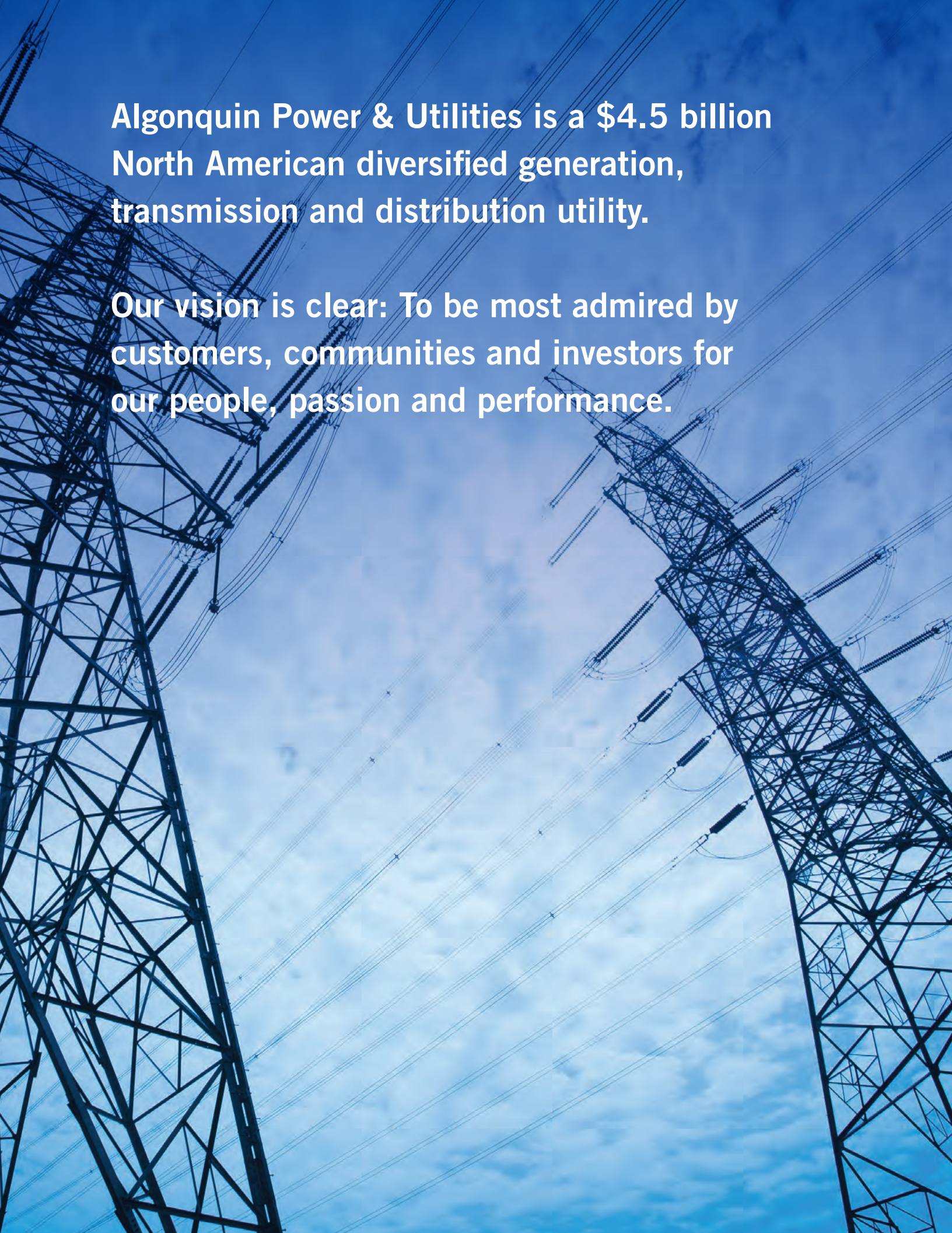




Q1 2015

A low-angle, upward-looking photograph of several high-voltage electrical transmission towers and their associated power lines. The towers are constructed from a complex lattice of metal beams. The power lines stretch across the frame, creating a sense of depth and scale. The background is a clear, bright blue sky with some light, wispy clouds. The overall image has a blue tint, giving it a professional and industrial feel.

**Algonquin Power & Utilities is a \$4.5 billion
North American diversified generation,
transmission and distribution utility.**

**Our vision is clear: To be most admired by
customers, communities and investors for
our people, passion and performance.**

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, 2015. The Management Discussion & Analysis (“MD&A”) should be read in conjunction with APUC’s unaudited interim consolidated financial statements for the three months ended March 31, 2015 and 2014. The MD&A should also be read in conjunction with APUC’s annual audited consolidated financial statements for the years ended December 31, 2014 and 2013, and the annual MD&A for the year ended December 31, 2014. Additional information about APUC, including the most recent Annual Information Form (“AIF”) can be found on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

This MD&A is based on information available to management as of May 8, 2015.

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 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 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 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 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 measure 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, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Adjusted net earnings

Adjusted net earnings is a non-GAAP measure 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, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other typically non-recurring items 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 measure 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 typically non-recurring items 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 measure 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 measure 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 U.S. \$0.09625 per share or U.S. \$0.3850 per share per annum. Based on exchange rates as at March 31, 2015, the quarterly dividend is equivalent to CAD \$0.12 per share or CAD \$0.49 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's operations are organized across three business units consisting of Generation, Transmission and Distribution. The Generation Business Group ("Generation Group") owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets; the recently formed Transmission Business Group ("Transmission Group") is responsible for evaluating and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America; and the Distribution Business Group ("Distribution Group") owns and operates a portfolio of North American electric, natural gas and water distribution and wastewater collection utility systems.

Generation Business Group

The Generation Group 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. The Generation Group seeks to deliver continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Generation Group owns or has interests in hydroelectric, wind, and solar facilities with a combined generating capacity of approximately 120 MW, 700 MW, and 30 MW, respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long-term contractual arrangements which have a weighted average remaining contract life of 14 years.

The Generation Group owns or has interests in thermal energy facilities with approximately 335 MW of installed generating capacity. Approximately 91% of the electrical output from the owned thermal facilities is sold pursuant to long term power purchase agreements ("PPA") with major utilities, which have a weighted average remaining contract life of 7 years.

The Generation Group also has a portfolio of development projects that between 2016 and 2018 will add approximately 486 MW of generation capacity from wind and solar powered generating stations with an average contract life of 23 years.

Distribution Business Group

The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 489,000 connections. The Distribution Group 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, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

The Distribution Group's regulated electrical distribution utility systems and related generation assets are located in the States of California and New Hampshire; and together serve approximately 93,000 electric connections.

The Distribution Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, Missouri and New Hampshire; and together serve approximately 293,000 natural gas connections.

The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, Illinois, Missouri, and Texas; and together serve approximately 103,000 connections.

Transmission Business Group

The Transmission Group complements the growth of both the Generation and Distribution Groups and is responsible for identifying, evaluating and capitalizing upon natural gas pipeline and electric transmission investment opportunities in North America.

Major Highlights

2015 Corporate Highlights

Dividend Increased to U.S. \$0.385 Per Common Share Annually

APUC targets a 10% annual growth in dividends payable to shareholders underpinned by increases in earnings and cashflow. Management believes that the increase in dividends is consistent with APUC's stated strategy of delivering total shareholder return comprised of attractive current dividend yield and capital appreciation.

APUC has completed several acquisitions and has advanced on other growth initiatives including its power development projects that have continued to raise the growth profile of the company. These increased earnings and cash flows are now evident in the first quarter results and support an increase in the dividend to shareholders. As a result, on May 7, 2015, the Board approved a dividend increase of U.S. \$0.035 annually bringing the total annual dividend to U.S. \$0.385 per common share, paid quarterly at the rate of \$0.09625 per common share an increase of 10% over the previous dividend rate.

2015 Generation Group Highlights

Completion of Morse Wind Project

Subsequent to quarter end, on April 22, 2015 the Generation Group completed construction on the Morse Wind Project, located near Morse, Saskatchewan. The project is the company's eighth wind generating facility, and consists of 10 2.3 MW direct drive wind turbine generators installed over 1,120 acres of land. The project is expected to generate 104 GW-hrs of energy per year which is being sold under a 20 year power purchase agreement with a large investment grade electric utility.

Completion of Bakersfield I Solar Project

Subsequent to quarter end, on April 14, 2015 the Generation Group completed final construction on the Bakersfield I Solar Project, located in Kern County, California. The project is the Generation Group's second solar generating facility and is comprised of approximately 85,000 solar panels located on 165 acres of land. The project is expected to generate 53.3 GW-hrs of energy per year which is being sold under a 20 year power purchase agreement with a large investment grade electric utility.

Consistent with the commitment to expand its solar generation portfolio, the Generation Group is currently pursuing the construction of the 10 MW Bakersfield II Solar Generation Project immediately adjacent to the Bakersfield I Solar Generation Project, which is estimated to be operational in the first half of 2016.

2015 Distribution Group Highlights

Acquisition of New Hampshire Gas

On January 2, 2015, the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System was approximately U.S. \$3.0 million, subject to certain closing adjustments.

Successful Rate Case Outcomes

A core strategy of the Distribution Group is to ensure appropriate return on the rate base at its various utility systems. During the first quarter of 2015, the Distribution Group began implementation of new rates in four utilities representing a cumulative annual revenue increase of approximately U.S. \$14.3 million. Further details on these and other regulatory proceedings of the Distribution Group can be found later in this MD&A under Regulatory Proceedings.

U.S. Debt Private Placement

Subsequent to quarter end, on April 30, 2015, the Distribution Group issued U.S. \$160.0 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing will be used to partially finance the acquisition of the Park Water System and for general corporate purposes. The funds are being

drawn in two tranches: U.S. \$90 million was drawn immediately on closing and U.S. \$70 million will be drawn in the third quarter. The notes have been assigned a rating of BBB High by DBRS.

The financing is the fourth series of notes issued pursuant to the company's master indenture.

2015 Three Months Results From Operations

Key Selected First Quarter Financial Information

(all dollar amounts in \$ millions except per share information)	Three months ended March 31,	
	2015	2014
Revenue	\$ 381.9	\$ 343.0
Adjusted EBITDA ¹	114.5	98.3
Cash provided/(used) by operating activities	(7.4)	14.8
Adjusted funds from operations ¹	101.0	82.7
Net earnings attributable to Shareholders from continuing operations	43.1	35.6
Net earnings attributable to Shareholders	43.1	35.9
Adjusted net earnings ¹	42.5	36.9
Dividends declared to Common Shareholders	27.9	17.6
Weighted Average number of common shares outstanding	250,776,336	206,777,996
Per share		
Basic net earnings from continuing operations	\$ 0.16	\$ 0.16
Basic net earnings	\$ 0.16	\$ 0.17
Adjusted net earnings ^{1, 2}	\$ 0.17	\$ 0.17
Diluted net earnings	\$ 0.16	\$ 0.16
Cash provided/(used) by operating activities ^{1, 2}	\$ (0.03)	\$ 0.07
Adjusted funds from operations ^{1, 2}	\$ 0.41	\$ 0.39
Dividends declared to Common Shareholders	\$ 0.11	\$ 0.09
Total assets	4,531.4	4,102.7
Long term liabilities ³	1,482.7	1,269.3

¹ Non-GAAP Financial Measure (See "Non-GAAP Financial Measures for further detail")

² APUC uses per share adjusted net earnings, cash provided/(used) by operating activities and adjusted funds from operations to enhance assessment and understanding of the performance of APUC.

³ Includes long-term liabilities and current portion of long-term liabilities

For the three months ended March 31, 2015, APUC experienced an average U.S. exchange rate of approximately \$1.2411 as compared to \$1.1039 in the same period in 2014. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's Canadian dollar reporting currency.

