quarter of 2014 with a commercial operations date expected to occur in late 2014.

LIBERTY UTILITIES

Liberty Utilities is a national diversified rate regulated utility providing electricity, natural gas, water distribution and wastewater collection utility services in the U.S. Liberty Utilities' strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. Liberty Utilities believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type	March 31, 2014		March 31, 2013	
	Assets	Connections	Assets	Connections
	U.S. $ (millions)		U.S. $ (millions)	
Electricity	$ 282.4	92,200	$ 256.8	90,700
Natural Gas	663.9	290,300	399.7	172,500
Water and Wastewater	233.4	97,600	234.8	96,300
Total	$ 1,179.7	480,100	$ 891.3	359,500
Accumulated Deferred Income Taxes	$ 90.8		$ 63.7	

Liberty Utilities reports the performance of its utility operations by geographic region – West, Central, and East

The Liberty Utilities (West) region is comprised of regulated electrical and water distribution and wastewater collection utility systems and serves approximately 116,800 connections in the states of Arizona and California.

The Liberty Utilities (Central) region is comprised of regulated natural gas and water distribution and wastewater collection utility systems and serves approximately 115,100 connections located in the states of Arkansas, Illinois, Iowa, Missouri, and Texas.

The Liberty Utilities (East) region is comprised of regulated natural gas and electric distribution utility systems and serves approximately 248,200 connections located in the states of Georgia, Massachusetts, and New Hampshire.

Liberty Utilities: West Region

	Three months ended March 31,	
	2014	**2013**
Average Active Electric Connections For The Period		
Residential	41,900	41,400
Commercial and Industrial	5,700	5,555
Total Average Active Electric Connections For The Period	**47,600**	**46,955**
Average Active Number of Water Connections For The Period		
Wastewater connections	31,400	30,500
Water distribution connections	34,400	33,600
Total Average Active Water Connections For The Period	**65,800**	**64,100**
Customer Usage (GW-hrs)		
Residential	80.7	89.3
Commercial and Industrial	72.4	75.4
Total Customer Usage (GW-hrs)	**153.1**	**164.7**
Gallons Provided		
Wastewater treated (millions of gallons)	464	446
Water sold (millions of gallons)	927	867
Total Gallons Provided	**1,391**	**1,313**

For the three months ended March 31, 2014, the Liberty Utilities (West) region's electricity usage totalled 153.1 GW-hrs, as compared to 164.7 GW-hrs for the same period in 2013, a decrease of 11.6 GW-hrs. Under the base rate revenue decoupling mechanism approved by the CPUC, which became effective on January 1, 2013, the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in the weather conditions and changes in the number of customers. Instead, the CalPeco Electric System is required to record 1/12 of its annual base rate revenue requirement each month. The electricity commodity continues to be passed through to the CalPeco Electric System's customers according to their consumption.

During the three months ended March 31, 2014, the Liberty Utilities (West) region provided approximately 927 million gallons of water to its customers and treated approximately 464 million gallons of wastewater, as compared to 867 gallons of water and 446 gallons of wastewater during the same period in 2013.

	Three months ended March 31,		Three months ended March 31,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Water Assets for regulatory purposes	**178.2**	183.5		
Electricity Assets for regulatory purposes	**177.3**	167.5		
Revenue				
Utility electricity sales and distribution	**$ 19.7**	$ 20.9	**$ 21.7**	$ 21.1
Wastewater treatment	**4.7**	4.6	**5.2**	4.7
Water distribution	**4.0**	3.8	**4.4**	3.8
Other Revenue	**—**	—	**—**	—
	$ 28.4	$ 29.3	**$ 31.3**	$ 29.6
Less:				
Cost of Sales – Electricity	**(10.4)**	(11.5)	**(11.5)**	(11.6)
Net Utility Sales	**$ 18.0**	$ 17.8	**$ 19.8**	$ 18.0
Expenses				
Operating expenses	**(8.6)**	(9.1)	**(9.5)**	(9.2)
Other income	**0.3**	0.6	**0.3**	0.6
Division operating profit	**$ 9.7**	$ 9.3	**$ 10.6**	$ 9.4

2014 First Quarter Operating Results

For the three months ended March 31, 2014, the Liberty Utilities (West) region's revenue totalled U.S. $28.4 million as compared to U.S.$29.3 million during the same period in 2013, a decrease of U.S. $0.9 million or 3.1%.

For the three months ended March 31, 2014, the Liberty Utilities (West) region's revenue from utility electricity sales totalled U.S. $19.7 million as compared to U.S. $20.9 million during the same period in 2013, a decrease of U.S. $1.2 million or 5.7%. This decrease in gross revenues is primarily due to the energy cost adjustment clause ("ECAC"). The ECAC component of gross revenue was $12.8 million in the first quarter of 2014 as compared to $14.0 million in the comparable period in the prior year due to lower customer usage. The ECAC component is not a part of base revenue, and is therefore excluded from the decoupling mechanism adjustment. Under the base rate revenue decoupling mechanism the CalPeco Electric System's base rate revenues will not be impacted by fluctuations in customer demand due to the variations in weather conditions and changes in the number of customers.

For the three months ended March 31, 2014, revenue from wastewater treatment and water distribution totalled U.S. $4.7 million and U.S. $4.0 million, respectively, as compared to U.S. $4.6 million and U.S. $3.8 million, respectively, during the same period in 2013. The total increase in wastewater treatment and water distribution revenue was primarily due to an increase in usage, primarily due to increased connections as compared to the same period in 2013.

For the three months ended March 31, 2014, fuel and purchased power costs for the Liberty Utilities (West) region totalled U.S $10.4 million, as compared with U.S. $11.5 million for the same period in 2013, a decrease of $1.1 million due to lower customer usage. As a result of ECAC, recorded electricity expenses are matched with recorded revenues and the difference is tracked in a balancing account. Overcollections and undercollections for a period are returned to or recovered from ratepayers in the following ratesetting period, usually one year.

The purchase of electricity by the Liberty Utilities (West) region is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the Liberty Utilities (West) region compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended March 31, 2014, net utility sales for the Liberty Utilities (West) region were U.S. $18.0 million, as compared to U.S. $17.8 million during the same period in 2013, an increase of $0.2 million or 1.1%.

For the three months ended March 31, 2014, operating expenses totalled U.S. $8.6 million, as compared to U.S. $9.1 million during the same period in 2013.

For the three months ended March 31, 2014, the Liberty Utilities (West) region's operating profit was U.S. $9.7 million as compared to U.S. $9.3 million in the same period in 2013, an increase of U.S. $0.4 million or 4.3%.

Measured in Canadian dollars, the Liberty Utilities (West) region's operating profit was $10.6 million as compared to $9.4 million in the same period in 2013.

Liberty Utilities: Central Region

	Three months ended March 31,	
	2014	2013
Average Active Natural Gas Connections For The Period		
Residential	71,900	72,900
Commercial and Industrial	9,300	9,400
Total Average Active Natural Gas Connections For The Period	**81,200**	**82,300**
Average Active Water Connections For The Period		
Wastewater connections	5,900	5,900
Water distribution connections	21,600	21,800
Total Average Active Water Connections For The Period	**27,500**	**27,700**
Customer Usage (MMBTU)		
Residential	3,368,000	2,684,000
Commercial and Industrial	1,912,000	1,510,000
Total Customer Usage (MMBTU)	**5,280,000**	**4,194,000**
Gallons Provided		
Wastewater treated (millions of gallons)	82.6	80.0
Water sold (millions of gallons)	780.1	510.0
Total Gallons Provided	**862.7**	**590.0**

The Liberty Utilities (Central) region acquired the Pine Bluff Water System on February 1, 2013. Consequently, there is one additional month of operations from this utility in the first quarter of 2014 as compared to the first quarter of 2013.

For the three months ended March 31, 2014, the Liberty Utilities (Central) region natural gas distribution sales totalled 5,280,000 MMBTU as compared to 4,194,000 during the same period in 2013, an increase of 1,086,000 MMBTU or 25.9%. The increase in volumes can be primarily attributed to the below seasonal temperatures experienced in the first quarter of 2014 as compared to the same period in 2013.

During the three months ended March 31, 2014, the Liberty Utilities (Central) region provided approximately 780.1 million gallons of water to its customers, and treated approximately 82.6 million gallons of wastewater, as compared to 510.0 million gallons of water and 80.0 million gallons of wastewater during the same period in 2013.

		Three months ended March 31,			Three months ended March 31,	
		2014 U.S. $ (millions)		2013 U.S. $ (millions)	**2014 Can $ (millions)**		2013 Can $ (millions)
Natural Gas Assets for regulatory purposes		**150.7**		135.8			
Water Assets for regulatory purposes		**55.1**		51.4			
Revenue							
Utility natural gas sales and distribution	**$**	**37.6**	$	29.8	**$ 41.5**	$	30.1
Wastewater treatment		**1.5**		1.4	**1.7**		1.4
Water distribution		**3.0**		2.2	**3.4**		2.2
Gas Transportation		**1.8**		1.1	**2.0**		1.1
		43.9		34.5	**48.6**		34.8
Less:							
Cost of Sales – Natural Gas[1]		**(27.3)**		(20.7)	**(30.1)**		(20.8)
Net utility sales		**16.6**		13.8	**18.5**		14.0
Expenses							
Operating expenses		**(6.8)**		(6.5)	**(7.5)**		(6.6)
Other income		**0.1**		—	**0.1**		—
Division operating profit	**$**	**9.9**	$	7.3	**$ 11.1**	$	7.4

1 Natural Gas costs are shown net of U.S. $3.7 million of gas deferral debits due to overcollection of gas commodity costs in the quarter.

2014 First Quarter Operating Results

For the three months ended March 31, 2014, the Liberty Utilities (Central) region's revenue totalled U.S. $43.9 million as compared to U.S. $34.5 million during the same period in 2013, an increase of U.S. $9.4 million. The increase in revenue can be primarily attributed to the increased natural gas sales and distribution discussed below.

For the three months ended March 31, 2014, the Liberty Utilities (Central) region's revenue from natural gas sales and distribution totalled U.S. $37.6 million as compared to U.S. $29.8 million during the same period in 2013, an increase of U.S. $7.8 million or 26.2%. The increase in revenue can be primarily attributed to higher customer usage resulting from below seasonal temperatures experienced in the first quarter of 2014 as compared to the same period in 2013.

For the three months ended March 31, 2014, the Liberty Utilities (Central) region's revenue from gas transportation sales totalled U.S. $1.8 million as compared to U.S. $1.1 million during the same period in 2013, an increase of U.S. $0.7 million.

For the three months ended March 31, 2014, revenue from wastewater treatment and water distribution totalled U.S. $1.5 million and $3.0 million, as compared to U.S. $1.4 million and $2.2 million during the same period in 2013. The increase in total wastewater treatment and water distribution revenue can be primarily attributed to the addition of the Pine Bluff Water System on February 1, 2013.

For the three months ended March 31, 2014, natural gas purchases for the Liberty Utilities (Central) region's natural gas utility totalled U.S $27.3 million, as compared with U.S. $20.7 million for the same period in 2013, an increase of $6.6 million. The increase in natural gas cost was primarily driven by the increased cost to purchase natural gas due to below seasonal temperatures experienced in the first quarter of 2014.

The purchase of natural gas by the Liberty Utilities (Central) region 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 sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended March 31, 2014, net utility sales for the Liberty Utilities (Central) region totalled U.S. $16.6 million as compared to U.S. $13.8 million during the same period in 2013, an increase of U.S. $2.8 million, or 20.3%.

For the three months ended March 31, 2014, operating expenses, excluding natural gas purchases, totalled U.S. $6.8 million, as compared to U.S. $6.5 million during the same period in 2013. The increase in operating expenses is primarily attributed to an additional month of operating expenses at the Pine Bluff Water System in the first quarter of 2014 as compared to the same period in 2013, as the utility was acquired on February 1, 2013.

For the three months ended March 31, 2014, the Liberty Utilities (Central) region's operating profit was U.S. $9.9 million as compared to U.S. $7.3 million in the same period in 2013, an increase of U.S. $2.6 million.

Measured in Canadian dollars, the Liberty Utilities (Central) region's operating profit was $11.1 million as compared to $7.4 million in the same period in 2013.