For the three months ended March 31, 2015, APUC reported total revenue of \$381.9 million as compared to \$343.0 million during the same period in 2014, an increase of \$38.9 million or 11.3%. The major factors resulting in the increase in APUC revenue for the three months ended March 31, 2015, as compared to the corresponding period in 2014 are set out as follows:

Three months ended
March 31

(all dollar amounts in \$ millions)

Comparative Prior Period Revenue	\$	343.0
Significant Changes:		
Decreased wind resources at all facilities other than Sandy Ridge partially offset by favorable settlements on periodic production shortfalls under power hedges at the Minonk, Senate and Sandy Ridge Wind Facilities along with higher pricing realized on sale of the unhedged portion of energy produced.		0.5
Full quarter of commercial operations at St. Damase Wind Facility		2.0
Full quarter of commercial operations at the Cornwall Solar Facility		1.0
Decreased customer load and retail pricing in the Maritime region		(3.2)
Higher realized prices from Renewable Energy Credits from the U.S. Wind facilities partially offset by decrease in sales of Renewable Energy Credits at the Windsor Locks Thermal Facility		1.3
Decreased production at the Windsor Locks Thermal Facility and lower realized pricing at the Windsor Locks and Sanger Thermal Facilities		(4.2)
Decrease in Natural Gas Systems and Electric Systems Revenue due to lower commodity cost which are a direct pass-through to customers and decreased usage at the Granite State Electric System due, partially offset by higher demand at the Energy North Gas and New England Gas Systems due to a higher number of heating degree days.		(6.6)
Increased revenue of \$7.0 million due to rate case impacts at the Pine Bluff Water, LPSCo Water, EnergyNorth Gas, Peach State Gas, Illinois Gas, and Missouri Gas Systems, partially offset by \$1.6 million of rate increases at the Granite State Electric System which related to 2013 but was recognized in the first quarter of 2014.		5.4
Increase in revenue due to acquisition of New Hampshire Gas operations		1.9
Increased revenues at Peach State Gas System's Fort Benning operations		1.3
Impact of the stronger U.S. dollar		39.2
Other		0.3
Current Period Revenue	\$	381.9

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

Adjusted EBITDA in the three months ended March 31, 2015 totalled \$114.5 million as compared to \$98.3 million during the same period in 2014, an increase of \$16.2 million or 16.5%. The increase in Adjusted EBITDA was primarily due to impact of rate case settlements, start of production of the St. Damase Wind Facility and Cornwall Solar Facility and a stronger US Dollar. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings section. (see Non-GAAP Performance Measures).

For the three months ended March 31, 2015, net earnings from continuing operations attributable to Shareholders totalled \$43.1 million as compared to \$35.6 million during the same period in 2014, an increase of \$7.5 million. The increase was due to \$21.6 million in increased earnings from operating facilities, \$0.3 million increase in interest and dividends, \$3.6 million in increased allocations of earnings to non-controlling interests, \$1.1 million increase in other gains, and a decrease of \$0.5 million in property plant and equipment write-downs as compared to the same period in 2014. These items were partially offset by \$8.1 million in increased depreciation and amortization expenses, \$2.7 million in increased administration charges, \$0.4 million in increased interest expense, \$0.5 million in decreased foreign currency, \$0.3 million in decreased gain from derivative instruments and \$7.5 million in increased income tax expense (tax explanations are discussed in *APUC: Corporate and Other Expenses*), as compared to the same period in 2014.

For the three months ended March 31, 2015, net earnings (including discontinued operations) attributable to Shareholders totalled \$43.1 million as compared to \$35.9 million during the same period in 2014, an increase of \$7.2 million. Net earnings per share totalled \$0.16 for the three months ended March 31, 2015, as compared to \$0.17 during the same period in 2014.

During the three months ended March 31, 2015, cash used by operating activities totalled \$7.4 million or \$0.03 per share as compared to cash provided by operating activities of \$14.8 million, or \$0.07 per share during the same period in 2014. During the three months ended March 31, 2015, adjusted funds from operations, a non-GAAP measure, totalled \$101 million or \$0.41 per share as compared to adjusted funds from operations of \$82.7 million, or \$0.39 per share during the same period in 2014, an increase of \$18.3 million.

Cash per share provided/used by operating activities and per share adjusted funds from operations are non-GAAP measures. Per share cash provided/used 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/used 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.

GENERATION BUSINESS GROUP

Renewable Energy Division

	Long Term Average Resource	Three Months ended March 31	
		2015	2014
Performance (GW-hrs sold)			
Hydro Facilities:			
Maritime Region	35.7	27.3	33.7
Quebec Region ¹	57.1	48.7	48.6
Ontario Region	38.3	37.8	37.4
Western Region	9.6	11.2	12.4
	140.7	125.0	132.1
Wind Facilities:			
St. Damase ²	20.9	20.5	—
St. Leon	121.4	123.9	132.9
Red Lily ³	23.2	22.4	27.5
Sandy Ridge	47.1	49.8	44.7
Minonk	200.6	176.7	199.3
Senate	151.3	109.3	147.7
Shady Oaks	109.7	100.0	112.7
	674.2	602.6	664.8
Solar Facilities:			
Cornwall	3.2	2.3	0.6
Total Performance	818.1	729.9	797.5

¹ The Generation Group's Donnacona Hydro Facility was offline during the first quarter of 2015. Insurance proceeds were received to compensate for lost revenue.

² The St Damase Wind Facility achieved commercial operation on December 2, 2014.

³ 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.

For the three months ended March 31, 2015, the Renewable Energy Division generated 729.9 GW-hrs of electricity. This level of production represents sufficient energy to supply the equivalent of 54,133 homes on an annualized basis with renewable power. As a result of renewable energy production, the equivalent of 535,300 tons of CO₂ gas was prevented from entering the atmosphere.

Three months ended March 31

(all dollar amounts in \$ millions)

2015

2014

Revenue¹			
Hydro	\$	16.0	\$ 18.6
Wind		30.1	24.9
Solar		1.1	0.1
Total Revenue	\$	47.2	\$ 43.6
Less:			
Cost of Sales - Energy ²		(6.2)	(10.4)
Realized gain/(loss) on hedges ³		0.6	4.0
Net Energy Sales	\$	41.6	\$ 37.2
Renewable Energy Credits ("REC") ⁴		4.6	2.4
Other Revenue		0.4	0.6
Total Net Revenue	\$	46.6	\$ 40.2
Expenses & Other Income			
Operating expenses		(12.6)	(11.2)
Interest and Other income		0.8	0.4
HLBV income/(loss)		8.9	8.5
Divisional operating profit	\$	43.7	\$ 37.9

¹ While most of the Generation Group's PPAs include annual rate increases, a change to the weighted average production levels resulting in higher average production from facilities that earn lower energy rates can result in a lower weighted average energy rate earned by the division, as compared to the same period in the prior year.

² Cost of Sales - Energy consists of energy purchases in the Maritime Region to supplement the energy sales from the Tinker Facility which is sold to retail and industrial customers under multi-year contracts.

³ See financial statements note 20(b)(iv).

⁴ Qualifying renewable energy projects receive Renewable Energy Credits (RECs) for the generation and delivery of renewable energy to the power grid. The energy credit certificates represent proof that 1 MW of electricity was generated from an eligible energy source. The RECs can be traded and the owner of the REC can claim to have purchases of renewable energy. REC revenue is recognized only at the time a generated REC unit is matched up with a previously signed REC sales contract with a third party. Generated REC units not immediately available to match against a signed contract are recorded as inventory with the offset recorded as a decrease in operating expenses.

2015 Three Month Operating Results

For the three months ended March 31, 2015, the hydro facilities generated 125.0 GW-hrs of electricity, as compared to 132.1 GW-hrs produced in the same period in 2014, a decrease of 5.4%. The decrease in generation is largely attributable to below seasonal temperatures in the Maritime region resulting in lower hydrology in the first quarter of 2015 combined with the Donnacona Hydro Facility in Quebec being offline.

During the three months ended March 31, 2015, the hydro facilities generated electricity equal to 88.8% of long-term projected average resources, as compared to 93.9% during the same period in 2014. During the three months ended March 31, 2015, the Western Region Hydros achieved production above its long-term average while the Quebec, Ontario and Maritime region produced below their long term average. The Quebec region achieved 85% of its long term average primarily as a result of the Donnacona Hydro Facility being offline during the quarter. Excluding the Donnacona Hydro Facility, the Quebec region would have achieved 91% of its long term average.

For the three months ended March 31, 2015, revenue from the hydro facilities totalled \$16.0 million, as compared to \$18.6 million during the same period in 2014, a decrease of \$2.6 million. Revenue from generation in the Ontario region increased by \$0.3 million due to improved production at the Long Sault Hydro Facility, while the Western region experienced a decrease of \$0.1 million which was the result of lower production compared to the same quarter in the prior year and lower market pricing on the unhedged portion of production. The weighted average market price experienced by the Western region fell by almost 60% from the unusually high prices of 2014. Revenue in the Quebec region was flat as compared to the prior period,

despite the outage at the Donnacona Hydro Facility due to lost revenues being mainly offset by business interruption insurance proceeds. Revenue from the Maritime region decreased \$2.8 million, primarily due to decreased retail customer load served combined with approximately a 22% reduction in the average revenue rate.

For the three months ended March 31, 2015, energy purchases related to the Maritime region totalled \$6.2 million, as compared to \$10.4 million during the same period in 2014, a decrease of \$4.2 million. The decrease in energy purchases for the three months ended March 31, 2015 was a result of the lower retail customer load which decreased the overall energy purchase requirement. In addition, the average energy purchase price was significantly lower than the abnormally high prices of the prior year, which resulted in the decrease in energy costs. During this period, purchases of approximately 52.1 GW-hrs of energy at market and fixed rates averaging U.S. \$87 per MW-hr were made. During the three months ended March 31, 2015, the Maritime region generated approximately 20% of the load required to service its customers, as compared to 21% in the same period in 2014. To mitigate the risk of higher average energy prices, the Maritime region had previously entered into certain power hedges as part of its risk mitigation strategies. For the three months ended March 31, 2015, \$0.6 million was realized in connection with these hedges and is recorded as a realized gain on derivative financial instruments on the unaudited interim Consolidated Statement of Operations. Net energy sales at the Maritime region totalled \$1.3 million for three months ended March 31, 2015 as compared to \$3.3 million in the same quarter in the prior year a decrease of \$2.0 million.

For the three months ended March 31, 2015, the wind facilities produced 602.6 GW-hrs of electricity, as compared to 664.8 GW-hrs produced in the same period in 2014, a decrease of 9.4%. The decreased generation was a result of weaker wind resources at all facilities except the Sandy Ridge Wind Facility, offset partly by generation from the new St. Damase Wind Facility which achieved commercial operation on December 2, 2014 and therefore was operational for the entire first quarter of 2015.

During the three months ended March 31, 2015, the wind facilities generated electricity equal to 89.4% of long-term average resources, as compared to 98.6% during the same period in 2014. For the three months ended March 31, 2015, revenue from the wind facilities totalled \$30.1 million, as compared to \$24.9 million during the same period in 2014, an increase of \$5.2 million. Revenue from the Generation Group's Canadian wind facilities increased \$1.4 million primarily due to the St. Damase Wind Facility being fully operational for the entire quarter which was partially offset by weaker production at the remaining facilities. Revenue from the U.S. wind facilities increased \$3.7 million primarily as a result of favorable settlements on periodic production shortfalls under the power hedges at the Minonk, Senate and Sandy Ridge Wind Facilities along with higher pricing realized on sales of the unhedged portion of energy produced. These favorable variances were partially offset by lower production at all of the facilities other than Sandy Ridge. The stronger U.S. dollar exchange rate also contributed to the increase.

For the three months ended March 31, 2015, REC revenue totalled \$4.6 million, as compared to \$2.4 million in the same period in 2014, an increase of \$2.2 million. The increase is primarily a result of a stronger U.S. exchange rate and higher market prices of RECs for the three sites in the PJM market (Minonk, Sandy Ridge and Shady Oaks), with Minonk realizing the most significant increase of approximately 180% over the same period in the prior year. The increases were partially offset by lower volume of RECs sold due to lower production. REC units are generated at a ratio of one REC unit per one MW-hr generated and are sold in the market in which the REC is generated.

During the three months ended March 31, 2015, the Generation Group's solar facility located in Ontario generated 2.3 GW-hrs of electricity, which is equal to 71.9% of long-term average resources. Production was below long term averages primarily due to above normal levels of snow and ice accumulation on the panels. The facility reached commercial operation on March 27, 2014 and has a 20 year Feed in Tariff PPA with the Ontario Power Authority. Revenue from generation totalled \$1.1 million for the period as compared to \$0.1 million in the prior year an increase of \$1.0 million. The increase is due to the facility being fully operational for the first quarter of 2015.

For the three months ended March 31, 2015, operating expenses excluding energy purchases totalled \$12.6 million, as compared to \$11.2 million during the same period in 2014, an increase of \$1.4 million. The increase was primarily due to the appreciation of the U.S. dollar, additional safety training costs at various facilities, and a full quarter of operating costs for Cornwall Solar.

For the three months ended March 31, 2015, interest and other income totalled \$0.8 million, as compared to \$0.4 million during the same period in 2014. Interest and other income primarily consist of interest related to the senior and subordinated debt interest in Red Lily I Wind Facility.