Liberty Utilities: East Region

	Three months ended March 31,	
	2014	**2013**
Average Active Natural Gas Connections For The Period		
Residential	180,200	75,200
Commercial and Industrial	17,100	9,280
Total Average Active Natural Gas Connections For The Period	**197,300**	**84,480**
Average Active Electric Connections For The Period		
Residential	36,200	36,700
Commercial and Industrial	6,600	6,500
Total Average Active Electric Connections For The Period	**42,800**	**43,200**
Customer Usage (GW-hrs)		
Residential	90.2	78.1
Commercial and Industrial	151.2	155.9
Total Customer Usage (GW-hrs)	**241.4**	**234.0**
Customer Usage (MMBTU)		
Residential	6,908,000	2,862,000
Commercial and Industrial	3,959,000	1,248,000
Total Customer Usage (MMBTU)	**10,867,000**	**4,110,000**

For the three months ended March 31, 2014, the Liberty Utilities (East) region's electricity usage totalled 241.4 GW-hrs and natural gas usage totalled 10,867,000 MMBTU as compared to 234.0 GW-hrs and 4,110,000 MMBTU during the same period in 2013. The Peach State Gas System usage totalled 2,999,000 MMBTU, while the New England Gas System usage totalled 2,703,000 MMBTU.

	Three months ended March 31,		Three months ended March 31,	
	2014 U.S. $ (millions)	2013 U.S. $ (millions)	**2014 Can $ (millions)**	2013 Can $ (millions)
Electricity Assets for regulatory purposes	**105.0**	89.3		
Natural Gas for regulatory purposes	**513.2**	263.9		
Revenue				
Utility electricity sales and distribution	**$ 33.0**	$ 21.6	**$ 36.4**	$ 21.8
Utility natural gas sales and distribution[1,2]	**140.4**	53.5	**154.9**	54.1
Gas Transportation	**8.6**	5.0	**9.5**	4.9
Other Revenue	**0.6**	—	**0.7**	—
	$ 182.6	$ 80.1	**$ 201.5**	$ 80.8
Less:				
Cost of Sales – Electricity	**(20.6)**	(14.3)	**(22.7)**	(14.4)
Cost of Sales – Natural Gas[1,2,3]	**(99.2)**	(37.8)	**(109.4)**	(38.2)
Net Utility Sales	**$ 62.8**	$ 28.0	**$ 69.4**	$ 28.2
Expenses				
Operating expenses	**(25.1)**	(13.3)	**(27.6)**	(13.4)
Other income	**0.4**	0.4	**0.4**	0.4
Division operating profit	**$ 38.1**	$ 15.1	**$ 42.2**	$ 15.2

[1] Represents New England Gas System revenue and gas costs since December 20, 2013 acquisition date.

[2] Represents Peach State Gas System revenue and gas costs since April 1, 2013 acquisition date.

[3] Natural Gas costs are shown net of U.S. $18.8 million of gas deferral credits due to undercollection of gas commodity costs in the quarter.

2014 First Quarter Operating Results

For the three months ended March 31, 2014, the Liberty Utilities (East) region's revenue totalled U.S. $182.6 million, as compared to U.S. $80.1 million during the same period in 2013, an increase of U.S. $102.5 million, or 128.0%. The increase in revenue can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013 along with the below seasonal temperatures experienced during the first quarter of 2014 as compared to the first quarter of 2013.

For the three months ended March 31, 2014, the Liberty Utilities (East) region's revenue from utility electricity sales totalled U.S. $33.0 million as compared to U.S. $21.6 million during the same period in 2013, an increase of $11.4 million, or 52.8%, primarily due to increased distribution rates to customers as a result of the implementation of interim rates for the general rate case, increased customer demand, and higher cost of electricity due to below seasonal temperatures experienced during the quarter. In addition, the region recognized additional revenue related to the implementation of the final rate case for Granite State Electric System in the amount of $2.5 million representing the difference between interim rates previously granted and final rates retroactive to July 1, 2013.

For the three months ended March 31, 2014, the Liberty Utilities (East) region's revenue from natural gas sales and distribution totalled U.S. $140.4 million as compared to U.S. $53.5 million during the same period in 2013, an increase of U.S. $86.9 million. During the three months ended March 31, 2014, the EnergyNorth Gas System contributed U.S. $75.6 million, while the Peach State Gas System contributed U.S.$25.4 million, and the newly acquired the New England Gas System contributed U.S. $39.4 million.

For the three months ended March 31, 2014, the Liberty Utilities (East) region's revenue from gas transportation sales totalled U.S. $8.6 million as compared to U.S. $5.0 million during the same period in 2013, an increase of U.S. $3.6 million. During the three months ended March 31, 2014, the EnergyNorth Gas System contributed U.S.$4.1 million, the Peach State Gas System contributed U.S. $0.5 million, and the newly acquired New England Gas System contributed U.S. $4.0 million.

For the three months ended March 31, 2014, electricity purchases for the Liberty Utilities (East) region totalled U.S. $20.6 million, and natural gas purchases totalled U.S. $99.2 million as compared to U.S. $14.3 million and U.S. $37.8 million, respectively, during the same period in 2013. The overall electricity purchase expense increase of U.S $6.3 million was primarily the result of an 39% increase in weighted average electricity rates as compared to the same period in 2013 and a 3% increase in the volume of electricity purchased to meet customer demand. The overall natural gas purchases increase can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013, and the below seasonal temperatures experienced during the first quarter of 2014 as compared to the first quarter of 2013.

The cost of electricity and natural gas is passed through to the Liberty Utilities (East) region's customers. As a result, the division compares 'net utility sales' (see non-GAAP Financial Measures) as a more appropriate measure of the division's results. For the three months ended March 31, 2014, net utility sales for the Liberty Utilities (East) region totalled U.S. $62.8 million as compared to U.S. $28.0 million during the same period in 2013, an increase of U.S.$34.8 million primarily due to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013, below seasonal temperatures experienced during the first quarter of 2014 as compared to the first quarter of 2013, an interim annual rate increase approved by the NHPUC on June 27, 2013 at the Granite State Electric System, and the true up to the final rates upon finalization of the rate case on March 17, 2014.

For the three months ended March 31, 2014, operating expenses, excluding electricity and natural gas purchases, totalled U.S. $25.1 million as compared to U.S. $13.3 million during the same period in 2013, an increase of U.S. $11.8 million. The increase in operating expenses as compared to the same period in 2013 can be primarily attributed to the acquisition of the Peach State Gas System on April 1, 2013 and the New England Gas System on December 20, 2013.

For the three months ended March 31, 2014, other income for the Liberty Utilities (East) region totaled U.S. $0.4 million, and primarily consists of an equity allowance for funds utilized during construction and rental income.

For the three months ended March 31, 2014, the Liberty Utilities (East) region's operating profit totalled U.S. $38.1 million as compared to U.S. $15.1 million during the same period in 2013, an increase of U.S. $23.0 million.

Measured in Canadian dollars, the Liberty Utilities (East) region's operating profit was $42.2 million as compared to $15.2 million during the same period in 2013, an increase of $27 million.

Regulatory Proceedings

The following table summarizes the major regulatory proceedings within Liberty Utilities currently underway:

Utility	State	Regulatory Proceeding Type	Rate Request	Current Status
LPSCo Water System	Arizona	General Rate Case	U.S. $3.0 million	Preliminary order was issued on March 2014. Final Order approving U.S. $1.8 million increase was received in April 2014.
Peach State Gas System	Georgia	Georgia Rate Adjustment Mechanism ("GRAM") filing	U.S. $4.9 million	In Q1 Georgia Public Service Commission agreed to a settlement providing an annual revenue increase of U.S. $4.7 million. Final Commission approval expected in Q2 2014.
Granite State Electric System	New Hampshire	General Rate Case	U.S. $13.0 million + U.S. $1.2 million step adjustment in 2014	Commission approval received in Q1 2014 for U.S. $9.8 million + U.S. $1.1 million step increase for 2014.
Missouri Gas System	Missouri	General Rate Case	U.S. $6.0 million	Order expected in Q1 2015.
Illinois Gas System	Illinois	General Rate Case	U.S. $5.7 million	Order expected in Q1 2015.

In the first quarter of 2013, the Granite State Electric System filed a rate case with the NHPUC seeking an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. On March 17, 2014, the commission approved a settlement of U.S. $9.8 million and $1.1 million step increase for 2014. The difference between the sought and received amounts in the Granite State Electric System General Rate Case related largely due to differences in rates of return and changes in the amortization rates related to pension balances and fixed assets on a go forward basis.

In the first quarter of 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") seeking an increase in EBITDA of U.S. $6.0 million. The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate base adjusted to reflect known and measurable changes through April 30, 2014. The case is expected to conclude in the first quarter of 2015.

In the first quarter of 2014, the Midstates Gas System filed a rate case with the Illinois Public Service Commission ("IPSC") seeking an increase in EBITDA of U.S. $5.7 million. The filing is based on a test year that includes anticipated capital expenditures within 2014 and 2015. The case is expected to conclude in the first quarter of 2015.

Corporate and Other Expenses

	Three months ended March 31,	
	2014 (millions)	2013 (millions)
Corporate and other expenses:		
Administrative expenses[1]	**$ 7.7**	$ 4.9
(Gain)/Loss on foreign exchange	**(1.8)**	(0.5)
Interest expense	**16.2**	12.2
Interest, dividend and other Income	**(1.2)**	(0.5)
Acquisition-related costs	**0.3**	0.5
(Gain)/Loss on derivative financial instruments	**(0.4)**	(1.4)
Income tax expense/(recovery)	**11.9**	6.3

[1] Administrative expenses relates to costs for APUC, APCO, and Liberty Utilities.

2014 FIRST QUARTER CORPORATE AND OTHER EXPENSES

During the quarter ended March 31, 2014, administrative expenses totalled $7.7 million, as compared to $4.9 million in the same period in 2013. The expense increase for the quarter is primarily due to additional personnel, increased wages, and additional cost required to administer APUC's operations compared to the same period in 2013 as a result of the continued growth of the company. In addition, approximately $2.0 million of expenses previously classified as direct operating expenses have been reclassified in 2014 as administrative expenses as certain functions are now being performed centrally as part of a shared services function across the entire company.

For the quarter ended March 31, 2014, interest expense totalled $16.2 million as compared to $12.2 million in the same period in 2013. The increased interest expense is a result of new indebtedness incurred in the latter part of 2013 and first quarter of 2014 used to finance the new acquisitions and other growth initiatives.

For the quarter ended March 31, 2014, interest, dividend and other income totalled $1.2 million, as compared to $0.5 million in the same period in 2013. Interest, dividend and other income primarily consists of dividends from APUC’s share investment in the Kirkland and Cochrane facilities.

For the quarter ended March 31, 2014, gains on derivative financial instruments totalled $0.4 million, as compared to $1.4 million in the same period in 2013. The increase was primarily driven by derivative gains on hedges to purchase electricity for resale at contracted rates more favorable than the market rate.

An income tax expense of $11.9 million was recorded in the three months ended March 31, 2014, as compared to an expense of $6.3 million during the same period in 2013. The income tax expense for the three months ended March 31, 2014 primarily increased due to higher earnings in the U.S. operations, deferred taxes on HLBV income, 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, and other items permanently non-deductible for tax purposes.

NON-GAAP PERFORMANCE MEASURES

Reconciliation of Adjusted EBITDA to net earnings

The following table is derived from and should be read in conjunction with the audited 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 March 31,	
	2014 (millions)	2013 (millions)
Net earnings attributable to Shareholders	**$ 35.9**	$ 19.2
Add (deduct):		
Net earnings / (loss) attributable to the non-controlling interest, exclusive of HLBV	**3.8**	3.1
(Earnings) / loss from discontinued operations	**(0.3)**	1.1
Income tax expense / (recovery)	**11.9**	6.3
Interest expense	**16.2**	12.2
Gain on sale of assets	**(0.3)**	—
Write down on note receivable	**0.7**	—
Acquisition costs	**0.3**	0.5
(Gain)/Loss on derivative financial instruments	**(0.4)**	(1.4)
Realized Gain (Loss) on Energy Derivative Contracts	**3.5**	0.3
(Gain)/Loss on foreign exchange	**(1.8)**	(0.5)
Depreciation and amortization	**28.0**	22.0
Adjusted EBITDA	**$ 97.5**	$ 62.8

Hypothetical Liquidation at Book Value ("HLBV") represents the value of net tax attributes earned by APCo in the period from electricity generated by certain of its U.S. wind power generation facilities. The value of net tax attributes earned in the three months ended March 31, 2014 and March 31, 2013 amounted to approximately $8.5 million and $5.0 million, respectively.