The Red Lily I Wind Facility located in Saskatchewan produced 22.4 GW-hrs of electricity for the three months ended March 31, 2015. The Generation Group's economic return from its investment in Red Lily currently comes in the form of interest payments (as discussed above), fees and other charges and is not reflected in revenue from energy sales. Under the terms of the agreements, the Generation Group has the right to exchange these contractual and debt interests in the Red Lily I Wind Facility for a direct 75% equity interest in 2016. For the three months ended March 31, 2015, the Generation Group earned fees of \$0.4 million (which is classified as other revenue) and interest income of \$0.4 million from the Red Lily I Wind Facility.

Hypothetical Liquidation at Book Value (“HLBV”) income represents the value of net tax attributes, primarily related to electricity production generated by the Generation Group in the period from certain of its U.S. wind and solar power generation facilities. The value of net tax attributes generated in the three months ended March 31, 2015 amounted to an approximate HLBV income of \$8.9 million, as compared to \$8.5 million in the prior year. The increase of \$0.4 million was primarily a result of \$1.1 million of HLBV income from the Bakersfield Solar Facility (which was placed in service on December 30, 2014), \$1.0 million due to a stronger U.S. dollar, and a higher income allocation to the Generation Group due to the reduced economic interest of Tax Equity investors in the projects. This was offset by a \$2.0 million decrease due to lower production at the U.S. wind facilities.

For the three months ended March 31, 2015, the Renewable Energy Division’s operating profit totalled \$43.7 million, as compared to \$37.9 million during the same period in 2014, an increase of \$5.8 million; \$3.0 million of the increase is attributable to the stronger U.S. dollar.

GENERATION BUSINESS GROUP

Thermal Energy Division

	Three months ended March 31, 2015			Three months ended March 31, 2014		
	Windsor Locks	Sanger	Total	Windsor Locks	Sanger	Total
Performance (GW-hrs sold)	28.0	31.9	59.9	32.7	32.0	64.7
Performance (steam sales – billion lbs)	196.3	—	196.3	201.2	—	201.2
(all dollar amounts in \$ millions)						
Revenue						
Energy/steam sales	\$ 7.8	\$ 2.7	\$ 10.5	\$ 10.9	\$ 3.4	\$ 14.3
Less:						
Cost of Sales – Fuel	(5.7)	(1.5)	(7.2)	(8.0)	(1.8)	(9.8)
Net Energy/Steam Sales	\$ 2.1	\$ 1.2	\$ 3.3	\$ 2.9	\$ 1.6	\$ 4.5
Other revenue	0.3	0.6	0.9	0.6	0.2	0.8
Total net revenue	\$ 2.4	\$ 1.8	\$ 4.2	\$ 3.5	\$ 1.8	\$ 5.3
Expenses						
Operating expenses	(1.3)	(1.2)	(2.5)	(1.3)	(1.0)	(2.3)
Facility operating profit	\$ 1.1	\$ 0.6	\$ 1.7	\$ 2.2	\$ 0.8	\$ 3.0
Interest and other income (loss)			\$ 0.2			\$ (0.2)
Divisional operating profit			1.9			2.8

2015 Three Month Operating Results

The Generation Group’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.

Production data, revenue and expenses have been adjusted to remove the results of the EFW and BCI Thermal Facilities, which were divested on April 4, 2014 for proceeds approximating the carrying value of the net assets on the unaudited interim Consolidated Balance Sheet of the Company as at March 31, 2014. The results of the EFW and BCI Thermal Facilities for the period up to the date of sale are reported as discontinued operations.

For the three months ended March 31, 2015, the Thermal Energy Division’s operating profit was \$1.9 million, as compared to \$2.8 million in the same period in 2014, a decrease of \$0.9 million. The Windsor Locks Thermal Facility contributed \$1.1 million, while the Sanger Thermal Facility contributed \$0.6 million of operating profit during the three months ended March 31, 2015, as compared to \$2.2 million and \$0.8 million, respectively, during the same period in the prior year. Interest and

other income for the three months ended March 31, 2015 was \$0.2 million as compared to a loss of \$0.2 million, during the same period in the prior year. The net impact from the U.S. dollar during the period was nil.

Windsor Locks Thermal Facility

For the three months ended March 31, 2015, the Windsor Locks Thermal Facility sold 196.3 billion lbs of steam and 28.0 GW-hrs of energy, as compared to 201.2 billion lbs of steam and 32.7 GW-hrs of energy in the comparable period of 2014.

The Windsor Locks Thermal Facility's operating profit was driven by energy/steam sales of \$7.8 million, as compared to \$10.9 million in the same period, a decrease of \$3.1 million. The decrease in energy/steam sales is primarily attributed to lower volume and lower prices realized in the merchant market. Gas costs for the period were \$5.7 million as compared to \$8.0 million in the same period in 2014, a decrease of \$2.3 million. The decrease in gas costs is a result of the decrease in the average landed cost of natural gas per MMBTU in the first quarter of 2015 in addition to lower volumes purchased due to decreased demand, as compared to the same period in 2014 which experienced below seasonal temperatures.

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, 2015, net energy/steam sales at the Windsor Locks Thermal Facility totalled \$2.1 million, as compared to \$2.9 million during the same period in 2014, a decrease of \$0.8 million primarily due to the lower percentage sales to the merchant market due to the lower demand along with a decrease in steam sales as compared to the prior year as discussed above.

Operating expenses excluding natural gas costs were \$1.3 million, which is consistent during the same period in 2014. The main items in operating expense for the period were repairs and maintenance expense and cost of RECs sold from inventory (an offset to operating expense is booked when a REC is generated and is recorded as inventory and reversed when sold) partly offset by a stronger U.S. dollar. The Windsor Locks Thermal Facility's resulting net operating income for the three months ended March 31, 2015 was \$1.1 million, as compared to \$2.2 million in the same period in 2014, a decrease of \$1.1 million.

Sanger Thermal Facility

For the three months ended March 31, 2015, the Sanger Thermal Facility sold 31.9 GW-hrs of energy, as compared to 32.0 GW-hrs of energy in the comparable period of 2014.

For the three months ended March 31, 2015, the Sanger Thermal Facility's operating profit was driven by energy/steam sales of \$2.7 million, as compared to \$3.4 million in the same period in 2014, a decrease of \$0.7 million. The decrease in energy/steam sales is primarily attributable to decreased gas prices, which is a pass through to customers, as compared to 2014. Capacity revenue remained unchanged at \$0.9 million. Gas costs for the period were \$1.5 million as compared to \$1.8 million in the same period in 2014, a decrease of \$0.3 million. The decrease in gas costs is largely due to a 27% decrease in the average cost of natural gas per MMBTU, partially offset by a stronger U.S. dollar, as compared to the same period in 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, 2015, net energy sales at the Sanger Thermal Facility totalled \$1.2 million, as compared to \$1.6 million during the same period in 2014, a decrease of \$0.4 million, caused primarily by lower off peak generation demand during the quarter.

Operating expenses excluding natural gas costs were \$1.2 million, as compared to \$1.0 million during the same period in 2014. The Sanger Thermal Facility's resulting net operating income for the three months ended March 31, 2015 was \$0.6 million, as compared to \$0.8 million in the same period in 2014, a decrease of \$0.2 million.

GENERATION BUSINESS GROUP

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 the Generation Group's existing portfolio.

The Generation Group's Development Division has successfully advanced a number of projects and has been awarded or acquired a number of PPAs. All of the projects contained in the table below meet the following criteria: a proven wind or solar resource, a signed PPA with credit worthy counterparties, and meet or exceed the Company's investment return criteria.

Project Name	Location	Size (MW)	Estimated Capital Cost (millions)	Commercial Operation	PPA Term	Production GW-hrs
Projects in Construction or Recently Completed						
Morse Wind Project ¹	Saskatchewan	23	\$ 81.9	Achieved Q2'15	20	104.0
Bakersfield I Solar Project ^{1,2}	California	20	\$ 67.9	Achieved Q2'15	20	53.3
Odell Wind Project ^{1,3}	Minnesota	200	\$ 408.9	2016	20	814.7
Val-Éo Wind Project ^{1,4,5}	Quebec	24	\$ 70.0	2016	20	66.0
Bakersfield II Solar Project ^{1,6}	California	10	\$ 34.2	2016	20	24.2
Total Projects in Construction or Recently Completed		277	\$ 662.9			1,062.2
Projects in Development						
Amherst Island Wind Project ¹	Ontario	75	\$ 272.5	2016/17	20	235.0
Chaplin Wind Project ^{1,7}	Saskatchewan	177	\$ 340.0	2017/18	25	720.0
Total Projects in Development		252	\$ 612.5			955.0
Total in Construction and Development		529	\$ 1,275.4			2,017.2

¹ PPA Signed.

² Total cost of the project is expected to be approximately \$58.5 million in U.S. dollars.

³ Total cost of the project is expected to be approximately \$322.8 million in U.S. dollars.

⁴ The Val-Éo Wind Project is being developed in two phases: Phase I of the project (24 MW) 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.

⁵ Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the Val-Éo Wind Project.

⁶ Total cost of the project is expected to be approximately \$27.0 million in U.S. dollars.

⁷ The Chaplin project is being developed in two phases: Phase I of the project, which comprises approximately 35 MW of the total project, will be erected in 2017 and Phase II of the project, which comprises the remaining approximately 142 MW, will be constructed following evaluation of the wind resource at the site, and completion of satisfactory permitting.

Projects in Construction or Recently Completed

Morse Wind Project

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

Based on the award of 25 MW under Saskatchewan's Green Options Partner Program, SaskPower has offered the Generation Group a 20 year contract for the procurement of 23 MW of wind generation to match the nameplate capacity of the proposed turbines.

Construction of the project commenced in August 2014, and the project was fully operational on April 22, 2015 with all 10 turbines completed and selling its power.

Bakersfield I Solar Project

The Bakersfield I Solar Project is a 20 MWac solar powered generating station located in Kern County, California comprised of approximately 85,000 solar panels and located on 165 acres of land. The project is expected to generate 53.3 GW-hrs of energy per year with all energy from the project being sold to a large investment grade electric utility pursuant to a 20 year agreement.

Construction of the project commenced in the second quarter of 2014 and was placed in service on December 30, 2014. Testing to ensure the plant will be ready and available for commercial operations was conducted and confirmed by the Generation Group and independent engineers prior to December 31, 2014. On April 14, 2015 the project achieved COD in accordance with provisions of the PPA. The project is expected to sell energy at market rates for approximately 45 days, post COD, prior to being eligible for full commercial rates in accordance with the terms of the PPA.

The Generation Group has entered into a partnership agreement with a third party (the "Tax Partner") pursuant to which the Tax Partner will contribute U.S. \$22.8 million to the project and in return will receive the majority of the tax attributes.

Odell Wind Project

The 200MW Odell Wind Project is located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota. The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year PPA, all energy, capacity and renewable energy credits from the project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the Midwest U.S. A Limited Notice to Proceed was issued early in the second quarter with construction commencing in the middle of May. Total costs for the project are estimated at U.S. \$322.8 million. It is anticipated that the Odell Project will qualify for U.S. federal production tax credits having satisfied the Internal Revenue Service 5% beginning of construction investment safe-harbor guidance. Accordingly, approximately 60% of the permanent project financing is expected to be funded by tax equity investors.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Company is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of operations, which is expected in early 2016.

Val-Éo Wind Project

The first 24 MW phase of the Val-Éo Wind Project is in active development.

Commission de Protection du Territoire Agricole Quebec ("CPTAQ") approval has been received for ten turbine locations, roads, and the collection system. Land option agreements have all been secured, and the process of converting these options is currently underway. Substation equipment has been ordered and the BOP Agreement is under negotiations with the selected contractor.

Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MW project adjacent to the Generation Group's 20 MW Bakersfield I Solar Project in Kern County, California. The project is expected to generate 24.2 GW-hrs of energy per year with all energy from the project being sold to a large investment grade electric utility pursuant to a 20 year agreement.

During the first quarter the CUP and MNP permitting compliance binders were submitted to the County. Interconnection drawings have been submitted to the utility and comments are expected early in the second quarter.

Projects in Development

Amherst Island Wind Project

The 75MW Amherst Island Wind Project is located on Amherst Island near the village of Stella, approximately 15 km southwest of Kingston, Ontario.

The Renewable Energy Approval ("REA") application was submitted in April 2013 and posted to the environmental registry in early January 2014 and has been undergoing technical review with a recent modification posted for public comment on March 30, 2015. Changes to the project design have been initiated to optimize construction and project performance, which will require a modification of the application documents. Once the REA is issued in final form, it may be appealed by interested parties within 15 days of its release. If the REA is appealed, the appeal process is expected to take up to 6 months. Other permitting processes are progressing according to schedule. The project has a planned construction time frame of 12 to 18 months with most of the construction expected to occur in 2016.

Chaplin Wind Project

The 177MW Chaplin Wind Project is located in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

In the first quarter of 2015, the Environmental Assessment documentation was submitted and meetings were held with the Ministry of Environment. The turbine selection has been completed and signing of the Turbine Supply Agreement is expected to take place in the second quarter.

DISTRIBUTION BUSINESS GROUP

The Distribution Group operates rate-regulated utilities providing distribution services to approximately 489,000 connections in the natural gas, electric, water and wastewater sectors. The Distribution Group's strategy is to grow its business organically and through business development activities while using prudent acquisition criteria. The Distribution Group believes that its business results are maximized by building constructive regulatory and customer relationships, and enhancing community connections.

Utility System Type (all dollar amounts in U.S. \$ millions)	March 31, 2015		March 31, 2014	
	Assets	Connections	Assets	Connections
Electricity	\$ 327.8	93,000	\$ 282.4	93,000
Natural Gas	737.2	293,000	663.9	290,000
Water and Wastewater	260.8	103,000	233.4	98,000
Total	\$ 1,325.8	489,000	\$ 1,179.7	481,000
Accumulated Deferred Income Taxes	\$ 92.5		\$ 90.8	

The Distribution Group aggregates the performance of its utility operations by utility system type – electricity, natural gas, and water and wastewater systems.

The electric distribution systems are comprised of regulated electrical distribution utility systems and serve approximately 93,000 connections in the states of California and New Hampshire.

The natural gas distribution systems are comprised of regulated natural gas distribution utility systems and serve approximately 293,000 connections located in the states of New Hampshire, Illinois, Iowa, Missouri, Georgia, and Massachusetts.

The water and wastewater distribution systems are comprised of regulated water distribution and wastewater collection utility systems and serve approximately 103,000 connections located in the states of Arkansas, Arizona, Texas, Illinois, and Missouri. The Distribution Group has entered into an agreement to acquire Park Water Company ("Park Water System") which owns and operates three regulated water utilities serving approximately 74,000 customer connections in Southern California and Western Montana.

	Three months ended March 31,		Three months ended March 31,	
	2015 U.S. \$ (millions)	2014 U.S. \$ (millions)	2015 Can \$ (millions)	2014 Can \$ (millions)
Revenue				
Utility electricity sales and distribution	\$ 56.2	\$ 52.7	\$ 69.6	\$ 58.2
Less: Cost of Sales – Electricity	(37.4)	(31.0)	(46.3)	(34.2)
Net Utility Sales - Electricity	\$ 18.8	\$ 21.7	\$ 23.3	\$ 24.0
Utility natural gas sales and distribution	174.7	178.1	216.3	196.3
Less: Cost of Sales – Natural Gas	(111.5)	(126.5)	(138.0)	(139.5)
Net Utility Sales - Natural Gas	\$ 63.2	\$ 51.6	\$ 78.3	\$ 56.8
Net Utility Sales - Water Distribution & Wastewater Treatment	13.8	13.3	17.1	14.6
Gas Transportation	10.3	10.5	12.9	11.6
Other Revenue	1.9	0.6	2.3	0.7
Net Utility Sales	\$ 108.0	\$ 97.7	\$ 133.9	\$ 107.7
Operating expenses	(45.2)	(40.0)	(56.0)	(44.2)
Other income	0.7	0.7	0.9	0.8
Distribution Group operating profit	\$ 63.5	\$ 58.4	\$ 78.8	\$ 64.3

2015 Three Month Operating Results

For the three months ended March 31, 2015, the Distribution Group reported an operating profit of U.S. \$63.5 million, as compared to U.S. \$58.4 million for the comparable period in the prior year, an increase of U.S. \$5.1 million or 8.7%. The increase is primarily due to the implementation of interim rates at the EnergyNorth Gas System, the implementation of final rates as a result of the general rate case at the Missouri and Illinois Gas Systems, increased rates at the Peach State Gas System as a result of the GRAM filing and Pipeline Replacement Program, and below seasonal temperature experienced in the New Hampshire service territory, as compared to the same period in 2014. Detailed results are discussed in the following sections. Measured in Canadian dollars, the group's operating profit was \$78.8 million, as compared to \$64.3 million for the comparable period in the prior year. In addition to the factors discussed below, operating profit measured in Canadian dollars increased by \$9.4 million due to a stronger U.S. dollar.

Electric Distribution Systems

	Three months ended March 31,	
	2015	2014
Average Active Electric Connections For The Period		
Residential	79,900	78,100
Commercial and Industrial	12,400	12,300
Total Average Active Electric Connections For The Period	92,300	90,400
Customer Usage (GW-hrs)		
Residential	166.7	170.9
Commercial and Industrial	221.3	223.6
Total Customer Usage (GW-hrs)	388.0	394.5

For the three months ended March 31, 2015, the electric distribution systems' usage totalled 388.0 GW-hrs, as compared to 394.5 GW-hrs for the same period in 2014, a decrease of 6.5 GW-hrs. The decrease in usage can be primarily attributed to decreased commercial and industrial usage in the Granite State Electric System's service territory, primarily due to severe winter weather experienced during the three months ended March 31, 2015 in the New England area, which resulted in certain commercial and industrial businesses not operating for a period in February.

For the three months ended March 31, 2015, the electric distribution systems' revenue from utility electricity sales totalled U.S. \$56.2 million, as compared to U.S. \$52.7 million during the same period in 2014, an increase of U.S. \$3.5 million, or 6.6%. For the three months ended March 31, 2015, purchased power costs for the electric distribution systems totalled U.S. \$37.4 million, as compared to U.S. \$31.0 million for the same period in 2014, an increase of U.S. \$6.4 million, or 20.6%.

The purchase of electricity by the electric distribution systems is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. For the three months ended March 31, 2015, net utility sales for the electric distribution systems were U.S. \$18.8 million, as compared to U.S. \$21.7 million for the same period in 2014, a decrease of U.S. \$2.9 million, or 13.4%. In the three months ended March 31, 2014, the Granite State Electric System recognized additional revenue of \$2.5 million representing the difference between interim rates previously granted and final rates retroactive to July 1, 2013. Additionally, Granite State Electric System distribution usage for the three months ended March 31, 2015 decreased as compared to the same period in 2014 due to severe winter weather experienced during the quarter in the New England area, which closed certain commercial and industrial businesses for a short period of time in February. Although customer usage was lower by 1.5 GW-Hrs due to the warmer than normal winter weather in the Tahoe Region, 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 are not 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.

Natural Gas Distribution Systems

Three months ended March
31,

2015 2014

Average Active Natural Gas Connections For The Period

Residential	252,400	252,100
Commercial and Industrial	27,400	26,400
Total Average Active Natural Gas Connections For The Period	279,800	278,500

Customer Usage (MMBTU)

Residential	10,056,000	10,276,000
Commercial and Industrial	6,112,600	5,871,000
Total Customer Usage (MMBTU)	16,168,600	16,147,000

For the three months ended March 31, 2015, customer usage at the natural gas distribution systems totalled 16,168,600 MMBTU, as compared to 16,147,000 MMBTU during the same period in 2014, an increase of 21,600 MMBTU, or 0.2%. The increase in natural gas usage, as compared to the same period in 2014, can be primarily attributed to increased usage in the New Hampshire service territory due to colder winter weather experienced as compared to the same period in 2014, partially offset by a decrease in usage at the Midstates and Peach State Gas Systems.

For the three months ended March 31, 2015, revenue from natural gas sales and distribution totalled U.S. \$174.7 million, as compared to U.S. \$178.1 million during the same period in 2014, a decrease of U.S. \$3.4 million, or 2%. For the three months ended March 31, 2015, natural gas purchases totalled U.S. \$111.5 million, as compared to U.S. \$126.5 million for the same period in 2014, a decrease of U.S. \$15.0 million, or 12%. The cost of natural gas is passed through to the natural gas distribution systems' customers. As a result, 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of results. For the three months ended March 31, 2015, net utility sales, excluding transportation, for the natural gas distribution systems totalled U.S. \$63.2 million, as compared to U.S. \$51.6 million during the same period in 2014, an increase of U.S. \$11.6 million, or 22%. The increase in net utility sales, excluding transportation, can be primarily attributed to the implementation of interim rates at the EnergyNorth Gas System (U.S. \$3.3 million increase from the three months ended March 31, 2014), the implementation of final rates as a result of the general rate case at the Missouri and Illinois Gas Systems, partially offset by slightly warmer weather experienced in the Midstates service territory (U.S. \$1.9 million increase

from the three months ended March 31, 2014), increased rates at the Peach State Gas System as a result of the GRAM filing and Pipeline Replacement Program (U.S. \$2.0 million increase from the three months ended March 31, 2014), the below seasonal winter weather experienced in the New Hampshire service territory, as evidenced by a 9% increase in heating degree days as compared to the same period in 2014 (U.S. \$1.9 million increase from the three months ended March 31, 2014), and the net utility sales of U.S. \$0.8 million contributed by a newly acquired service territory at the New Hampshire Gas System.

For the three months ended March 31, 2015, revenue from gas transportation sales totalled U.S. \$10.3 million, as compared to U.S. \$10.5 million during the same period in 2014, a decrease of U.S. \$0.2 million, or 2%. The Midstates Gas System contributed U.S. \$1.4 million to the total transportation revenues for the three months ended March 31, 2015, the EnergyNorth Gas System contributed U.S. \$5.2 million, the Peach State Gas System contributed U.S. \$0.7 million, and the New England Gas System contributed U.S. \$3.0 million.

Water and Wastewater Distribution Systems	Three months ended March 31,	
	2015	2014
Average Active Connections For The Period		
Wastewater connections	40,000	37,300
Water distribution connections	59,000	56,000
Total Average Active Connections For The Period	99,000	93,300
Gallons Provided		
Wastewater treated (millions of gallons)	577	546
Water sold (millions of gallons)	1,677	1,707
Total Gallons Provided	2,254	2,253

During the three months ended March 31, 2015, the water and wastewater distribution systems provided approximately 1,677 million gallons of water to its customers and treated approximately 577 million gallons of wastewater, as compared to 1,707 million gallons of water and 546 million gallons of wastewater during the same period in 2014. Total average active connections for the period increased from 93,300 in the same period in the prior year compared to 99,000 in the current period. The increase can be primarily attributed to the acquisition of the White Hall Water and Sewer System on May 30, 2014 which serves approximately 1,900 water distribution and 2,400 wastewater treatment customers.

For the three months ended March 31, 2015, revenue from wastewater treatment and water distribution totalled U.S. \$6.8 million and U.S. \$7.0 million, respectively, as compared to U.S. \$6.2 million and U.S. \$7.1 million, respectively, during the same period in 2014. The increase in total wastewater treatment and water distribution revenue was primarily due to an increase in rates at the LPSCo Water and Sewer System, effective May 1, 2014, and the acquisition of the White Hall Water and Sewer System on May 30, 2014, offset by slightly lower usage in other service territories.

Other Revenue

For the three months ended March 31, 2015, other revenue totalled U.S. \$1.9 million, as compared to U.S. \$0.6 million during the same period in 2014. The other revenue primarily consists of operations and maintenance services provided by the Peach State Gas System through the privatization contract for Fort Benning, and water heater rental service revenue in the New England Gas System territory. The year over year increase is primarily attributed to additional work performed at Fort Benning in the current year.

Operating Expenses

For the three months ended March 31, 2015, operating expenses, excluding electricity purchases, totalled U.S. \$45.2 million, as compared to U.S. \$40.0 million during the same period in 2014, an increase of U.S. \$5.2 million, or 13%. The major factors resulting in the year over year increase in the group's operating expenses are set out as follows:

Three months
ended March 31,
2015

(all dollar amounts in U.S. \$ millions)

Comparative Prior Period Operating Expenses	\$	40.0
Significant Changes:		
Increase in operating expenses at New England Gas System		1.4
Increase in operating expenses at the EnergyNorth Gas System		0.9
Increase in operating expenses at the Peach State Gas System		1.0
Acquisition of New Hampshire Gas		0.4
Acquisition of White Hall Water System		0.3
Other		1.2
Current Period Operating Expenses	\$	45.2

The increase in operating expenses at the EnergyNorth and New England Gas Systems can primarily be attributed to the below seasonal temperatures which resulted in additional labour costs. Due to the below seasonal temperatures experienced during the first quarter, operating expenses increased as a result of additional maintenance-related activities in the New England and EnergyNorth service areas, increased bad debt expense primarily due to higher revenues and average customer bill, and less capital-related work completed due to extreme winter weather conditions, which resulted in a decreased capitalization rate, as compared to the same period in 2014.