For the quarter ended March 31, 2014, Adjusted EBITDA totalled $97.5 million as compared to $62.8 million, an increase of $34.7 million compared to the same period in 2013. 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 March 31 (millions)
Comparative Prior Period Adjusted EBITDA	$	62.8
Significant Changes:		
Liberty Utilities:		
Increased delivery and treatment of water and wastewater at the Liberty Utilities (West) region		0.7
2013 Acquisitions of natural gas systems		17.4
Increased demand at the Midstates and EnergyNorth Gas Systems, in addition to increased rates as a result of the Granite State rate case settlement.		7.4
APCo:		
Renewable		
Decreased hydrology resource		(1.1)
Increased wind resources at the U.S. Wind Facilities offset by unfavorable periodic hedge settlements shortfalls at the Minonk, Sandy Ridge and Senate facilities		0.3
Sale of Renewable Energy Credits		1.6
Increased wind resources at the St Leon wind facilities		1.7
Increased demand for retail sales at AES offset by increased energy prices		(0.2)
Thermal		
Windsor Locks & Sanger Facilities - Increased energy sales		1.0
Administrative expense		(2.9)
Increased results from the stronger U.S. dollar		6.7
Other		2.1
Current Period Adjusted EBITDA	$	97.5

Reconciliation of adjusted net earnings to net earnings

The following table is derived from and should be read in conjunction with the audited 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 March 31,			
		2014 (millions)		2013 (millions)
Net earnings attributable to Shareholders	**$**	**35.9**	$	19.2
Add (deduct):				
(Gain) / Loss from discontinued operations, net of tax		**(0.3)**		1.1
(Gain)/Loss on derivative financial instruments, net of tax		**(0.2)**		(0.8)
Realized Gain/(Loss) on derivative instruments, net of tax		**2.0**		0.1
(Gain)/Loss on foreign exchange, net of tax		**(1.1)**		(0.3)
Write down on note receivable, net of tax		**0.5**		—
Gain on asset disposal, net of tax		**(0.2)**		—
Acquisition costs, net of tax		**0.2**		0.3
Adjusted net earnings	**$**	**36.8**	$	19.6
Adjusted net earnings per share	**$**	**0.17**	$	0.09

For the three months ended March 31, 2014, adjusted net earnings totalled $36.8 million as compared to adjusted net earnings of $19.6 million, an increase of $17.2 million as compared to the same period in 2013. The increase in adjusted net earnings for the three months ended March 31, 2014 is primarily due to increased earnings from operations partially offset by higher depreciation and amortization expense, and higher interest expense as compared to the same period in 2013.

Reconciliation of adjusted funds from operations to cash flows from operating activities

The following table is derived from and should be read in conjunction with the audited 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 March 31,			
		2014 (millions)		2013 (millions)
Cash flows from operating activities	**$**	**14.8**	$	(4.7)
Add (deduct):				
Changes in non-cash operating items		**58.4**		51.9
Cash (provided)/used in discontinued operation		**0.2**		(0.1)
Production Tax Credits received from non-controlling interests		**9.0**		—
Cross Currency Swap interest difference		**—**		0.1
Acquisition costs		**0.3**		0.5
Adjusted funds from operations	**$**	**82.7**	$	47.7
Adjusted funds from operations per share		**0.39**		**0.23**

For the three months ended March 31, 2014, adjusted funds from operations totalled $82.7 million as compared to adjusted funds from operations of $47.7 million,an increase of $35.0 million as compared to the same period in 2013.

SUMMARY OF PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

	Three months ended March 31,	
	2014 (millions)	2013 (millions)
APCo:		
Renewable	**$ 11.2**	$ 4.1
Thermal	**1.4**	0.2
Total APCo	**$ 12.6**	$ 4.3
LIBERTY UTILITIES		
West	**1.8**	1.4
Central	**5.6**	7.1
East	**12.2**	3.6
Total Liberty Utilities	**$ 19.6**	$ 12.1
Corporate	**44.7**	0.1
Total	**$ 76.9**	$ 16.5

The company's consolidated capital expenditure plan for 2014 is approximately $505.0 million. APCo expects to invest approximately $247.3 million throughout the remainder of the fiscal year primarily in connection with the development of its existing project pipeline. Liberty Utilities expects to invest approximately $180.5 million throughout the remainder of the fiscal year primarily to improve the reliability and efficiency of its gas, and electric utility distribution systems.

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

2014 First Quarter Property Plant and Equipment Expenditures

During the three months ended March 31, 2014, APCo incurred capital expenditures of $12.6 million, as compared to $4.3 million during the comparable period in 2013. During the three months ended March 31, 2014, APCo's Renewable Energy Division spent $11.2 million in capital expenditures as compared to $4.1 million in the comparable period in 2013. The increase is primarily due to turbine contract payments related to the Morse Wind Project, completion of construction of the Cornwall Solar Project, and costs related to the St. Damase Wind and the Bakersfield Solar Projects. APCo's Thermal Energy Division net capital expenditures were $1.4 million, as compared to $0.2 million in the comparable period in 2013. The Thermal Division's capital expenditures consist of $0.3 million relating to Windsor Locks Thermal Facility and $1.1 million relating to a turbine overhaul at the Sanger Thermal Facility.

During the three months ended March 31, 2014, Liberty Utilities invested $19.6 million in capital expenditures as compared to $12.1 million during the comparable period in 2013. The Liberty Utilities (West) region's capital expenditures primarily related to improvement and replenishment at the CalPeco Electric System. The Liberty Utility (Central) region's $5.6 million in capital expenditures was primarily related to pipe expansion and replacement activities. The Liberty Utility (East) region's $12.2 million in capital expenditures was primarily related to a second supply line and reliability enhancement projects on the Granite State Electric System, the implementation of a new IT system at the Granite State Electric and EnergyNorth Gas Systems, and growth and system upgrades at the Peach State Gas System.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C93), APCo has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. Out of these, nine assessments have been submitted to and accepted by the Quebec government. The assessments have identified possible remedial work at seven facilities. Of these seven, remediation work has now been completed at three facilities, monitoring activities and options analysis are being performed for two facilities, and remedial work is being planned at two facilities.

APCo currently estimates further capital expenditures of approximately $15.1 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	2014	2015	2016	2017
Future Estimated Bill C-93 Capital Expenditures	15.1	0.5	7.5	6.8	0.3

The majority of these capital costs are associated with the Donnacona, St. Alban, Belleterre, and Rivière-du-Loup Hydro Facilities.

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 APUC, APCo and Liberty Utilities to manage the liquidity and working capital requirements of each division (collectively the "Facilities").

Bank Credit Facilities

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at March 31, 2014 under the Facilities:

	As at March 31, 2014				As at Dec 31 2013
	APUC (millions)	APCo (millions)	Liberty Utilities (millions)	Total (millions)	Total (millions)
Committed Facilities	$ 65.0	$ 200.0	$ 221.1	$ 486.1	$ 477.7
Funds drawn on Facilities	—	(105.1)	(75.4)	(180.5)	(210.2)
Letters of Credit issued	(10.3)	(57.5)	(7.5)	(75.3)	(64.9)
Funds available for draws on the Facilities	**$ 54.7**	**$ 37.4**	**$ 138.2**	**$ 230.3**	**$ 202.6**
Cash on Hand				31.7	13.8
Total liquidity and capital reserves	**$ 54.7**	**$ 37.4**	**$ 138.2**	**$ 262.0**	**$ 216.5**

As at March 31, 2014, the APUC Credit Facility, had $65.0 million senior unsecured revolving credit facility, was undrawn and had $10.3 million of outstanding letters of credit.

As at March 31, 2014, the APCo $200.0 million senior unsecured revolving credit facility (the "APCo Facility") had drawn $105.1 million and had $57.5 million in outstanding letters of credit under the APCo Facility.

As at March 31, 2014, the Liberty Utilities $221.1 million (U.S.$200.0 million) senior unsecured revolving credit facility (the "Liberty Facility") had drawn $75.4 million and had $7.5 million of outstanding letters of credit.

Long Term Debt

On January 17, 2014, APCo issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "APCo Debentures") pursuant to a private placement in Canada and the United States. The APCo Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, APCo entered into a fixed for fixed cross currency swap, coterminous with the APCo Debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

As at March 31, 2014, the weighted average tenor of APUC's total long term debt is approximately 7.4 years with an average interest rate of 4.8%.

Contractual Obligations

Information concerning contractual obligations as of March 31, 2014 is shown below:

		Total (millions)		Due less than 1 year (millions)		Due 1 to 3 years (millions)		Due 4 to 5 years (millions)		Due after 5 years (millions)
Long-term debt obligations	$	1,409.4		8.6		128.6		163.0		1,109.2
Advances in aid of construction	$	82.2		1.3		—		—		80.9
Interest on long-term debt obligations	$	487.9		65.8		124.7		109.8		187.6
Purchase obligations	$	161.9		161.9		—		—		—
Environmental Obligations	$	76.4		21.7		42.6		2.3		9.8
Derivative financial instruments:										
Cross Currency Swap	$	17.7		0.7		—		—		17.0
Interest rate swap	$	2.8		1.9		0.9		—		—
Energy derivative contracts	$	9.5		1.3		—		—		8.2
Capital lease obligations	$	4.2		0.1		4.1		—		—
Capital projects	$	27.9		27.9		—		—		—
Long term service agreements	$	632.7		24.0		56.5		58.4		493.8
Purchased power	$	110.8		76.7		34.1		—		—
Gas delivery, service and supply agreements	$	154.1		57.1		56.5		25.5		15.0
Operating leases	$	110.1		5.7		9.0		7.3		88.1
Other obligations	$	22.5		7.9		—		—		14.6
Total obligations	**$**	**3,310.1**	**$**	**462.6**	**$**	**457.0**	**$**	**366.3**	**$**	**2,024.2**

Equity

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at March 31, 2014, APUC had 206,867,070 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 March 31, 2014, APUC had outstanding:

- 4,800,000 cumulative rate reset preferred shares, Series A (the "Series A Shares"), yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares (the "Series C Shares") that were issued in exchange for 100 Class B limited partnership units issued by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset preferred shares, Series D (the "Series D Shares"), yielding 5.0% annually for the initial five-year period ending on March 31, 2019

APUC has a shareholder dividend reinvestment plan (the "Reinvestment Plan") for registered shareholders of APUC. As at March 31, 2014 there were 49.8 million common shares representing approximately 24% of total shares outstanding that had been registered with the Reinvestment Plan. During the quarter ended March 31, 2014 there were 501,818 common shares issued under the Reinvestment Plan, and subsequent to the end of the quarter, on April 15, 2014, there were 581,606 common shares issued under the Reinvestment Plan.

Emera ownership

As at May 8, 2014, in total, Emera owns 50.1 million APUC common shares representing approximately 24.2% of the total outstanding common shares of the Company, and there are no subscription receipts allowing for further issuances of common shares currently held by Emera. 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 months ended March 31, 2014, APUC recorded $420 (2013 - $424) 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 March 31, 2014, total unrecognized compensation costs related to non-vested options and share unit awards were $1.4 million and $0.1 million respectively, and are expected to be recognized over a period of 1.36 years and 0.75 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. Except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

As at March 31, 2014, APUC had 4,567,129 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

APUC issues 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.

As at March 31, 2014, a total of 65,904 PSU's have been granted and outstanding under the PSU plan.

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 March 31, 2014, a total of 83,073 DSUs had been granted under the DSU plan.

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 March 31, 2014, a total of 163,080 shares had been issued under the ESPP.