The increase in operating expenses at the Peach State Gas System can be primarily attributed to an increase of U.S. \$0.6 million in cost of sales and administrative expenses for work completed at Fort Benning, as compared to the three months ended March 31, 2014.

Recently completed acquisitions of New Hampshire Gas on January 2, 2015 and White Hall Water System on May 30, 2014 resulted in increased operating expense of U.S \$0.7 million, as compared to the similar period in 2014.

Regulatory Proceedings

The following table summarizes the major regulatory proceedings within the Distribution Group currently underway:

Utility	State	Regulatory Proceeding Type	Rate Request U.S. \$ (millions)	Current Status
Completed Rate Cases				
Peach State Gas System	Georgia	GRAM	\$3.7	Final Order issued in December 2014 approving a U.S. \$3.7 million rate increase effective February 1, 2015.
Missouri Gas System	Missouri	General Rate Case	\$7.6	Final Order issued in December 2014 approving a U.S. \$4.9 million rate increase effective January 2, 2015.
Illinois Gas System	Illinois	General Rate Case	\$5.7	Final Order issued in February 2015 approving a U.S. \$4.6 million rate increase effective February 20, 2015.
Pine Bluff Water System	Arkansas	General Rate Case	\$2.5	Final Order issued in March 2015 approving a U.S. \$1.1 million rate increase effective March 15, 2015.
Pending Rate Cases				
EnergyNorth System	New Hampshire	General Rate Case	\$16.1	Application filed in August 2014; a temporary rate increase was approved on November 21, 2014 allowing a U.S. \$7.4 million interim increase effective December 1, 2014, retroactive to November 1, 2014 upon approval of permanent rates. A final permanent rates decision is expected in Q3 2015.
CalPeco Electric System	California	General Rate Case	\$13.6	Application filed in May 2015 seeking a U.S. \$13.6 million revenue increase effective January 2016. A final permanent rate decision is expected in Q1 2016.

Completed Rate Cases

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. \$3.7 million in its annual GRAM filing with the GPSC. New rates to be effective February 1, 2015, for the period February 1, 2015, through January 31, 2016, were to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30, 2014, (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). Commission approval was received on December 2, 2014.

On February 6, 2014, the Midstates Gas System filed a rate case with the Missouri Public Service Commission ("MOPSC") seeking an increase in revenue of U.S. \$7.6 million, consisting of U.S. \$6.3 million in new, incremental revenue and U.S. \$1.3 million through the ISRS surcharge (infrastructure system replacement surcharge). The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes through April 30, 2014. The case has concluded and an Order was issued on December 3, 2014, approving a U.S. \$4.9 million revenue increase effective January 2, 2015.

On March 31, 2014, the Midstates Gas System filed a rate case with the Illinois Commerce Commission ("ICC") seeking an increase in revenue 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 has concluded and an Order was issued on February 11, 2015, approving a U.S. \$4.6 million revenue increase effective February 20, 2015.

On July 2, 2014, Pine Bluff Water System filed an application with the Arkansas Public Service Commission ("APSC") seeking an increase in revenue of U.S. \$2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. The case has concluded and an Order was issued on March 12, 2015, approving a U.S. \$1.1 million revenue increase effective March 15, 2015.

Pending Rate Cases

On August 1, 2014, the EnergyNorth Natural Gas System in New Hampshire filed an application for an increase in revenue of U.S. \$16.1 million, or approximately 9.6%. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Distribution Group ownership. Expected implementation of the new permanent rates is in the third quarter of 2015. A temporary rate increase was approved on November 21, 2014, allowing a U.S. \$7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates.

On May 1, 2015, the CalPeco Electric System filed an application with the California Public Utilities Commission ("CPUC") seeking an increase in revenue of U.S. \$13.6 million, or 17.3%, based on a test year ending December 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended December 31, 2011. The CalPeco Electric System requests the increase in its general rates to continue its focus on safety and reliability and to recover the costs of investment in and the costs associated with the ownership of infrastructure facilities and increases in operations and maintenance costs. The increase reflects a return on equity of 10.5% and a debt/equity structure of 45%/55%, resulting in an overall rate of return of 7.9%. Expected implementation of the new permanent rates is in the first quarter of 2016.

Related to the above CalPeco Electric System rate application are two other pending applications in California. The first is an Application filed with the CPUC on April 17 for the issuance of a Certificate of Public Convenience and Necessity ("CPCN") to acquire, own and operate the 40 MW Luning Solar Energy Center ("Luning Project") and the 20 MW Minden Sunrise Solar Project ("Minden Project") (collectively, the "Solar Projects") and authorize rate recovery for the costs that the CalPeco Electric System will incur to acquire, own, and operate the Solar Projects. The second is an Application filed on April 24th with the CPUC for authorization to enter into a multi-year Services Agreement with NV Energy commencing January 2016 and authority to recover the costs it will incur under the 2016 NV Energy Services Agreement as energy purchase costs. This new PPA is required as an existing PPA with NV Energy expires at the end of 2015. These two applications will allow the CalPeco Electric System to obtain its energy supply in a cost-effective manner for its customers and allow the utility to meet its Renewables Portfolio Standard ("RPS") requirements.

Acquisition Approval Applications

On September 19, 2014, the Distribution Group announced the entering into an agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility Park Water Company ("Park Water System"). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

The acquisition requires the approval of both the California Public Utilities Commission ("CPUC") and the Montana Public Service Commission ("MPSC"). An approval application was filed on November 24, 2014, with the CPUC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to acquire the two water utilities located in California owned by the Park Water Company, Park Central Basin and Apple Valley Ranchos Water. A decision on the California application is expected in the third quarter of 2015. An approval application was also filed on December 15, 2014, with the MPSC seeking approval for APUC, through its wholly owned subsidiary Liberty Utilities Co., to effectively acquire Mountain Water Company. A decision on the application is expected late in 2015 or early 2016.

TRANSMISSION BUSINESS GROUP

In November 2014, the Transmission Group announced an agreement to participate in a natural gas pipeline transmission project in partnership with Kinder Morgan, Inc. ("Northeast Expansion LLC") to undertake the development, construction and ownership of a 30-inch or 36-inch natural gas transmission pipeline to be located between Wright, NY and Dracut, MA (the "Project"). The Transmission Group will initially subscribe for a 2.5% interest in Northeast Expansion LLC. APUC also has an opportunity to increase its participation up to 10%. The total capital investment opportunity for APUC could be up to U.S. \$400 million, depending on the final pipeline configuration and design capacity.

The project is in the early phases of permitting and development. On March 13, 2015, the first draft of the Environmental Review was filed with FERC. This Environmental Review provides an update to FERC on environmental considerations related to the proposed route. Construction is expected to begin in January 2017 and commercial operations by November 1, 2018.

APUC: CORPORATE AND OTHER EXPENSES

(all dollar amounts in \$ millions)	Three months ended March 31,	
	2015	2014
Corporate and other expenses:		
Administrative expenses	\$ 10.4	\$ 7.7
(Gain)/Loss on foreign exchange	(1.2)	(1.8)
Interest expense	16.6	16.2
Interest, dividend and other Income ¹	(0.5)	(1.2)
Write down of long lived assets	(0.1)	0.4
Acquisition-related costs	0.3	0.3
(Gain)/Loss on derivative financial instruments	(0.1)	(0.4)
Income tax expense	19.4	11.9

¹ Excludes income directly pertaining to the Generation and Distribution Groups (disclosed in the relevant sections).

2015 First Quarter Corporate and Other Expenses

During the three months ended March 31, 2015, administrative expenses totalled \$10.4 million, as compared to \$7.7 million in the same period in 2014. The increase primarily relates to additional costs incurred to administer APUC's operations as a result of the company's growth.

For the three months ended March 31, 2015, interest expense totalled \$16.6 million, as compared to \$16.2 million in the same period in 2014. The increased interest expense is a result of new indebtedness incurred midway in the first quarter of 2014 whereby the full quarter of interest expense has been recorded in 2015.

For the three months ended March 31, 2015, interest, dividend and other income totalled \$0.5 million, as compared to \$1.2 million in the same period in 2014, a decrease of \$0.7 million due to no dividends received from Kirkland and Cochrane investments in 2015.

For the three months ended March 31, 2015, acquisition-related costs totalled \$0.3 million which was consistent with the same period in 2014. Acquisition-related costs will vary from period to period depending on the level of activity and complexity associated with various acquisitions.

An income tax expense of \$19.4 million was recorded in the three months ended March 31, 2015, as compared to an income tax expense of \$11.9 million during the same period in 2014. The increase in income tax expense for the three months ended March 31, 2015, is primarily due to increased earnings from operations, increased deferred taxes on HLBV income, a stronger U.S. dollar, 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 unaudited interim Consolidated Statement of Operations. This supplementary disclosure is intended to more fully explain disclosures related to Adjusted EBITDA and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to GAAP consolidated net earnings.

(all dollar amounts in \$ millions)	Three months ended March 31,	
	2015	2014
Net earnings attributable to Shareholders	\$ 43.1	\$ 35.9
Add (deduct):		
Net earnings attributable to the non-controlling interest, exclusive of HLBV	0.6	3.8
Income from discontinued operations	—	(0.3)
Income tax expense	19.4	11.9
Interest expense	16.6	16.2
Loss / (Gain) on sale of assets	(1.1)	—
Non-cash write downs	(0.1)	0.4
Acquisition costs	0.3	0.3
(Gain) / Loss on derivative financial instruments	(0.1)	(0.4)
Realized gain / (loss) on energy derivative contracts	0.6	4.0
(Gain) / Loss on foreign exchange	(1.2)	(1.8)
Depreciation and amortization	36.4	28.3
Adjusted EBITDA	\$ 114.5	\$ 98.3

Hypothetical Liquidation at Book Value (“HLBV”) represents the value of net tax attributes earned by the Generation Group 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, 2015 and 2014, amounted to approximately \$8.9 million and \$8.5 million, respectively.

For the quarter ended March 31, 2015, Adjusted EBITDA totalled \$114.5 million, as compared to \$98.3 million during the same period in 2014, an increase of \$16.2 million.

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

(all dollar amounts in \$ millions)		Three months ended March 31
Comparative Prior Period Adjusted EBITDA	\$	98.3
Significant Changes:		
Favorable settlements on periodic production shortfalls under the power hedges at the Minonk, Senate and Sandy Ridge Wind Facilities and higher pricing realized on sales of the unhedged portion of energy produced, partially offset by lower production at all of the facilities other than Sandy Ridge		0.7
Start of commercial operations of the St. Damase Wind Facility		1.8
Higher realized prices on sale of Renewable Energy Credits at the U.S. Wind Facilities partially offset by decrease in sales of Renewable Energy Credits at the Windsor Locks Thermal Facility		1.3
First full quarter of commercial operations for the Cornwall Solar Facility		1.0
Decreased customer load and retail pricing in the Maritime region		(1.6)
Lower realized prices at the Sanger and Windsor Locks Thermal Facilities combined with lower production		(1.0)
Increase due to implementation of interim rates at EnergyNorth Gas System and the implementation of general rate increases at the Missouri Gas System, the Illinois Gas system, Peach State Gas System, and the LPSCO Water system		7.0
Decrease at the Granite State Gas System due to \$1.6 million of additional revenue recognized in the first quarter of 2014 pertaining to the difference in the interim rates and final rates recognized as part of the last rate case.		(1.6)
Increased revenues at Peach State Gas System's Fort Benning operations		1.3
Increase in administrative expense		(2.7)
Increased results from the stronger U.S. dollar		11.5
Other		(1.5)
Current Period Adjusted EBITDA	\$	114.5

Reconciliation of adjusted net earnings to net earnings

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

The following table shows the reconciliation of net earnings to adjusted net earnings exclusive of these items:

(all dollar amounts in \$ millions)		Three months ended March 31,	
		2015	2014
Net earnings attributable to Shareholders	\$	43.1	\$ 35.9
Add (deduct):			
(Gain) / Loss from discontinued operations, net of tax		—	(0.3)
(Gain) / Loss on derivative financial instruments, net of tax		—	(0.2)
Realized gain / (loss) on derivative financial instruments, net of tax		—	2.0
Write down long lived assets		(0.1)	0.4
(Gain) / Loss on foreign exchange, net of tax		(0.7)	(1.1)
Acquisition costs, net of tax		0.2	0.2
Adjusted net earnings	\$	42.5	\$ 36.9
Adjusted net earnings per share	\$	0.17	\$ 0.17

For the three months ended March 31, 2015, adjusted net earnings totalled \$42.5 million, as compared to adjusted net earnings of \$36.9 million, an increase of \$5.6 million as compared to the same period in 2014. The increase in adjusted net earnings for the three months ended March 31, 2015, is primarily due to higher income from operations partially offset by higher interest expense, and depreciation and amortization expense as compared to the same period in 2014.

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 unaudited interim Consolidated Statement of Operations and Statement of Cash Flows. This supplementary disclosure is intended to more fully explain disclosures related to adjusted funds from operations and provides additional information related to the operating performance of APUC. Investors are cautioned that this measure should not be construed as an alternative to funds from operations in accordance with GAAP.

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

(all dollar amounts in \$ millions)	Three months ended March 31,	
	2015	2014
Cash flows from operating activities	\$ (7.4)	\$ 14.8
Add (deduct):		
Changes in non-cash operating items	97.3	58.4
Cash (provided)/used in discontinued operation	—	0.2
Production based cash contributions from non-controlling interests	10.8	9.0
Acquisition costs	0.3	0.3
Adjusted funds from operations	\$ 101.0	\$ 82.7
Adjusted funds from operations per share	\$ 0.41	\$ 0.39

For the three months ended March 31, 2015, adjusted funds from operations totalled \$101.0 million, as compared to adjusted funds from operations of \$82.7 million, an increase of \$18.3 million as compared to the same period in 2014.

SUMMARY OF PROPERTY, PLANT, AND EQUIPMENT EXPENDITURES

(all dollar amounts in \$ millions)	Three months ended March 31,	
	2015	2014
GENERATION GROUP		
Renewable	\$ 20.2	\$ 11.2
Thermal	0.2	1.4
Total Generation Business Group	\$ 20.4	\$ 12.6
DISTRIBUTION GROUP	\$ 23.5	\$ 19.5
Corporate	1.5	44.7
Total	\$ 45.4	\$ 76.8

The company's consolidated capital expenditure plan for 2015 is approximately \$275.0 million. The Generation Group expects to invest approximately \$107.0 million primarily in connection with its development portfolio. The Distribution Group expects to invest approximately \$161.0 million (U.S. \$127.0 million) primarily to improve the reliability and efficiency of its gas and electric utility distribution systems. The Transmission Group expects to invest approximately \$7.0 million (U.S. \$5.8 million) for the natural gas pipeline transmission project.

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

2015 Three Month Property Plant and Equipment Expenditures

During the three months ended March 31, 2015, the Generation Group incurred capital expenditures of \$20.4 million, as compared to \$12.6 million during the comparable period in 2014.

During the three months ended March 31, 2015, the Generation Group's Renewable Energy Division spent \$20.2 million in capital expenditures, as compared to \$11.2 million in the comparable period in 2014. The capital expenditures primarily relate to the completion of the Bakersfield Solar and Morse Wind Projects, and the construction of the Bakersfield II Solar project. The Generation Group's Thermal Energy Division net capital expenditures were \$0.2 million, as compared to \$1.4 million in the comparable period in 2014.

During the three months ended March 31, 2015, the Distribution Group invested \$23.5 million (U.S. \$19.0 million) in capital expenditures, as compared to \$19.5 million (U.S. \$17.7 million) during the comparable period in 2014. The Distribution Group's capital expenditures primarily related to a compressed natural gas project, a new training center, improvements to buildings in the New Hampshire service territory, leak prone pipe replacements, leak repairs, pipeline corrosion protection systems and interconnect pressure reduction station renewals.

Quebec Dam Safety Act

As a result of the dam safety legislation passed in Quebec (Bill C-93), the Generation Group 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.

The Generation Group currently estimates further capital expenditures of approximately \$7.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

(all dollar amounts in \$ millions)	Total	2015	2016	2017	2018
Future Estimated Bill C-93 Capital Expenditures	\$ 7.9	1.0	3.1	3.5	0.3

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

The Generation Group has been working with the provincial authorities to reclassify, decommission or remove several small dams upstream of the Bellettre Hydro Facility that are not required for power generation. During the first quarter, four dams have been declassified and removed from the CEHQ's registry, while three others have been reclassified to Class E (Very Low Consequence) dams, from higher classes. Upon the recommendation of third party engineers, the Generation Group has requested a postponement of the decommissioning work on these dams for five years to allow sufficient time to determine the new decommissioning requirements and develop new project plans.

LIQUIDITY AND CAPITAL RESERVES

APUC has revolving operating facilities available for APUC, the Generation Group and the Distribution Group 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 operating groups as at March 31, 2015, under the Facilities:

(all dollar amounts in \$ millions)	As at March 31, 2015				As at Dec 31 2014	
	Corporate	Generation Group	Distribution Group	Total	Total	
Committed Facilities	\$ 65.0	\$ 350.0	\$ 253.3	\$ 668.3	\$ 647.0	
Funds drawn on Facilities	—	(93.6)	(102.6)	(196.2)	(47.3)	
Letters of Credit issued	(11.8)	(107.3)	(10.0)	(129.1)	(113.8)	
Funds available for draws on the Facilities	\$ 53.2	\$ 149.1	\$ 140.7	\$ 343.0	\$ 485.9	
Cash on Hand				22.6	9.3	
Total liquidity and capital reserves	\$ 53.2	\$ 149.1	\$ 140.7	\$ 365.6	\$ 495.2	

As at March 31, 2015, the Company's \$65.0 million senior unsecured revolving credit facility (the "Corporate Credit Facility"), was undrawn and had \$11.8 million of outstanding letters of credit. The facility matures on November 19, 2016, and is subject to customary covenants.

As at March 31, 2015, the Generation Group's \$350.0 million Credit Facility ("Generation Credit Facility") had drawn \$93.6 million and had \$107.3 million in outstanding letters of credit.

As at March 31, 2015, the Distribution Group's \$253.3 million (U.S. \$200.0 million) senior unsecured revolving credit facility (the "Distribution Credit Facility") had drawn \$102.6 million (U.S. \$81.0 million) and had \$10.0 million (U.S. \$7.9 million) of outstanding letters of credit. The facility matures on September 30, 2018, and is subject to customary covenants.

Long Term Debt

Subsequent to quarter end, on April 30, 2015, the Distribution Group issued U.S. \$160.0 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing will be used to partially finance the acquisition of the Park Water System and for general corporate purposes. The funds are being drawn in two tranches: U.S. \$90 million was drawn immediately on closing and U.S. \$70 million will be drawn in the third quarter. The financing is the fourth series of notes issued pursuant to the company's master indenture.

As at March 31, 2015, the weighted average tenor of APUC's total long term debt is approximately 8.0 years with an average interest rate of 4.9%.

Contractual Obligations

Information concerning contractual obligations as of March 31, 2015, is shown below:

(all dollar amounts in \$ millions)	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
Long-term debt obligations	\$ 1,493.4	9.9	99.1	379.0	1,005.4
Advances in aid of construction	\$ 88.6	1.3	—	—	87.3
Interest on long-term debt obligations	\$ 462.4	71.3	138.6	106.0	146.5
Purchase obligations	\$ 188.7	188.7	—	—	—
Environmental obligation	\$ 79.3	20.9	42.0	5.4	11.0
Derivative financial instruments:					
Cross currency swap	\$ 65.1	3.0	5.5	4.6	52.0
Interest rate forward	\$ 9.3	—	—	9.3	—
Interest rate swap	\$ 1.0	1.0	—	—	—
Energy derivative contracts	\$ 1.6	1.6	—	—	—
Purchased power	\$ 63.7	63.7	—	—	—
Gas delivery, service and supply agreements	\$ 290.7	61.8	73.2	62.6	93.1
Long term service agreements	\$ 678.6	32.2	68.8	66.6	511.0
Capital projects	\$ 7.6	7.6	—	—	—
Operating leases	\$ 128.2	6.2	10.1	9.0	102.9
Other obligations	\$ 44.7	10.7	0.9	—	33.1
Total obligations	\$ 3,602.9	\$ 479.9	\$ 438.2	\$ 642.5	\$ 2,042.3

Equity

The common shares of APUC are publicly traded on the Toronto Stock Exchange (“TSX”). As at March 31, 2015, APUC had 238,882,611 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, 2015, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A preferred shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon Wind Energy LP; and
- 4,000,000 cumulative rate reset Series D preferred 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 holders of shares of APUC. As at March 31, 2015, 51.0 million common shares representing approximately 21% of total shares outstanding had been registered with the Reinvestment Plan. During the quarter ended March 31, 2015, 706,680 common shares were issued under the Reinvestment Plan, and subsequent to the end of the quarter, on April 15, 2015, an additional 619,468 common shares were issued under the Reinvestment Plan.

Emera shareholdings and subscription receipts

As at May 8, 2015, in total, Emera owns 50,126,766 APUC common shares representing approximately 21.0% of the total outstanding common shares of the Company, and 12,024,753 subscription receipts. 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, 2015, APUC recorded \$0.9 million in total share-based compensation expense, as compared to \$0.4 million for the same period in 2014. No tax deduction was realized in the current year. The compensation expense is recorded as part of administrative expenses in the unaudited interim Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at March 31, 2015, total unrecognized compensation costs related to non-vested options and share unit awards were \$1.5 million and are expected to be recognized over a period of 1.5 years.

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.

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.

As at March 31, 2015, a total of 5,537,127 options had been granted and outstanding under the plan.

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.

The plan provides for settlement in cash or shares at the election of the Company. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Company expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards.

As at March 31, 2015, a total of 439,489 PSU's had 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, 2015, a total of 120,636 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, 2015, a total of 266,874 shares had been issued under the ESPP.

RELATED PARTY TRANSACTIONS

A member of the Board of Directors of APUC is an executive at Emera. For the three months ended March 31, 2015, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S. \$1,637 (2014 - U.S. \$4,018). For the three months ended March 31, 2015, Liberty Utilities purchased natural gas amounting to U.S. \$123 (2014 - U.S. \$2,977) 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 to these transactions at the end of the periods.

As at March 31, 2015, \$nil (December 31, 2014 - \$47) was due from Algonquin Power Systems Ltd., a corporation partially owned by Ian Robertson and Chris Jarratt (collectively "Senior Executives").

Chartered Aircraft

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into a block time agreement to charter aircraft in which Senior Executives have a partial ownership. During the quarter, the Company provided notice of early termination of the agreement effective June 28, 2015 and expects the usage shortfall fee, if any, to be no higher than \$25. During the three months period ended March 31, 2015, APUC reimbursed direct costs in connection with the use of the aircraft of \$189 (2014 - \$215).

Office Facilities

APUC had leased its head office facilities from an entity partially owned by Senior Executives. In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease. Base lease costs for the three months ended March 31, 2015 were \$nil (2014 - \$79).

Other

A spouse of one of the Senior Executives was employed to provide market research services to certain subsidiaries of the Company. During the three months ended March 31, 2015 APUC paid \$20 (2014 - \$46) in relation to these services. The spouse is no longer employed by the Company.

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled by the end of 2015.

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

ENTERPRISE RISK MANAGEMENT

An enterprise risk management ("ERM") framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. APUC's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization. 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.

Treasury Risk Management

Market Price Risk

The Distribution Business Group is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

The Generation Group has certain market price risk exposures and takes steps to mitigate those risks.

On May 15, 2012, the Generation Group 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 the facility's expected production volume against exposure to the Alberta Power Pool's current spot market rates. The annual unhedged production based on long term projected averages is approximately 16,000 MW-hrs annually. Therefore, each U.S. \$10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of U.S. \$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 expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. \$10 per MW-hr change in the market prices would result in a change in revenue of about U.S. \$0.4 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 the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. \$10 per MW-hr change in the market prices would result in a change in revenue of about U.S. \$1.9 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 expected

production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. \$10 per MW-hr change in market prices would result in a change in revenue of about U.S. \$1.9 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.

In addition to the above noted hedges, from time to time the Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at March 31, 2015, the Generation Group had not entered into any such hedges.