RELATED PARTY TRANSACTIONS

A member of the Board of Directors of APUC is an executive at Emera Inc. ("Emera"). For the three months ended March 31, 2014, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,515 (2013 - U.S. $1,635). For the three months ended March 31, 2014, Liberty Utilities purchased natural gas amounting to U.S. $2,977 (2013 - $1,331) from Emera for its gas utility customers. There were no amounts outstanding related to these transactions at the end of the periods. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction.

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

Ian Robertson and Chris Jarratt ("Senior Executives"), respectively Chief Executive Officer and Vice-Chair of APUC partially own an entity from which APUC leases its head office facilities. Base lease costs for the three months ended March 31, 2014 were $79 (2013 - $84). The current office lease for a portion of its head office facilities expires on December 31, 2015. On January 3, 2014, APUC, through a wholly owned subsidiary, acquired from a third party a new office facility. Occupancy is expected to occur in the third quarter of 2014 at which time the currently occupied premises will be subleased to third parties.

TREASURY RISK MANAGEMENT

APUC attempts to proactively manage the risk exposures of its subsidiaries in a prudent manner. There are a number of monetary and financial risk factors relating to the business of APUC and its subsidiaries. The risks discussed below are not intended as a complete list of all exposures that APUC may encounter. Reference should be made to APUC's most recent annual MD&A and its most recent AIF.

Market price risk

Liberty Utilities is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

APCo has certain market price risk exposures and takes steps to mitigate those risks.

On May 15, 2012, APCo entered into a financial hedge, which expires December 31, 2016 with respect to its Dickson Dam Hydro 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 Wind Facility included a financial hedge which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's production volume against exposure to PJM Western Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $0.3 million for the year.

The December 10, 2012 acquisition of Senate Wind Facility included a physical hedge which commenced on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge 64% of Senate Wind Facility's production volume against exposure to ERCOT North Zone current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in the market prices would result in a change in revenue of about $1.1 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's production volume against exposure to PJM Northern Illinois Hub current spot market rates. For the unhedged portion of production, each $10 per MW-hr change in market prices would result in a change in revenue of about $1.1 million for the year.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure cannot be quantified as it is dependent on both the amount of shortfall, and the market price of electricity at the time of the shortfall. APCo mitigates this risk exposure by entering into hedge quantities for less than 100% of the long term average expected production thereby reducing the risk of not producing the minimum hedge quantities.

APCo entered into unit contingent financial hedges which commenced January 1, 2014 for a one year period. These hedges are structured to hedge all of the production from the Facilities in excess of the production covered by the hedges described in the three preceding paragraphs. The hedges do not have a minimum volume commitment and hence the facilities do not bear any market risk associated with production. As a result, the Sandy Ridge, Senate and Minonk Wind Facilities now have hedges in place covering 100% of the energy produced.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract which commenced on January 1, 2013 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each $10 per MW-hr change in market prices would result in a change in revenue of about $0.5 million for the year.

Interest rate risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

- The APUC Facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at March 31, 2014. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The APCo Facility had $105.1 million outstanding as at March 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $1.1 million annually.

- APCo's project debt at its Sanger Thermal Facility has a balance of U.S. $19.2 million as at March 31, 2014. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.
- The Shady Oaks Senior Debt Facility had $82.0 million outstanding as at March 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.82 million annually.
- The Liberty Facility had $75.4 million outstanding as at March 31, 2014. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.7 million annually.

APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

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.

Both APCo and Liberty have established financing platforms to access new liquidity from the capital markets as requirements arise. APUC continually monitors the maturity profile of its debt and adjusts accordingly to ensure sufficient liquidity exists at each of APCo and Liberty Utilities to meet their liabilities when due.

As at March 31, 2014, APUC and its subsidiaries had a combined $230.3 million of committed and available credit facilities remaining and $31.7 million of cash resulting in $262.0 million of total liquidity and capital reserves.

APUC currently pays a dividend of $0.34 per common 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, ensures APUC's long-term success.

The long term portion of debt totals approximately $1,409.4 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 favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

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

Commodity price risk

APCO's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Utilities is exposed to energy price risk in its Liberty Utilities (West) and Liberty Utilities (East) regions. Additionally, Liberty Utilities is exposed to natural gas price risk in its Liberty Utilities (Central) and Liberty Utilities (East) regions. See APUC's audited consolidated financial statements for the years ended December 31, 2013 and 2012 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 further assessment of APUC's business risks is set out in the most recent AIF.

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.

Trafalgar proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against APUC, and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to APUC and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "Trafalgar Hydro Facilities"). In 2001, Trafalgar and other entities also filed for Chapter 11 reorganization in bankruptcy court and also filed a multi-count adversary complaint against certain subsidiary entities of APUC, which complaint was then transferred to the District Court. In 2006, the District Court decided that Aetna had complied with the provisions concerning the sale of the Trafalgar Class B Note, that APUC was therefore the holder and owner of the Trafalgar Class B Note, and that all other claims by Trafalgar with respect to the transfer of the Trafalgar Class B Note were without merit. Further, on November 6, 2008, the claims that were remaining in the District Court against APUC were dismissed by summary judgment. On October 22, 2009, Trafalgar filed an appeal from the November 6, 2008 summary judgment to the United States Court of Appeals for the Second Circuit. The Second Circuit Court of Appeals, among other things, on November 2, 2010 dismissed the claims against APUC in the civil proceedings. 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 APUC does not have a security interest in the monies transferred by Trafalgar before it filed for bankruptcy protection.

With respect to the civil proceedings, the United States Second Circuit Court of Appeals dismissed all the claims against APUC 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 filed a notice of appeal of the Memorandum-Decision and Order. The appeal was argued on March 21, 2013. On March 25, 2013, the United States Second Circuit Court of Appeals affirmed the decision of the District Court giving APUC judgment on its claims. Trafalgar asked the United States Second Circuit Court of Appeals for reconsideration of its decision or to certify a legal question to the Connecticut Supreme Court. On May 21, 2013, the United States Second Circuit Court of Appeals denied Trafalgar's petition and the matter was sent back to the District Court for further proceedings with respect to the enforcement of APUC's remedies under the loan documents, including the calculation of the debt and the disposition of collateral. The District Court entered judgment in favor of APUC with regard to the default and APUC's entitlement to recourse to the collateral, but without determining the amount due under the note. The District Court then closed the case.

With respect to the bankruptcy proceedings, on January 30, 2013, the United States Second Circuit Court of Appeals held that Algonquin did have a security interest in Trafalgar's engineering malpractice claim and its proceeds. On February 20, 2013, Trafalgar filed a petition for a rehearing with the United States Second Circuit Court of Appeals, and in the alternative, sought to have the Second Circuit certify a legal question to the New York State Court of Appeals. The Second Circuit denied the petition and certification request which petition was denied on June 17, 2013. On September 16, 2013, Trafalgar filed a Petition for a Writ of Certiorari with the United States Supreme Court. Algonquin filed a brief in opposition to the Petition on October 18, 2013. On December 2, 2013, the United States Supreme Court denied Trafalgar's petition for a Writ of Certiorari. Algonquin filed and served a motion seeking an order terminating the automatic stay and directing the distribution of the funds held in the escrow account to Algonquin. Algonquin's motion for relief from the automatic stay has been denied without prejudice to re-filing the motion after the court determines the amount of Algonquin's claim and the validity of any defenses to the claim. Algonquin and Trafalgar have each filed motions with the Court seeking a determination of those issues. Those motions are under consideration by the Court. On April 21, 2014, Algonquin filed a motion to appoint a trustee pursuant to 11 U.S.C. S 1104(a).

Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec (the "Québec AG") filed suit in Québec Superior Court against Algonquin Dévelopment (Côte Ste-Catherine) Inc. (Dévelopment Hydromega), a predecessor company to an a subsidiary entity of APUC. The Québec AG at trial claimed $5.4 million for amounts that Algonquin Dévelopment Côte Ste-Catherine Inc. had been paying to Seaway Management under the water lease relating to the Côte Ste-Catherine hydroelectric generating facility. Algonquin Dévelopment (Côte Ste-Catherine) Inc. brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011.

On October 21, 2011 the Québec Court of Appeal ordered Algonquin Dévelopment (Côte Ste-Catherine) Inc. to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that Algonquin Dévelopment (Côte Ste-Catherine) Inc. has been paying to the Seaway Management under the water lease 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 $6.0 million. The parties are attempting to resolve this matter through good faith negotiations.

Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corporation, Algonquin Power (Long Sault) Partnership, and N-R Power Partnership ("Long Sault") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global Adjustment ("GA") as a price escalator. As a result of the OEFC's application of the new GA calculation to the calculation of total market cost of electricity ("TMC") of and, in turn, an index derived from TMC, the rate OEFC has paid to Long Sault under the PPA beginning with the application of OEFC's new TMC calculation in July 2011 has not escalated as contemplated in the PPA and term sheet. A Notice of Application was issued at the end of December 2012 with supporting materials filed at the end of April 2013. Cross examinations were held in November, 2013. A hearing is scheduled for early 2014.

Dimos and Katsekas breach of contract claim

On September 30, 2013, previous owners of the Clement Dam hydro facility, filed a demand for arbitration with Algonquin Power Fund (America) Inc. alleging breach of the Purchase Agreement and Royalty Agreement. The claim is for $1,345,257 for alleged breach of such agreements and $155,821 for alleged unpaid royalties. The plaintiffs have demanded arbitration pursuant to such agreements. An arbitration hearing date is scheduled for March, 2015.

Synergics Energy Services, LLC, breach of contract claim

On September 4, 2013, the plaintiff, previous owners of the Great Falls hydro facility, filed a complaint for alleged breach of the 2000 purchase and sale agreement and failure to pay a transfer payment thereunder in the event of the sale of the hydro facility. The claim is for $3,000,000 for alleged breach of the 2000 purchase and sale agreement. Discovery is being scheduled.

Conex Energy-Canada, LLC and Conex Energy, Inc. breach of contract claim

On October 31, 2013, the plaintiffs filed a complaint for, among other things, alleged breach of a confidential agreement in relation to the development and construction of the 10-megawatt solar photovoltaic Cornwall Solar project in Ontario, Canada. APCo has brought a motion to dismiss the compliant.

Bryson School District in Texas property taxes claim

On February 10, 2014, APCo received correspondence from the Bryson School District in Texas regarding Senate Wind LLC's property taxes claiming the Senate Wind Facility owes an additional $2.2 million of property taxes based on an indemnity in the 2010 agreement with the school district. The assertion is being disputed.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarter ended March 31, 2014:

Millions of dollars (except per share amounts)	2nd Quarter 2013	3rd Quarter 2013	4th Quarter 2013	1st Quarter 2014
Revenue	$ 148.8	$ 127.9	$ 205.3	$ 343.5
Adjusted EBITDA	56.5	40.5	67.6	97.5
Net earnings / (loss) attributable to shareholders from continuing operations	15.8	6.3	19.8	35.6
Net earnings / (loss) attributable to shareholders	(18.1)	6.0	13.1	35.9
Net earnings / (loss) per share from continuing operations	0.08	0.02	0.09	0.16
Net earnings / (loss) per share	(0.09)	0.02	0.06	0.17
Adjusted net earnings	15.4	6.9	18.5	36.8
Adjust net earnings per share	0.08	0.03	0.08	0.17
Total Assets	3,201.8	3,156.4	3,472.6	3,652.7
Long term debt[1]	1,091.5	1,092.0	1,255.6	1,409.4
Dividend declared per common share	0.09	0.09	0.09	0.09
	2nd Quarter 2012	**3rd Quarter 2012**	**4th Quarter 2012**	**1st Quarter 2013**
Revenue	$ 58.7	$ 93.0	$ 138.9	$ 193.1
Adjusted EBITDA	22.2	20.8	24.0	61.8
Net earnings / (loss) attributable to shareholders from continuing operations	5.3	(0.6)	6.8	20.4
Net earnings/(loss) attributable to shareholders	6.1	(0.2)	6.4	19.2
Net earnings / (loss) per share from continuing operations	0.03	—	0.04	0.10
Net earnings/(loss) per share	0.04	—	0.03	0.10
Adjusted net earnings	6.5	1.1	6.5	19.4
Adjust net earnings per share	0.04	0.01	0.03	0.10
Total Assets	1,416.0	1,967.1	2,779.0	2,990.7
Long term debt[1]	461.8	705.1	770.8	917.5
Dividend declared per common share	0.07	0.08	0.08	0.08

[1] 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. In addition the company has completed a series of growth initiatives through various acquisitions in both the APCo and Liberty Utilities businesses that have positively impacted growth of APUC.