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 U.S. \$10 per MW-hr change in market prices would result in a change in revenue of about U.S. \$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 Corporate Credit Facility is subject to a variable interest rate. The APUC Facility has no amounts outstanding as at March 31, 2015. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The Generation Credit Facility had \$93.6 million outstanding as at March 31, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$0.9 million annually.
- The Distribution Credit Facility had \$102.6 million outstanding as at March 31, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$1.0 million annually.
- The Generation Group is party to an interest rate swap whereby the group pays a fixed interest rate of 4.47% on a notional amount of \$60.5 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. 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. As a result, a 100 basis point change in the variable rate would impact derivative gains/losses by \$0.01 million.
- The Shady Oaks Senior Debt Facility had \$96.3 million (U.S. \$76.0 million) outstanding as at March 31, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by \$1.0 million (U.S. \$0.8 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. The interest rate swap, although not designated as a hedge, serves to partially offset interest rate movements against the variable pay portion of the Company's debt.

To mitigate refinancing risk, from time to time APUC may seek to fix interest rates on expected future financings. The Generation Group has entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its \$135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded into Other Comprehensive Income.

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 the Generation Group and the Distribution Group 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 to meet liabilities when due.

As at March 31, 2015, APUC and its subsidiaries had a combined \$343 million of committed and available revolving credit facilities remaining and \$22.6 million of cash resulting in \$365.6 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. \$0.35 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 current and long term portion of debt totals approximately \$1,493.4 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.

OPERATIONAL RISK MANAGEMENT

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. The following are material updates to the annual MD&A for the year ended December 31, 2014.

Trafalgar Proceedings

Trafalgar commenced an action in 1999 in U.S. District Court against various Algonquin entities in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to the Algonquin entities 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"). Over the past 16 years there have been various legal proceedings and appeals in connection with this matter. Currently both the Algonquin entities and Trafalgar have certain motions before the Bankruptcy Court seeking determinations on a number of matters. Those motions are under consideration by the Bankruptcy Court.

The Bankruptcy Court has approved the sale of all seven of the Trafalgar Hydro Facilities. Of the seven, three have closed while the other three are anticipated to close in May 2015. The Forestport hydroelectric facility is scheduled to close upon obtaining regulatory approval. The parties are attempting to resolve this matter through good faith settlement 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. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011, onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court's judgment of March 12, 2015.

Dimos and Katsekas Breach of Contract Claim

On September 30, 2013, Dimos and Katsekas, previous owners of the Clement Dam Hydroelectric, LLC. ("Clement Dam Hydro Facility"), filed a demand for arbitration with Algonquin Power Fund (America) Inc. ("APFA") 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 May, 2015.

Arbitration hearings are scheduled for May 11-13, 2015, and May 19-22, 2015. At present, the litigation has been stayed pending the outcome of the arbitration proceeding.

Tax Risk and Uncertainty

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

Unit Exchange Transaction

On October 27, 2009, unitholders of Algonquin Power Income Fund exchanged their trust units on a one for one basis for common shares of Algonquin Power & Utilities Corp (the “Unit Exchange Transaction”). As a result of the Unit Exchange Transaction, APUC recorded certain additional tax attributes to the extent management believed they were more likely than not to be realized. The excess of the carrying amount of the tax attributes assumed over the consideration paid was recorded as a deferred credit of \$55.6 million on the date of the Unit Exchange Transaction (the “Transaction Date”). The deferred credit has been recognized into income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that have been utilized since the Transaction Date.

During the quarter, APUC received a proposal letter from the Canada Revenue Agency (“CRA”) which outlines its intention to challenge the tax consequences of APUC’s 2009 Unit Exchange. CRA is seeking to apply the acquisition of control rules or the general anti-avoidance rules of the Income Tax Act (Canada), the effect of which would be to deny APUC of the benefit of the tax attributes assumed as part of the Unit Exchange Transaction.

Should APUC receive a Notice of Reassessment covering the 2009, 2010, 2011, 2012 and 2013 taxation years, APUC will be required to make a deposit payment of 50% of the tax liability (including interest and any applicable penalties) claimed by the CRA in order to appeal the expected reassessment. Based on the tax amounts related to the 2009 to 2013 taxation years, that payment amount would be approximately \$17.5 million. Additionally, assuming the 2014 taxation year will be similarly reassessed, a further payment of approximately \$3.1 million would also be required. APUC would also be required to make a deposit payment of 50% of the taxes the CRA claims are owed in any future tax year if the CRA were to issue a similar notice of reassessment for such years and APUC were to appeal it.

Should APUC be successful in defending its position, all such payments plus applicable interest will be refunded to APUC. If the CRA is successful, APUC will be required to pay the balance of the taxes assessed (plus applicable interest and any applicable penalties).

APUC has 90 days from the date of any Notice of Reassessment to prepare and file a Notice of Objection, which would be reviewed by the CRA’s appeals division. If the CRA appeals division does not allow APUC’s initial appeal, APUC has the option to file its case with the Tax Court of Canada. APUC anticipates that legal proceedings through the various tax courts could take approximately two to four years.

APUC remains confident in the appropriateness of its tax filing position and the expected tax consequences of the Unit Exchange Transaction and intends to vigorously defend such position. APUC strongly believes that the acquisition of control or the general anti-avoidance rules do not apply to the Unit Exchange Transaction and intends to file its future tax returns on a basis consistent with its previous tax returns. As a result, the probability of any potential final cash payment and impact on net earnings cannot be estimated at this time, but could range from \$nil to \$45.0 million.

The impact of the proposal on APUC’s tax provision has been considered by management; however, management continues to believe that the most likely outcome has not changed, and it is more likely than not that APUC will be successful in defending its position. On this basis, APUC’s 2014 financial statements do not include the impact of a potential reassessment. Until the matter is resolved with CRA, or should new facts arise that would result in a change to management’s assessment of the most likely outcome, any future deposit tax payments made by APUC will be recorded to the balance sheet and will not impact either adjusted funds from operations or net earnings.

On a consolidated basis, APUC and its Canadian subsidiaries have tax attributes that are available to reduce or eliminate cash taxes. Should the CRA ultimately be successful in the appeal process, APUC will seek to refile prior year tax returns and accelerate the use of such tax attributes to minimize any actual cash taxes that would otherwise be owed as a result of the reassessment of the tax consequences of the Unit Exchange.

QUARTERLY FINANCIAL INFORMATION

The following is a summary of unaudited quarterly financial information for the eight quarter ended March 31, 2015:

(all dollar amounts in \$ millions except per share information)	2nd Quarter 2014	3rd Quarter 2014	4th Quarter 2014	1st Quarter 2015
Revenue	\$ 189.3	\$ 151.9	\$ 259.3	\$ 381.9
Adjusted EBITDA	66.4	41.4	84.3	114.5
Net earnings / (loss) attributable to shareholders from continuing operations	15.3	(6.1)	33.1	43.1
Net earnings / (loss) attributable to shareholders	14.6	(6.3)	31.6	43.1
Net earnings / (loss) per share from continuing operations	0.06	(0.04)	0.13	0.16
Net earnings / (loss) per share	0.06	(0.04)	0.13	0.16
Adjusted net earnings	16.5	(0.4)	35.2	42.5
Adjust net earnings per share	0.07	(0.01)	0.14	0.17
Total Assets	3,561.9	3,808.5	4,113.7	4,531.4
Long term debt ¹	1,389.3	1,413.5	1,280.0	1,482.7
Dividend declared per common share	0.09	0.10	0.10	0.11
	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	40.2	68.5	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	13.2	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	18.8	36.8
Adjust net earnings per share	0.08	0.03	0.08	0.17
Total Assets	3,201.8	3,156.4	3,476.5	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

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.

Quarterly revenues have fluctuated between \$127.9 million and \$381.9 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 \$43.1 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

As of March 31, 2015, APUC carried out an evaluation, under the supervision of and with the participation of APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of APUC's disclosure controls and procedures (as defined in Rule 13a – 15(e) and Rule 15d – 15 (e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")). Based on that evaluation, the CEO and the CFO have concluded that as of March 31, 2015, APUC's disclosure controls and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, including the CEO and the CFO, is responsible for establishing and maintaining internal control over financial reporting. Management, as at the end of the period covered by this interim filing, designed internal control over financial reporting to provide reasonable, but not absolute, assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. The control framework management used to design the issuer's internal control over financial reporting is that established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

During the quarter ended March 31, 2015, 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.

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.

Except for adopted accounting policy described below, the significant accounting policies and estimates applied to the unaudited interim consolidated financial statements of APUC for the three months period ended March 31, 2015 are consistent with those disclosed in APUC's MD&A and Note 1 of its consolidated financial statements for the year ended December 31, 2014, available on SEDAR.

Effective January 1, 2015, the Company applied ASU 2015-03, Interest: Imputation of Interest (Subtopic 835-30) retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs that were previously presented as Other Assets on the Consolidated Balance Sheets have been reclassified as a deduction from the carrying amount of the related long-term liabilities.

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	March 31, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 22,643	\$ 9,273
Accounts receivable, net (note 4)	244,313	188,573
Natural gas in storage	9,244	31,550
Supplies and consumables inventory	12,609	11,825
Regulatory assets (note 5)	39,713	61,645
Prepaid expenses	20,163	10,431
Notes receivable (note 6)	494	2,966
Deferred income taxes (note 15)	17,471	7,210
Income taxes receivable (note 15)	593	568
Derivative instruments (note 20)	10,653	10,688
	377,896	334,729
Property, plant and equipment, net	3,543,987	3,278,422
Intangible assets, net	72,119	54,011
Goodwill	100,803	92,328
Regulatory assets (note 5)	194,750	186,669
Derivative instruments (note 20)	51,176	31,782
Long-term investments (note 6)	109,400	43,279
Deferred income taxes (note 15)	56,336	57,065
Other assets	24,926	24,368
	\$ 4,531,393	\$ 4,102,653

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Balance Sheets

(thousands of Canadian dollars)

	March 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 21,416	\$ 68,540
Accrued liabilities	167,255	199,374
Dividends payable (note 12)	29,140	25,395
Regulatory liabilities (note 5)	29,264	20,590
Long-term liabilities (note 7)	9,869	9,130
Pension and other post-employment benefits (note 8)	364	333
Other long-term liabilities (note 9)	50,742	49,303
Derivative instruments (note 20)	5,549	5,183
Preferred shares, Series C	1,077	1,085
Income taxes liability (note 15)	1,973	3,633
Deferred income taxes (note 15)	405	3,702
	317,054	386,268
Long-term liabilities (note 7)	1,472,825	1,260,161
Regulatory liabilities (note 5)	109,533	101,166
Deferred income taxes (note 15)	176,346	130,758
Derivative instruments (note 20)	71,395	40,088
Pension and other post-employment benefits (note 8)	153,208	138,602
Other long-term liabilities (note 9)	194,170	179,468
Preferred shares, Series C	17,569	17,608
	2,195,046	1,867,851
Redeemable non-controlling interest (note 3(c))	12,172	12,146
Equity:		
Preferred shares	213,805	213,805
Common shares (note 10(a))	1,639,899	1,633,262
Subscription receipts	110,503	110,503
Additional paid-in capital	33,960	33,068
Deficit	(492,659)	(505,305)
Accumulated other comprehensive income (note 11)	152,640	34,213
Total equity attributable to shareholders of Algonquin Power & Utilities Corp.	1,658,148	1,519,546
Non-controlling interests	348,973	316,842
Total equity	2,007,121	1,836,388
Commitments and contingencies (note 18)		
Subsequent events (note 7)		
	\$ 4,531,393	\$ 4,102,653

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,	
	2015	2014
Revenue		
Regulated electricity distribution	\$ 69,589	\$ 58,164
Regulated gas distribution	229,212	207,863
Regulated water reclamation and distribution	17,079	14,641
Non-regulated energy sales	57,712	57,920
Other revenue	8,262	4,449
	381,854	343,037
Expenses		
Operating	71,160	57,744
Regulated electricity purchased	46,259	34,180
Regulated gas purchased	138,032	139,467
Non-regulated energy purchased	13,423	20,259
Administrative expenses	10,447	7,727
Depreciation of property, plant and equipment	33,056	26,895
Amortization of intangible assets	1,213	1,079
Other amortization	2,118	350
Gain on foreign exchange	(1,243)	(1,756)
	314,465	285,945
Operating income from continuing operations	67,389	57,092
Interest expense	16,633	16,199
Interest, dividend, equity-investment and other income	(2,455)	(2,194)
Other gains	(1,098)	—
Acquisition-related costs	299	273
Write-down on long-lived assets	(105)	376
Gain on derivative financial instruments (note 20(b)(iv))	(97)	(363)
	13,177	14,291
Earnings from continuing operations before income taxes	54,212	42,801
Income tax expense (note 15)		
Current	1,636	1,143
Deferred	17,755	10,727
	19,391	11,870
Earnings from continuing operations	34,821	30,931
Income from discontinued operations, net of tax	—	273
Net earnings	34,821	31,204
Net loss attributable to non-controlling interests (note 14)	(8,285)	(4,648)
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	\$ 43,106	\$ 35,852
Basic net earnings per share from continuing operations (note 16)	\$ 0.16	\$ 0.16
Basic net earnings per share (note 16)	0.16	0.17
Diluted net earnings per share from continuing operations (note 16)	0.16	0.16
Diluted net earnings per share (note 16)	\$ 0.16	\$ 0.16

See accompanying notes to unaudited interim consolidated financial statements

Algonquin Power & Utilities Corp.