Quarterly revenues have fluctuated between $58.7 million and $343.5 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 relative to the U.S. 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 $35.9 million and a net loss of 18.1 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.

DISCLOSURE CONTROLS

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 (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

During the quarter ended March 31, 2014, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. APUC continues to implement its internal control structure over the operations of the acquired businesses discussed above.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

APUC prepared its unaudited interim financial statements in accordance with U.S. GAAP. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, related amounts of revenues and expenses, and disclosure of contingent assets and liabilities. Significant areas 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, pension and post-employment benefits, fair value of derivatives and fair value of assets and liabilities acquired in a business combination. Actual results may differ from these estimates.

Management believes there has been no material changes during the three months ended March 31, 2014 to the items discussed in APUC's MD&A and Note 1 of its consolidated financial statements for the year ended December 31, 2013 available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	March 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 31,734	$ 13,839
Accounts receivable, net (note 4)	204,940	160,636
Natural gas in storage	6,439	25,609
Supplies and consumables inventory	8,696	7,924
Regulatory assets (note 5)	61,533	34,643
Prepaid expenses	11,334	11,341
Notes receivable (note 6)	614	598
Deferred tax asset	5,570	19,652
Income tax receivable	390	379
Derivative instruments (note 20)	4,784	9,176
Assets held for sale (note 12)	24,575	23,927
	360,609	307,724
Property, plant and equipment	2,861,378	2,708,704
Intangible assets	55,611	54,416
Goodwill	87,982	84,647
Regulatory assets (note 5)	155,047	155,705
Derivative instruments (note 20)	18,210	27,123
Long-term investments and notes receivable (note 6)	31,914	32,746
Deferred non-current income tax asset (note 3(a))	61,742	86,632
Other assets	20,200	18,784
	$ 3,652,693	$ 3,476,481

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	March 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 13,661	$ 14,489
Accrued liabilities	148,272	146,338
Dividends payable	17,935	17,535
Regulatory liabilities (note 5)	22,792	21,632
Long-term liabilities (note 7)	8,647	8,339
Pension and other post-employment benefits	338	305
Other long-term liabilities	7,994	7,451
Advances in aid of construction	1,287	1,239
Derivative instruments (note 20)	3,937	2,492
Environmental obligations (note 18(a)(ii))	14,116	10,111
Preferred shares series C	1,109	1,038
Liabilities held for sale (note 12)	1,774	1,471
Income tax liability	6,267	5,159
Deferred credits	7,778	7,778
Deferred income tax liability	336	2,308
	256,243	247,685
Long-term liabilities (note 7)	1,400,709	1,247,249
Advances in aid of construction	80,886	77,697
Regulatory liabilities (note 5)	98,801	101,657
Deferred income tax liability	143,835	137,153
Derivative instruments (note 20)	26,138	13,729
Deferred credits	13,738	17,115
Pension and other post-employment benefits	73,580	70,532
Environmental obligation (note 18(a)(ii))	58,938	59,444
Other long-term liabilities	21,380	20,492
Preferred shares Series C	17,722	17,767
	1,935,727	1,762,835
Equity:		
Preferred shares (note 9(b))	213,997	116,546
Common shares (note 9(a))	1,355,088	1,351,264
Additional paid-in capital (note 3(a))	30,067	7,313
Deficit	(471,840)	(488,406)
Accumulated other comprehensive income/(loss) (note 10)	13,002	(31,410)
Total Equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,140,314	955,307
Non-controlling interests (note 3(a))	320,409	510,654
Total Equity	1,460,723	1,465,961
Commitments and contingencies (note 18)		
Subsequent events (notes 9 and 12)		
	$ 3,652,693	$ 3,476,481

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)	Three months ended March 31, 2014	2013
Revenue		
Regulated electricity sales and distribution	$ 58,164	$ 42,855
Regulated gas sales and distributions	207,863	90,089
Regulated water reclamation and distribution	14,641	12,066
Non-regulated energy sales	58,400	46,929
Other revenue	4,449	1,381
	343,517	193,320
Expenses		
Operating	68,997	43,045
Regulated electricity purchased	34,180	26,003
Regulated gas purchased	139,467	59,050
Non-regulated fuel for generation	9,836	5,024
Depreciation of property, plant and equipment	26,895	20,953
Amortization of intangible assets	1,079	1,039
Administrative expenses	7,727	4,860
Gain on foreign exchange	(1,756)	(484)
	286,425	159,490
Operating income from continuing operations	57,092	33,830
Interest expense	16,199	12,199
Interest, dividend income and other income	(2,194)	(2,219)
Gain on asset disposal	(322)	—
Write down on note receivable	698	—
Acquisition-related costs	273	493
Gain on derivative financial instruments (note 20(b)(iv))	(363)	(1,386)
	14,291	9,087
Earnings from continuing operations before income taxes	42,801	24,743
Income tax expense (note 15)		
Current	1,143	190
Deferred	10,727	6,158
	11,870	6,348
Earnings from continuing operations	30,931	18,395
Income/(loss) from discontinued operations net of tax (note 12)	273	(1,149)
Net earnings	31,204	17,246
Net loss attributable to non-controlling interests	(4,648)	(1,964)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 35,852	$ 19,210
Basic net earnings per share from continuing operations (note 16)	$ 0.16	$ 0.09
Basic net earnings/(loss) per share from discontinued operations (note 16)	—	(0.01)
Basic net earnings per share (note 16)	0.17	0.09
Diluted net earnings per share from continuing operations (note 16)	0.16	0.09
Diluted net earnings/(loss) per share from discontinued operations (note 16)	—	(0.01)
Diluted net earnings per share (note 16)	$ 0.16	$ 0.09

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)	Three months ended March 31, 2014	2013
Net earnings	$ 31,204	$ 17,246
Other comprehensive income (loss):		
Foreign currency translation adjustment, net of tax $nil and $149, respectively (notes 20(b)(iii) and 20(c))	23,556	25,344
Change in fair value of cash flow hedge, net of tax recovery of $3,868 and $738, respectively (note 20(b)(ii))	11,924	1,201
Change in unrealized pension and other post-retirement expense, net of tax expense of $207 and tax recovery of $5, respectively (note 8)	(450)	13
Other comprehensive income (loss), net of tax	35,030	26,558
Comprehensive income	66,234	43,804
Comprehensive income attributable to the non-controlling interests	9,542	9,619
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ 56,692	$ 34,185

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statement of Equity
(thousands of Canadian dollars)

For the three months ended March 31, 2014

	Common Shares	Preferred Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2013	$1,351,264	$116,546	$ 7,313	$ (488,406)	$ (31,410)	$510,654	$1,465,961
Net earnings/(loss)				35,852		(4,648)	31,204
Other comprehensive income					20,840	14,190	35,030
Dividends declared and distributions to non-controlling interests				(15,618)		(2,967)	(18,585)
Dividends and issuance of shares under dividend reinvestment plan	3,668			(3,668)			—
Contributions received from non-controlling interests	—	—	—	—	—	8,976	8,976
Issuance of common shares under employee share purchase plan	156			—			156
Share-based compensation			341				341
Preferred Series D shares, net of costs (note 9(b))		97,451		—			97,451
Acquisition of non-controlling interest (notes 3(a))			22,413	—	23,572	(205,796)	(159,811)
Balance, March 31, 2014	$1,355,088	$213,997	$ 30,067	$ (471,840)	$ 13,002	$320,409	$1,460,723

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.
Unaudited Interim Consolidated Statements of Cash Flows

(thousands of Canadian dollars)	Three months ended March 31, 2014	2013
Cash provided by (used in):		
Operating Activities:		
Net earnings from continuing operations	$ 30,931	$ 18,395
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	26,895	20,953
Amortization of intangible assets	1,079	1,039
Other amortization	391	576
Deferred taxes	10,727	6,158
Unrealized loss/(gain) on derivative financial instruments	3,113	(1,144)
Share-based compensation	341	420
Cost of equity funds used for construction purposes	(516)	—
Pension and post retirement expense	(236)	760
Write down of note receivable	698	—
Changes in non-cash operating items (note 19)	(58,203)	(50,995)
Changes in non-cash operating items from discontinued operations (note 19)	(193)	(954)
Cash provided/(used) in discontinued operations (note 12)	(192)	108
	14,835	(4,684)
Financing Activities:		
Cash dividends on common shares	(13,875)	(12,413)
Cash dividends on preferred shares	(1,350)	(1,350)
Cash contributions from non-controlling interests	8,976	—
Cash distributions to non-controlling interests	(2,967)	(178)
Issuance of common shares	156	29,426
Issuance of preferred shares, net of costs	96,533	—
Deferred financing costs	(1,309)	(314)
Increase in long-term liabilities	415,641	28,612
Decrease in long-term liabilities	(293,786)	(44,727)
Increase in advances in aid of construction	251	150
Decrease in other long-term liabilities	321	(756)
	208,591	(1,550)
Investing Activities:		
Decrease in restricted cash	(917)	(194)
Increase in other assets	(487)	(1,697)
Distributions received in excess of equity income	143	314
Receipt of principal on notes receivable	77	70
Additions to property, plant and equipment	(76,898)	(16,408)
Acquisitions of operating entities	(648)	(12,703)
Acquisition of non-controlling interest (note 3(a))	(127,260)	—
	(205,990)	(30,618)
Effect of exchange rate differences on cash	459	579
Increase/(decrease) in cash and cash equivalents	17,895	(36,273)
Cash and cash equivalents, beginning of the period	13,839	53,122
Cash and cash equivalents, end of the period	$ 31,734	$ 16,849

Supplemental disclosure of cash flow information:	2014	2013
Cash paid during the period for interest expense	$ 18,969	$ 13,217
Cash paid during the period for income taxes	$ 88	$ 283
Non-cash transactions		
Property, plant and equipment acquisitions in accruals	$ 13,213	$ 6,564

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp. ("APUC" or the "Company") is an incorporated entity under the Canada Business Corporations Act. APUC's principal activity is the ownership of power generation facilities and water, 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. 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.

1. Significant accounting policies

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 Article 10 of Regulation S-X 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, 2013 except for adopted accounting policies described in note 2.

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 typically higher than during cooler, wetter periods of the year. During the winter period, natural gas distribution utilities experience higher demand than during the summer period. Different electrical distribution utilities can experience higher or lower demand in the summer or winter depending on the specific regional weather, industry characteristics and existence of a decoupling mechanism.

2. Recently issued accounting pronouncements

(a) Recently adopted accounting pronouncements

The FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This newly issued accounting standard requires an entity to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except in some specific situations. The adoption of this standard did not have an impact the Company's financial position or results of operations.

The FASB issued ASU 2013-10, Derivatives and Hedging (Topic 815): Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes. This newly issued accounting standard permits the Fed Funds Effective Swap Rate (OIS) to be used as a U.S. benchmark interest rate for hedge accounting purposes under Topic 815, in addition to interest rates on direct Treasury obligations of the U.S. government and the London Interbank Offered Rate. The amendments also remove the restriction on using different benchmark rates for similar hedges. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2013-04, Liabilities (Topic 405): Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date. This newly issued accounting standard provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The adoption of this standard did not have an impact on the Company's financial position or results of operations.

(b) Recent accounting pronouncements not yet adopted

The FASB issued ASU 2014-08 Presentation of Financial Statements (Topic 205) and Property, Plant and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. This newly issued accounting standard raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. This ASU is required to be applied prospectively for fiscal years and interim periods beginning after December 15, 2014. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

3. Business acquisitions and development projects

(a) Acquisition of non-controlling interest in U.S. Wind farms

On March 31, 2014, APCo acquired the remaining 40% interest in Wind Portfolio SponsorCo, LLC ("SponsorCo") not owned by APCo for approximately U.S. $115,000. SponsorCo indirectly holds the interests in Sandy Ridge, Senate and Minonk Wind acquired in 2012. As a result of the transaction, APCo now owns 100% of SponsorCo resulting in the elimination of the non-controlling interest in respect of the Class B partnership units of SponsorCo as follows:

Elimination of non-controlling interest in Class B partnership units	$	205,796
Non-controlling interest portion of currency translation adjustment recorded to AOCI		(21,029)
Non-controlling interest portion of unrealized gain on cash flow hedges recorded to AOCI		(2,543)
Decrease in deferred tax asset		(32,551)
Additional paid-in capital		(22,413)
Cash	$	127,260

(b) Acquisition of New England Gas System

On December 20, 2013, Liberty Utilities acquired certain regulated natural gas distribution utility assets (the “New England Gas System”) located in the State of Massachusetts. Total purchase price for the New England Gas System, net of the debt assumed, is approximately $63,693 (U.S. $59,637), subject to certain working capital and other closing adjustments.

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

Working capital	$	8,263
Property, plant and equipment		83,022
Regulatory assets		47,632
Other assets		112
Long-term debt		(25,349)
Regulatory liabilities		(10,095)
Pension and OPEB		(25,374)
Environmental obligation		(12,877)
Deferred income tax liability, net		(1,158)
Other liabilities		(483)
Total net assets acquired	$	63,693

The Company has not completed the fair value measurements of the assets acquired and liabilities assumed. Currently, the determination of the fair value has been based upon management’s preliminary estimates of final closing adjustments, certain estimates and assumptions with respect to the fair values of the assets acquired and liabilities assumed. 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 above. The table above reflects an increase of U.S. $537 to the purchase price estimated on acquisition to reflect the latest information available.

3. Business acquisitions and development projects (continued)

(b) Acquisition of New England Gas System (continued)

Property, plant and equipment are amortized in accordance with regulatory requirements over the estimated useful life of the assets using the straight line method. The weighted average useful life of New England Gas System assets is 31 years.

All costs related to the acquisition have been expensed through the consolidated statements of operations.

New England Gas System contributed revenue of $48,581 and net earnings of $11,994 to the Company's consolidated financial results for three months ended March 31, 2014.

(c) Acquisition of Shady Oaks Wind Facility

Effective January 1, 2013, APCo acquired the 109.5 megawatt ("MW") Shady Oaks wind powered generating facility ("Shady Oaks Wind Facility"). The purchase agreement provides for final purchase price adjustments based on working capital at the acquisition date, energy generated by the project and basis differences between the relevant node and hub prices which are expected to be finalized in the third quarter of 2014. Changes in measurement of the final purchase price adjustment subsequent to December 31, 2013, the end of the business combination measurement period, are recorded in current period operations. To that effect, a gain of U.S. $643 was recognized in the three month period ended March 31, 2014.

(d) Development 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. As at March 31, 2014, the Company has invested $38,845 in the development and construction of the solar energy project which is recorded as property, plant and equipment, as well as additional amounts related to development rights and other intangibles, for a total investment of $44,707. The facility commenced commercial operations on March 27, 2014.

4. Accounts receivable

Accounts receivable as of March 31, 2014 includes unbilled revenue of $44,575 (December 31, 2013 - $45,274) from the Company's regulated utilities. Accounts receivable as at March 31, 2014 is presented net of allowance for doubtful accounts of $12,366 (December 31, 2013 - $8,461).

5. Regulatory matters

The Company's regulated utility operating companies 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 policies, 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 setting process.

At any given time, Liberty Utilities can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

5. Regulatory matters (continued)

On January 22, 2014, the Granite State Electric System entered a settlement with the New Hampshire Public Utilities Commission Staff in connection with its rate application filed on March 29, 2013. The settlement will provide for a rate increase of U.S. $10,875 consisting of U.S. $9,760 in base rates and an additional U.S. $1,115 for incremental capital expended after the test year. In addition, the settlement allows for a one time recovery of rate case expenses of U.S. $390. The settlement was approved on March 17, 2014 with the new permanent rates effective as of April 1, 2014 for effect with service rendered on and after July 1, 2013.

Regulatory assets and liabilities consist of the following:

	March 31, 2014	December 31, 2013
Regulatory assets		
Environmental costs	$ 87,601	$ 80,438
Pension and post-employment benefits	59,569	64,997
Energy costs adjustment	41,351	20,495
Storm costs	5,310	5,437
Debt premium	4,615	4,504
Rate case costs	3,390	3,119
Vegetation management	2,301	2,297
Rate adjustment mechanism	2,891	28
Asset retirement obligation	1,547	1,468
Tax related	3,354	2,995
Other	4,651	4,570
Total regulatory assets	$ 216,580	$ 190,348
Less current regulatory assets	(61,533)	(34,643)
Non-current regulatory assets	$ 155,047	$ 155,705
Regulatory liabilities		
Cost of removal	$ 71,807	$ 68,698
Rate-base offset	23,217	25,082
Energy costs adjustment	17,730	17,394
Pension and post-employment benefits	1,259	6,770
Rate adjustment mechanism	1,640	1,681
Tax related	138	133
Other	5,802	3,531
Total regulatory liabilities	$ 121,593	$ 123,289
Less current regulatory liabilities	(22,792)	(21,632)
Non-current regulatory liabilities	$ 98,801	$ 101,657

6. Long-term investments and notes receivable

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

	March 31, 2014	December 31, 2013
Long-term investments		
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 4,926	$ 4,851
25% of Class B non-voting shares of Cochrane Power Corporation	3,772	3,772
50% interest in the Valley Power Partnership	1,500	1,718
Other	338	325
Total long-term investments	$ 10,536	$ 10,666
Notes Receivable		
Red Lily Senior loan, interest at 6.31%	$ 11,588	$ 11,588
Red Lily Subordinated loan, interest at 12.5%	6,565	6,565
Chapais Énergie, Société en Commandite interest at 10.789% and 4.91%, respectively	1,090	1,928
Silverleaf resorts loan, interest at 15.48% maturing July 2020	2,234	2,149
Other	515	448
	21,992	22,678
Less: current portion	(614)	(598)
Total long-term notes receivable	$ 21,378	$ 22,080
Total long-term investments and notes receivable	$ 31,914	$ 32,746

7. Long-term liabilities

Long-term liabilities consist of the following:

	March 31, 2014	December 31, 2013
APCo		
Revolving credit facility	$ 105,128	$ 124,570
Senior unsecured notes	484,500	284,757
Senior Debt - Shady Oaks Wind Facility	90,651	129,759
Senior Debt - Long Sault Hydro Facility	36,879	37,143
Senior Debt - Sanger Thermal Facility:	21,225	20,421
Senior Debt - Chuteford Hydro Facility:	3,323	3,417
Liberty Utilities		
Revolving credit facility	75,395	85,620
Senior unsecured notes - Liberty Utilities Co.	403,508	388,214
Senior unsecured notes - Calpeco Electric System	77,385	74,452
Senior unsecured notes - Liberty Water Co	55,275	53,180
First mortgage bonds - New England Gas System	26,180	25,244
Senior unsecured notes - Granite State Electric System	16,583	15,954
IDA Bonds - LPSCo Water System	12,112	11,668
Loans - Bella Vista Water System	1,212	1,189
	$ 1,409,356	$ 1,255,588
Less: current portion	(8,647)	(8,339)
	$ 1,400,709	$ 1,247,249

APCo

On January 17, 2014, APCo issued $200,000 senior unsecured debentures bearing interest at 4.65% and with a maturity date of February 15, 2022. The debentures were sold at a price of $99.864 per $100.00 principal amount. Interest payments is payable on February 15 and August 15 each year, commencing on February 15, 2014. APCo incurred deferred financing costs of $1,282, which are being amortized to interest expense over the term of the loan using the effective interest rate method. Concurrent with the offering, APCo entered into a cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swap and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The gain or loss related to the fair value changes of the swap and the related foreign currency gains and losses on the USD accruals that are designated as, and are effective as, an economic hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment.

8. Pension and other post-employment benefits

The following tables list the components of net benefit costs for the pension plans and other post-employment benefits ("OPEB") recorded as part of administrative expenses in the consolidated statements of operations. The employee benefit costs related to business acquired are recorded in the consolidated statements of operations from the date of acquisition.

	Pension benefits	
	Three months ended March 31,	
	2014	2013
Service cost	$ 1,298	$ 625
Interest cost	2,044	962
Expected return on plan assets	(2,479)	(908)
Amortization of net actuarial (gain)/loss	(85)	3
Amortization of net regulatory assets/liabilities	498	$ 120
Net benefit cost	$ 1,276	$ 802

	OPEB	
	Three months ended March 31,	
	2014	2013
Service cost	$ 527	$ 288
Interest cost	541	306
Expected return on plan assets	(158)	(147)
Amortization of net actuarial (gain)/loss	(158)	9
Amortization of net regulatory assets/liabilities	43	$ 51
Net benefit cost	$ 795	$ 507

9. Shareholders' capital

(a) Common shares

Number of common shares:

	2014
Common shares, beginning of period	206,348,985
Issuance of shares under the dividend reinvestment and employee share purchase plans	518,085
Common shares, end of period	206,867,070

9. Shareholders' capital (continued)

(b) Preferred shares

On March 5, 2014, APUC issued 4,000,000 Series D Preferred shares, at a price of $25 per share, for aggregate proceeds of $100,000 before issuance costs of $3,467 or $2,549 net of taxes.

The holders of the Series D preferred shares are entitled to receive fixed cumulative preferential dividends at an annual rate of $1.25 per share, payable quarterly, as and when declared by the Board of Directors of APUC (the "Board"). The Series D Preferred shares yield 5.0% annually for the initial five-year period up to, but excluding March 31, 2019, with the first dividend payment occurring June 30, 2014. The dividend rate will reset on March 31, 2019, and every five years thereafter at a rate equal to the then five-year Government of Canada bond yield plus 3.28%. The Series D preferred shares are redeemable at $25 per share at the option of the Company on March 31, 2019, and on March 31 of every fifth year thereafter. The holders of Series D Preferred shares have the right to convert their shares into Cumulative Floating Rate Preferred shares, Series E ("the Series E Preferred shares"), subject to certain conditions, on March 31, 2019, and on March 31 of every fifth year thereafter. The Series E Preferred shares carry the same features as the Series D 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 3.28%. The holders of Series E Preferred shares will have the right to convert their shares back into Series D Preferred shares on March 31, 2019, and on March 31 of every fifth year thereafter. The Series D Preferred shares and the Series E Preferred shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

(c) Share-based compensation

During the three months ended March 31, 2014, 8,287 Deferred Share Units ("DSU") were issued pursuant to the election of the Directors to defer a percentage of their 2014 Director's fee in the form of DSUs.

For the three months ended March 31, 2014, APUC recorded $420 (2013 - $424) 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 unaudited interim consolidated statements of operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at March 31, 2014, total unrecognized compensation costs related to non-vested options and share unit awards were $1,442 and $71, respectively and are expected to be recognized over a period of 1.36 and 0.75 years, respectively.

10. Accumulated other comprehensive loss

Accumulated other comprehensive loss is comprised of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain on cash flow hedges	Pension and post-retirement actuarial loss	Total
Balance, January 1, 2013	$ (105,957)	$ 3,596	$ (2,506)	$ (104,867)
Other comprehensive income before reclassifications	48,486	10,357	16,698	75,541
Amounts reclassified from accumulated other comprehensive income	—	(2,113)	29	(2,084)
Net current period other comprehensive income	48,486	8,244	16,727	73,457
Balance, December 31, 2013	$ (57,471)	$ 11,840	$ 14,221	$ (31,410)
Other comprehensive income (loss) before reclassifications	27,232	(7,996)	—	19,236
Amounts reclassified from accumulated other comprehensive loss	—	2,054	(450)	1,604
Net current period other comprehensive income	27,232	(5,942)	(450)	20,840
Acquisition of non-controlling interest in U.S. Wind farms (note 3(a))	21,029	2,543	—	$ 23,572
Balance, March 31, 2014	$ (9,210)	$ 8,441	$ 13,771	$ 13,002

11. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the three months ended March 31, 2014, the Company declared dividends to shareholders on common shares totaling $17,584 (2013 - $15,847) or $0.0850 per common share (2013 - $0.0775 per common share). The Board declared a dividend on the Company's common shares of $0.0850 per share payable on January 15, 2014 to the shareholders of record on March 31, 2014.

For the three months ended March 31, 2014, the Company declared and paid dividends to Preferred Share, Series A holders totaling $1,350 (2013 - $1,350) or $0.28125 per Series A Preferred share (2013 - $0.28125 per Series A Preferred share).

For the three months ended March 31, 2014, the Company declared dividends to Preferred Share, Series D holders totaling $353 (2013 - $Nil) or $0.0882 per Series D Preferred share (2013 - $Nil per Series D Preferred share).

12. Divestitures

(a) EFW held for sale

During the second quarter of 2013, the Company initiated a strategic review of the Company's business plan and opportunities available for its Energy From Waste ("EFW Thermal Facility") and Brampton Cogeneration Inc. ("BCI Thermal Facility"). As a result of the review, the Company decided to sell the facilities. In 2013, the net assets of EFW and BCI were written down to their estimated fair value less cost of sale which resulted in a write down of the net assets of $56,851 before tax, or $42,538 net of tax of $14,313.

On February 7, 2014, the Company entered into an agreement to sell EFW and BCI Thermal Facilities and the transaction closed subsequent to quarter end, on April 4, 2014 for its estimated fair value.

12. Divestitures (continued)

(b) Sale of U.S. Hydro facilities

On June 29, 2013, APCo sold 9 small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of the Company, for gross proceeds of U.S. $23,400 for a gain on sale of U.S. $960, net of tax recovery of U.S. $1,605. The sale of the last small U.S. hydroelectric generating facilities is expected to close in 2014 for U.S. $3,600.

(c) Results from discontinued operations

The assets of EFW and BCI Thermal Facilities and the small U.S. hydroelectric facilities are presented as assets held for sale on the unaudited interim consolidated balance sheets and the operating results from these facilities are disclosed as discontinued operations on the unaudited interim consolidated financial statements.

The summary of operating results and cash flows from discontinued operations for the three months ended March 31 is as follows:

	2014	**2013**
Non-regulated energy sales	2,003	3,338
Waste disposal fees	2,122	1,913
Other and interest income	58	159
Operating and administrative expenses	(4,552)	(5,283)
Foreign exchange	49	25
Depreciation of property, plant and equipment	—	(1,554)
Interest expense	(12)	(44)
Gain on sale of assets	140	—
Deposit on sale	130	—
Loss from discontinued operations, before income taxes	(62)	(1,446)
Income tax recovery	335	297
Gain/(loss) from discontinued operations, net of income taxes	273	(1,149)
Add:		
Depreciation of property, plant and equipment	—	1,554
Write off of accounts receivable	(130)	—
Income tax recovery	(335)	(297)
Cash provided/(used) in discontinued operations	(192)	108

12. Divestitures (continued)

(c) Results from discontinued operations (continued)

Assets held-for-sale were as follows:

	March 31, 2014	December 31, 2013
Property, plant and equipment	$ 21,345	$ 21,193
Accounts receivable and prepaid expenses	3,230	2,734
Total assets held for sale, current	$ 24,575	$ 23,927

Liabilities held-for-sale were as follows:

	March 31, 2014	December 31, 2013
Accounts payable and accrued liabilities	$ 1,774	$ 1,471

13. Related party transactions

A member of the Board of Directors of APUC is an executive at Emera Inc. "Emera". For the three months ended March 31, 2014, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), a subsidiary of Emera, amounting to U.S. $1,515 (2013 - U.S. $1,635). For the three months ended March 31, 2014, Liberty Utilities purchased natural gas amounting to U.S. $2,977 (2013 - $1,331) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction.

There were no amounts outstanding related these transactions at the end of the periods.

Ian Robertson and Chris Jarratt ("Senior Executives"), respectively Chief Executive Officer and Vice-Chair of APUC partially own an entity from which APUC leases its head office facilities. Base lease costs for the three months ended March 31, 2014 were $79 (2013 - $84). The current office lease for a portion of its head office facilities expires on December 31, 2015. On January 3, 2014, through a wholly owned subsidiary, APUC acquired a new office facility from a third party . Occupancy is expected to occur in the third quarter of 2014 at which time the currently occupied premises will be subleased to third parties.

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

14. Non-controlling interests

Net earnings/(loss) attributable to non-controlling interests for the three months ended March 31, 2014 consist of the following:

	2014	2013
Net earnings attributable to Class B partnership units of SponsorCo	$ 3,483	$ 3,068
Net loss attributable to Class A partnership units	(8,490)	(5,032)
Other	359	—
Total net loss attributable to non-controlling interests	$ (4,648)	$ (1,964)

15. Income taxes

For the three months ended March 31, 2014, the Company's overall effective tax rate was different than the statutory rate of 26.50% (2013 - 26.50%) due primarily to recognition of deferred credits, higher tax rates in U.S. subsidiaries, minority interest partner's tax expenses, inter-corporate dividends, and non deductible expenses.

Included in deferred income tax expense for the three months ended March 31, 2014 is $3,377 (2013- $1,198) related to the recognition of deferred credits from the utilization of deferred income tax assets.

16. 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 common shareholders of the Company and the weighted average number of common 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 and shareholders' rights. 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.

The reconciliation of the net income and the weighted average shares used in the computation of basic and diluted earnings per share for the three months ended March 31, 2014 and 2013 are as follows:

	2014	2013
Net earnings attributable to shareholders of APUC	$ 35,852	$ 19,210
Series A preferred shares dividend (note 11)	1,350	1,350
Series D preferred shares dividend (note 11)	353	—
Net earnings attributable to common shareholders of APUC	$ 34,149	$ 17,860
Discontinued operations	273	(1,149)
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	$ 33,876	$ 19,009
Weighted average number of shares		
Basic	206,777,996	200,666,444
Dilutive effect of share-based awards	1,156,181	1,035,693
Diluted	207,934,177	201,702,137

The shares potentially issuable as a result of 816,402 stock options (2013 – 885,418) are excluded from this calculation as they are anti-dilutive.

17. Segmented information

APUC has two business units: 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 two operating segments: Renewable Energy and Thermal Energy. The Renewable Energy division operates the Company's hydro-electric, solar energy, and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities.

Within Liberty Utilities there are the following operating segments: Liberty Utilities (West), Liberty Utilities (Central) and Liberty Utilities (East). Liberty Utilities (West) is comprised of Calpeco Electric System and the water distribution and wastewater utilities located in Arizona. Liberty Utilities (Central) is comprised of the Midwest Gas System and the water distribution and wastewater utilities located in Arkansas, Texas, Missouri and Illinois. Liberty Utilities (East) is comprised of the New Hampshire Electric and Gas Systems, Peach State Gas System and New England Gas System.

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 any gains or losses on financial instruments to specific divisions. The unrealized portion of any gains or losses on derivatives instruments not designated in a hedging relationship is not considered in management's evaluation of divisional performance and is therefore allocated and reported in the corporate segment.

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

17. Segmented information (continued)

Operational segments (continued)

	Three months ended March 31, 2014								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 21,730	$ 36,434	$ 58,164	$ —	$ 58,164
Regulated gas sales and distribution	—	—	—	43,519	—	164,344	207,863	—	207,863
Regulated water reclamation and distribution	—	—	—	5,051	9,590	—	14,641	—	14,641
Non-regulated energy sales	44,061	14,339	58,400	—	—	—	—	—	58,400
Other revenue	3,001	765	3,766	—	2	681	683	—	4,449
Total revenue	47,062	15,104	62,166	48,570	31,322	201,459	281,351	—	343,517
Operating expenses	22,079	2,316	24,395	7,503	9,497	27,587	44,587	15	68,997
Regulated electricity purchased	—	—	—	—	11,468	22,712	34,180	—	34,180
Regulated gas purchased	—	—	—	30,072	—	109,395	139,467	—	139,467
Non-regulated fuel for generation	—	9,836	9,836	—	—	—	—	—	9,836
	24,983	2,952	27,935	10,995	10,357	41,765	63,117	(15)	91,037
Depreciation of property, plant and equipment	(11,862)	(1,461)	(13,323)	(3,046)	(3,667)	(6,561)	(13,274)	(298)	(26,895)
Amortization of intangible assets	(663)	(229)	(892)	(24)	(163)	—	(187)	—	(1,079)
Administration expenses	(3,303)	(85)	(3,388)	(672)	(1,315)	(1,972)	(3,959)	(380)	(7,727)
Foreign exchange gain	—	—	—	—	—	—	—	1,756	1,756
Interest expense	(8,189)	(381)	(8,570)	(1,413)	(2,184)	(3,454)	(7,051)	(578)	(16,199)
Interest, dividend and other income	388	(183)	205	95	325	403	823	1,166	2,194
Write down on note receivable	—	(698)	(698)	—	—	—	—	—	(698)
Gain on asset disposal	—	322	322	—	—	—	—	—	322
Acquisition related costs	(177)	—	(177)	—	—	(96)	(96)	—	(273)
Gain/(loss) on derivative financial instruments	2,098	—	2,098	—	—	—	—	(1,735)	363
Earnings/(loss) from continuing operations before income taxes	3,275	237	3,512	5,935	3,353	30,085	39,373	(84)	42,801
Earnings/(loss) from discontinued operations before income taxes	(384)	322	(62)	—	—	—	—	—	(62)
Earnings/(loss) before income taxes	$ 2,891	$ 559	$ 3,450	$ 5,935	$ 3,353	$ 30,085	$ 39,373	$ (84)	$ 42,739
Property, plant and equipment	$1,410,894	$ 82,939	$1,493,833	$ 228,944	$ 397,807	$ 693,418	$ 1,320,169	$ 47,376	$ 2,861,378
Intangible assets	27,319	5,700	33,019	2,791	19,801	—	22,592	—	55,611
Total Assets held for sale	4,012	20,563	24,575	—	—	—	—	—	24,575
Total assets	1,533,409	162,332	1,695,741	302,629	470,966	1,010,798	1,784,393	172,559	3,652,693
Capital expenditures	11,247	1,434	12,681	5,579	1,771	12,191	19,541	44,676	76,898
Acquisition of operating entities	—	—	—	—	—	648	648	—	648

17. Segmented information (continued)

Operational segments (continued)

	Three months ended March 31, 2013								
	Algonquin Power			Liberty Utilities				Corporate	Total
	Renewable Energy	Thermal Energy	Total	Central	West	East	Total		
Revenue									
Regulated electricity sales and distribution	$ —	$ —	$ —	$ —	$ 21,055	$ 21,800	$ 42,855	$ —	$ 42,855
Regulated gas sales and distribution	—	—	—	31,169	—	58,920	90,089	—	90,089
Regulated water reclamation and distribution	—	—	—	3,611	8,455	—	12,066	—	12,066
Non-regulated energy sales	38,807	8,122	46,929	—	—	—	—	—	46,929
Other revenue	717	650	1,367	—	14	—	14	—	1,381
Total revenue	39,524	8,772	48,296	34,780	29,524	80,720	145,024	—	193,320
Operating expenses	11,271	2,561	13,832	6,600	9,184	13,429	29,213	—	43,045
Regulated electricity purchased	—	—	—	—	11,571	14,432	26,003	—	26,003
Regulated gas purchased	—	—	—	20,842	—	38,208	59,050	—	59,050
Non-regulated fuel for generation	—	5,024	5,024	—	—	—	—	—	5,024
	28,253	1,187	29,440	7,338	8,769	14,651	30,758	—	60,198
Depreciation of property, plant and equipment	(11,022)	(1,331)	(12,353)	(1,965)	(2,983)	(3,652)	(8,600)	—	(20,953)
Amortization of intangible assets	(663)	(210)	(873)	(20)	(146)	—	(166)	—	(1,039)
Administration expenses	(2,503)	(254)	(2,757)	256	(707)	(469)	(920)	(1,183)	(4,860)
Foreign exchange gain	—	—	—	—	—	—	—	484	484
Interest expense	(6,474)	(593)	(7,067)	(100)	(1,951)	(2,765)	(4,816)	(316)	(12,199)
Interest, dividend and other income	384	244	628	39	639	372	1,050	541	2,219
Acquisition related costs	(77)	—	(77)	(47)	—	(369)	(416)	—	(493)
Gain on derivative financial instruments	437	—	437	—	—	—	—	949	1,386
Earnings/(loss) from continuing operations before income taxes	8,335	(957)	7,378	5,501	3,621	7,768	16,890	475	24,743
(Loss)/gain from discontinued operations before income taxes	688	(2,134)	(1,446)	—	—	—	—	—	(1,446)
Earnings/(loss) before income taxes	$ 9,023	$ (3,091)	$ 5,932	$ 5,501	$ 3,621	$ 7,768	$ 16,890	$ 475	$ 23,297
Capital expenditures	4,086	180	4,266	7,095	1,430	3,562	12,087	55	16,408
	December 31, 2013								
Property, plant and equipment	$1,364,843	$ 79,828	$1,444,671	$ 215,090	$ 387,715	$ 661,228	$1,264,033	$ —	$ 2,708,704
Intangible assets	26,802	5,698	32,500	2,709	19,207	—	21,916	—	54,416
Total Assets held for sale	3,860	20,067	23,927	—	—	—	—	—	23,927
Total assets	1,492,144	116,922	1,609,066	285,555	461,025	927,051	1,673,631	193,784	3,476,481

18. Commitments and contingencies

(a) 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.

i) On October 21, 2011 the Québec Court of Appeal ordered a subsidiary of APUC to pay approximately $5,400 (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. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $6,200. In 2012, the Company paid an amount of $1,884 to the government of Québec in relation to the early years covered by the claim in order to mitigate the impact of accruing interests on any amount ultimately determined to be payable or recoverable.

ii) 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, the New Hampshire Department of Environmental Services and the Massachusetts Department of Environmental Protection.

Like most other industrial companies, the gas and electric distribution utilities generate some hazardous waste. Under federal and state laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by Liberty Utilities, EnergyNorth Gas, Granite State Electric and New England Gas Systems 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 agency with authority for each of the respective sites. 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 undiscounted, unescalated cost of these MGP-related environmental cleanup activities will be $76,385 which at discount rates ranging from 1.4% to 3.15% represents the recorded accrual of $73,054 at March 31, 2014 (December 31, 2013 - $69,555).

By rate orders, the Regulator provided for the recovery of actual expenditures for site investigation and remediation over a period of 7 years and accordingly, at March 31, 2014 the Company has reflected a regulatory asset of $87,601 (December 31, 2013 - $80,438) for the MGP and related sites (note 5).

As a result of the dam safety legislation passed in Quebec (Bill C93), APUC has completed technical assessments on its hydroelectric facility dams owned or leased within the Province of Quebec. The assessments have identified a number of remedial measures required to meet the new safety standards. APUC currently estimates further capital expenditures of approximately $15,100 over a period of five years related to compliance with the legislation.

18. Commitments and contingencies (continued)

(b) Commitments (continued)

APUC has outstanding purchase commitments for power purchases, gas delivery, service and supply, 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	$ 76,701	$ 34,102	$ —	$ —	$ —	$ —	$ 110,803
Gas delivery, service and supply agreements	57,055	36,920	19,533	12,909	12,623	14,988	154,028
Service agreements	23,959	26,910	29,591	30,076	28,350	493,793	632,679
Capital projects	27,886	—	—	—	—	—	27,886
Operating leases	5,703	4,880	4,137	3,946	3,351	88,055	110,072
Total	$ 191,304	$102,812	$53,261	$46,931	$44,324	$596,836	$1,035,468

19. Non-cash operating items

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

	Three months ended March 31, 2014	Three months ended March 31, 2013
Accounts receivable	$ (537)	$ (673)
Prepaid expenses	(85)	(196)
Accrued liabilities	429	(85)
	$ (193)	$ (954)

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

	Three months ended March 31, 2014	Three months ended March 31, 2013
Accounts receivable	$ (44,449)	$ (35,243)
Related party balances	—	13
Natural gas inventory	19,170	9,577
Supplies and consumable inventory	(775)	(1,100)
Income tax receivable	(11)	(12)
Prepaid expenses	(70)	(3,114)
Accounts payable	(320)	(6,065)
Accrued liabilities	(10,312)	(18,065)
Current income tax liability	1,107	(91)
Net regulatory assets and liabilities	(22,543)	3,105
	$ (58,203)	$ (50,995)

20. Financial instruments

(a) Fair value of financial instruments

	March 31, 2014				
	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 21,992	$ 25,184	$ —	$ —	$ 25,184
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	20,585	20,585	—	—	20,585
Energy contracts not designated as a cashflow hedge	1,805	1,805	—	—	1,805
Commodity contracts for regulated operations	604	604	—	604	—
Total derivative financial instruments	22,994	22,994	—	604	22,390
Total financial assets	$ 44,986	$ 48,178	$ —	$ 604	$ 47,574
Long-term liabilities	$ 1,409,356	$ 1,457,698	$356,531	$1,101,167	$ —
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	9,525	9,525	—	—	9,525
Cross-currency swaps designated as a foreign exchange hedge	17,686	17,686	—	17,686	—
Interest rate swaps not designated as a hedge	2,790	2,790	—	2,790	—
Commodity contracts for regulated operations	74	74	—	74	—
Total derivative financial instruments	30,075	30,075	—	20,550	9,525
Total financial liabilities	$ 1,439,431	$ 1,487,773	$356,531	$1,121,717	$ 9,525

20. Financial instruments

(a) Fair value of financial instruments

December 31, 2013	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	$ 22,678	$ 26,321	$ —	$ —	$ 26,321
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	31,971	31,971	—	—	31,971
Energy contracts not designated as a cashflow hedge	3,737	3,737			3,737
Cross-currency swap designated as a foreign exchange hedge	109	109	—	109	—
Commodity contracts for regulatory operations	482	482	—	482	—
Total derivative financial instruments	36,299	36,299	—	591	35,708
Total financial assets	$ 58,977	$ 62,620	$ —	$ 591	$ 62,029
Long-term liabilities	$ 1,255,588	$ 1,261,340	$ 296,986	$ 964,354	$ —
Derivative financial instruments:					
Energy contracts designated as a cashflow hedge	4,781	4,781	—	—	4,781
Cross-currency swap designated as a foreign exchange hedge	7,947	7,947	—	7,947	—
Interest rate swaps not designated as a hedge	3,180	3,180	—	3,180	—
Commodity contracts for regulated operations	313	313	—	313	—
Total derivative financial instruments	16,221	16,221	—	11,440	4,781
Total financial liabilities	$ 1,271,809	$ 1,277,561	$ 296,986	$ 975,794	$ 4,781

20. Financial instruments (continued)

(a) Fair value of financial instruments (continued)

The Company has determined that the carrying value of its short-term financial assets and liabilities approximates fair value (a level 2 measurement) at March 31, 2014 and December 31, 2013 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.

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

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 $nil during the three months ended March 31, 2014 or 2013.

The Company's Level 3 fair value derivative instruments consist of energy contracts for energy sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from USD $16.48 to $174.24 as of March 31, 2014. The processes and methods of measurement are developed using the market knowledge of the trading operations within the Company and are derived from observable energy curves adjusted to reflect the illiquid market of the hedges and, in some cases, the variability in deliverable energy. Significant increases (decreases) in any of these inputs in isolation would result in a significantly lower (higher) fair value measurement. The change in the fair value of the energy contracts are detailed in notes 20(b)(ii) and 20(b)(iv).

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 months ended March 31, 2014 or 2013.

(b) Derivative instruments

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

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 included in the calculation of deferred gas costs (note 5).

20. Financial instruments (continued)

(b) Derivative instruments (continued)

(i) Commodity derivatives – regulated accounting (continued)

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

	2014
Financial contracts: Gas swaps	1,422,004
Gas options	1,358,504
	2,780,508

(ii) Cash flow hedges

APCo reduces the price risk on the expected future sale of power generation at Sandy Ridge, Senate and Minonk Wind Facilities and at one of its hydro facilities 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)
Energy delivered less existing swap	December 2014	U.S. $	32.64	PJM Western HUB
Energy delivered less existing swap	December 2014	U.S. $	25.64	NI HUB
Energy delivered less existing swap	December 2014	U.S. $	27.39	ERCORT North HUB
138,060	December 2016	$	67.46	AESO
992,046	December 2022	U.S. $	42.81	PJM Western HUB
4,248,940	December 2022	U.S. $	30.25	NI HUB
4,552,263	December 2027	U.S. $	36.46	ERCORT North HUB

As at March 31, 2014, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of $6,499 (December 31, 2013 - $7,344) was held as collateral by the counterparty.

20. Financial instruments (continued)

(b) Derivative instruments (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in other comprehensive income attributable to derivative financial instruments designated as a hedge:

	Three months ended March 31, 2014	2013
Effective portion of cash flow hedge, gain	$ (11,916)	$ 2,498
Gain (loss) realized on cash flow hedge	(8)	(7)
	$ (11,924)	$ 2,491
Less non-controlling interest	5,982	(1,290)
Change in fair value of cash flow hedge in other comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	$ (5,942)	$ 1,201

The Company expects $2,128 of unrealized gains currently in accumulated other comprehensive loss to be reclassified into net earnings within the next twelve months, as the underlying hedged transactions settle.

The ineffective portion of derivative financial instruments designated as a hedge is recorded as part of loss/(gain) on derivative financial instruments on the consolidated statement of operations (note 20(b)(iv)).

(iii) Foreign exchange hedge of net investment in foreign operation

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.

Concurrent with its $150,000 and $200,000 debentures offering in December 2012 and January 2014, respectively, APCo entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. APCo designated the entire notional amount of the cross currency fixed for fixed interest rate swaps and related short-term USD payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in APCo's U.S. operations. The gain or loss related to the fair value changes of the swaps and the related foreign currency gains and losses on the USD accruals that are designated as, and are effective as, a hedge of the net investment in a foreign operation are reported in the same manner as the translation adjustment (in other comprehensive income) related to the net investment. A foreign currency loss of $9,970 (2013 - $1,010) was recorded in other comprehensive income in 2014.

(iv) 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 classified as derivative instruments. The electricity derivative contracts are net settled fixed-for-floating swaps whereby APUC pays a fixed price and receives the floating or indexed price on a notional quantity of energy over the remainder of the contract term at an average rate, as per the following table. These contracts are not accounted for as hedges and changes in fair value are recorded in earnings as they occur.

Notional quantity (MW-hrs)	Expiry	Receive average prices (per MW-hr)	Net Asset
42,838	March 2015	U.S. $46.75	1,587

20. Financial instruments (continued)

(b) Derivative instruments (continued)

(iv) Other derivatives (continued)

For derivatives that are not designated as cash flow hedges, and for the ineffective portion of gains and losses on derivatives that are accounted as 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 hedges consist of the following:

	Three months ended March 31, 2014	2013
Change in unrealized loss/(gain) on derivative financial instruments:		
Interest rate swaps	$ (390)	$ (284)
Energy derivative contracts	2,160	(665)
Total change in unrealized loss/(gain) on derivative financial instruments	$ 1,770	$ (949)
Realized loss/(gain) on derivative financial instruments:		
Interest rate swaps	490	486
Energy derivative contracts	(3,966)	(738)
Total realized loss on derivative financial instruments	$ (3,476)	$ (252)
Gain on derivative financial instruments accounted for as hedges	$ (1,706)	$ (1,201)
Ineffective portion of derivatives financial instruments accounted for as hedges	$ 1,343	(185)
Gain on derivative financial instruments	$ (363)	$ (1,386)

(c) Risk management

Foreign currency risk

The Company is exposed to currency fluctuations from its U.S. based operations. APUC manages this risk primarily through the use of natural hedges by using U.S. long-term debt to finance its U.S. operations.

APCo designates 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 loss of $1,128 was recorded in other comprehensive income during the three months ended March 31, 2014 (2013 -$310).

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.

APCo is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of $62,169 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At March 31, 2014, the estimated fair value of the interest rate swap was a liability of $2,790 (December 31, 2013 – liability of $3,180). 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.

21. Comparative figures

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

CORPORATE INFORMATION

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Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.
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Christopher Huskilson – President & Chief Executive Officer, Emera Inc.
Chris Jarratt – Vice-Chair, Algonquin Power & Utilities Corp.
Ian Robertson – Chief Executive Officer, Algonquin Power & Utilities Corp.
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