Unaudited Interim Consolidated Statements of Comprehensive Income

(thousands of Canadian dollars)

	Three months ended March 31,	
	2015	2014
Net earnings	\$ 34,821	\$ 31,204
Other comprehensive income:		
Foreign currency translation adjustment, net of tax expense of \$Nil and \$40, respectively (note 20(b)(iii))	141,192	47,404
Change in fair value of cash flow hedge, net of tax expense of \$5,095 and tax recovery of \$3,868, respectively (note 20(b)(ii))	6,444	(11,924)
Change in unrealized appreciation in value of available-for-sale investments	(47)	—
Change in pension and other post-employment benefits, net of tax recovery of \$256 and tax expense of \$207, respectively (note 8)	(54)	(450)
Other comprehensive income, net of tax	147,535	35,030
Comprehensive income	182,356	66,234
Comprehensive income attributable to the non-controlling interests	20,823	9,542
Comprehensive income attributable to shareholders of Algonquin Power & Utilities Corp.	\$ 161,533	\$ 56,692

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, 2015

Algonquin Power & Utilities Corp. Shareholders

	Common shares	Preferred shares	Subscription receipts	Additional paid-in capital	Accumulated deficit	Accumulated OCI	Non- controlling interests	Total
Balance, December 31, 2014	\$1,633,262	\$213,805	\$ 110,503	\$ 33,068	\$ (505,305)	\$ 34,213	\$316,842	\$1,836,388
Net earnings (loss)	—	—	—	—	43,106	—	(8,285)	34,821
Redeemable non- controlling interests not included in equity	—	—	—	—	—	—	1,106	1,106
Other comprehensive income	—	—	—	—	—	118,427	29,108	147,535
Dividends declared and distributions to non-controlling interests	—	—	—	—	(23,777)	—	(613)	(24,390)
Dividends and issuance of shares under dividend reinvestment plan	6,683	—	—	—	(6,683)	—	—	—
Contributions received from non-controlling interests	—	—	—	—	—	—	10,815	10,815
Shares issued pursuant to public offering, net of costs	(294)	—	—	—	—	—	—	(294)
Issuance of common shares under employee share purchase plan	248	—	—	—	—	—	—	248
Share-based compensation	—	—	—	892	—	—	—	892
Balance, March 31, 2015	\$1,639,899	\$213,805	\$ 110,503	\$ 33,960	\$ (492,659)	\$ 152,640	\$348,973	\$2,007,121

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,
2015 2014

Cash provided by (used in):			
Operating Activities			
Net earnings from continuing operations	\$	34,821	\$ 30,931
Adjustments and items not affecting cash:			
Depreciation of property, plant and equipment		33,056	26,895
Amortization of intangible assets		1,213	1,079
Other amortization		1,602	391
Deferred taxes		17,755	10,727
Unrealized loss (gain) on derivative financial instruments		96	3,113
Share-based compensation		892	341
Cost of equity funds used for construction purposes		(550)	(516)
Pension and post-employment expense		1,108	(236)
Deferred insurance proceeds and revenue amortization		(744)	—
Write-down of long-lived assets		366	698
Unrealized gain on disposal of VIE investment		220	—
Changes in non-cash operating items (note 19)		(97,262)	(58,203)
Changes in non-cash operating items from discontinued operations		—	(193)
Cash used in discontinued operations		—	(192)
		(7,427)	14,835
Financing Activities			
Cash dividends on common shares		(17,432)	(13,875)
Cash dividends on preferred shares		(2,600)	(1,350)
Cash contributions from non-controlling interests		22	—
Production based cash contributions from non-controlling interest		10,815	8,976
Cash distributions to non-controlling interests		(613)	(2,967)
Issuance of common shares, net of costs		(46)	156
Issuance of preferred shares, net of costs		—	96,533
Increase in long-term liabilities		137,330	415,641
Decrease in long-term liabilities		(609)	(293,786)
Increase in other long-term liabilities		2,208	572
Decrease in other long-term liabilities		(1,662)	(1,309)
		127,413	208,591
Investing Activities			
Increase (decrease) in other assets		242	(1,404)
Distributions received in excess of equity income		(21)	143
Receipt of principal on notes receivable		2,530	77
Additions to property, plant and equipment		(45,401)	(76,898)
Acquisitions of long-term investments		(61,324)	—
Acquisitions of operating entities		(3,388)	(648)
Acquisition of non-controlling interest		—	(127,260)
		(107,362)	(205,990)
Effect of exchange rate differences on cash		746	459
Increase in cash and cash equivalents		13,370	17,895
Cash and cash equivalents, beginning of the period		9,273	13,839
Cash and cash equivalents, end of the period	\$	22,643	\$ 31,734
Supplemental disclosure of cash flow information:		2015	2014
Cash paid during the year for interest expense	\$	25,647	\$ 18,969
Cash paid during the year for income taxes	\$	464	\$ 88
Non-cash transactions: Property, plant and equipment acquisitions in accruals	\$	18,262	\$ 13,213

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 is a diversified generation, transmission and distribution utility company. The distribution business group operates in the United States under the name of Liberty Utilities Co. ("Distribution Group") and provides rate regulated water, electricity and natural gas utility services. The generation business group operates under the name Algonquin Power Co. ("Generation Group") and owns or has interests in a portfolio of non-regulated North American based contracted wind, solar, hydroelectric and natural gas powered generating facilities. The transmission business group operates under the name Liberty Utilities (Pipeline & Transmission) ("Transmission Group") and invests in rate regulated electric transmission and natural gas pipeline systems in the United States and Canada.

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, 2014 except for adopted accounting policies described in note 2(a).

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. Where decoupling mechanisms exist, total volumetric revenue is prescribed by the Regulator and fluctuates based on usage while total fixed revenue will not fluctuate through the year. 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 2015-03, Interest: Imputation of Interest (Subtopic 835-30), to simplify presentation of debt issuance costs. The amendments in this ASU require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected. Effective January 1, 2015, the Company applied this ASU retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs of \$10,732 as of December 31, 2014 that were previously presented as Other assets on the consolidated balance sheets have been reclassified as a deduction from the carrying amount of the related long-term liabilities.

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. Effective January 1, 2015, the Company adopted this ASU prospectively and as a result, its adoption had no impact on discontinued operations reported in prior periods.

2. Recently issued accounting pronouncements (continued)**(b) Recent accounting guidance not yet adopted**

The FASB issued ASU 2015-05, Intangibles: Goodwill and Other Internal-Use Software (Subtopic 350-40), to provide guidance to customers about whether a cloud computing arrangement includes a software license. This ASU can be adopted either (1) prospectively to all arrangements entered into or materially modified after the effective date or (2) retrospectively. The standard is effective for fiscal years and interim periods beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-04, Compensation: Retirement Benefits (Subtopic 715), to provide a practical expedient that permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This ASU should be applied prospectively. The standard is effective for fiscal years and interim periods beginning after December 15, 2015. Early adoption of the amendments in this ASU is permitted. The Company's fiscal year-end coincide with a month-end, therefore, other than for future significant events that would call for remeasurement, the adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis, which ends the deferral granted to investment companies from applying the VIE guidance and makes targeted amendments to the current consolidation guidance. Some of the more notable amendments are (1) the identification of variable interests when fees are paid to a decision maker or service provider, (2) the VIE characteristics for a limited partnership or similar entity and (3) the primary beneficiary determination. This ASU may be applied using a modified retrospective approach by recording a cumulative-effect adjustment to equity as of the beginning of the fiscal year of adoption or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2015-01, Income Statement: Extraordinary and Unusual Items (Subtopic 225-20), to simplify income statement classification by removing the concept of extraordinary items from U.S. GAAP. As a result, items that are both unusual and infrequent will no longer be separately reported net of tax after continuing operations. This ASU may be applied prospectively or retrospectively to all prior periods presented in the financial statements. The standard is effective for periods beginning after December 15, 2015. Early adoption is permitted, but only as of the beginning of the fiscal year of adoption. The adoption of this standard is not expected to have an impact on the Company's results of operations.

The FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815): Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity. ASU No. 2014-16 clarifies how current guidance should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. In addition, ASU 2014-16 clarifies that in evaluating the nature of a host contract, an entity should assess the substance of the relevant terms and features (that is, the relative strength of the debt-like or equity-like terms and features given the facts and circumstances) when considering how to weigh those terms and features. The effects of initially adopting ASU 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in a form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. ASU 2014-16 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The Company is currently in the process of evaluating the impact of adoption of this standard on its consolidated financial statements.

The FASB issued ASU 2014-15, Presentation of Financial Statements — Going Concern. This new standard provides that in connection with preparing financial statements for each annual and interim reporting period, an entity's management should evaluate whether there are conditions or events, that raise substantial doubt about the entity's ability to continue as a going concern within one year after the date that the financial statements are issued. This ASU will be effective for the annual reporting period ending after December 15, 2016, and for annual and interim periods thereafter. Early application is permitted. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

2. Recently issued accounting pronouncements (continued)**(b) Recent accounting guidance not yet adopted (continued)**

The FASB issued ASU 2014-12, Compensation-Stock Compensation (Topic 718): Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period. This newly issued accounting standard is intended to resolve the diverse accounting treatment of those awards in practice. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2015. The adoption of this standard is not expected to have an impact on the Company's financial position or results of operations.

The FASB and the International Accounting Standards Board have jointly issued a new revenue recognition standard codified in U.S. GAAP as ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This newly issued accounting standard provides accounting guidance for all revenue arising from contracts with customers and affects all entities that enter into contracts to provide goods or services to their customers unless the contracts are in the scope of other U.S. GAAP requirements, such as the leasing literature. This ASU is required to be applied for fiscal years and interim periods beginning after December 15, 2016 using either a full retrospective approach for all periods presented in the period of adoption or a modified retrospective approach. The Company is currently assessing the impact the adoption of this standard might have on its financial position or results of operations.

3. Business acquisitions and development projects**(a) Acquisition of New Hampshire Gas**

On January 2, 2015, the Distribution Group completed the acquisition of New Hampshire Gas, a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System is approximately U.S. \$3,047, subject to certain closing adjustments.

(b) Agreement to acquire Park Water System

On September 19, 2014, the Company entered into an agreement to acquire the regulated water distribution utility Park Water Company ("Park Water System"). Park Water System owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Total consideration for the utility purchase is expected to be approximately U.S. \$327,000, which includes the assumption of approximately U.S. \$77,000 of existing long-term utility debt and is subject to certain working capital and other closing adjustments. Closing of the transaction is subject to certain conditions including state and federal regulatory approval, and is expected to occur in late 2015 or early 2016.

(c) Development of Bakersfield Solar Facility

The Company constructed a 20 MWac solar powered generating facility located in Kern County, California. The Company invested U.S. \$57,294 in the development and construction of the solar energy facility which is recorded as property, plant and equipment. The facility was placed in service on December 31, 2014 and is selling renewable power at merchant rates. The facility achieved commercial operation under the power purchase agreement on April 14, 2015 and is expected to sell power at the power purchase agreement price in the second quarter of 2015. The weighted average useful life of the Bakersfield Solar Facility is 35 years.

On August 13, 2014, the Generation Group entered into a partnership agreement with a third-party (the "Tax Investor"). It is anticipated that approximately U.S. \$22,800 will be funded by the Tax Investor. With its partnership interest, the Tax Investor will receive the majority of the tax attributes associated with the facility. The Tax Equity investment net of non-controlling interest earned as of March 31, 2015 is U.S. \$9,610.

Under certain conditions, the Tax Investor has the right to withdraw from the Bakersfield Solar Facility and require the Company to redeem its interests for cash over a contractual payment period. As a result, the Company accounts for this interest as temporary equity outside of permanent equity on the consolidated balance sheets as "Redeemable non-controlling interest".

3. Business acquisitions and development projects (continued)

(c) Development of Bakersfield Solar Facility (continued)

At each balance sheet date, the Company will reevaluate the classification of its redeemable instrument, as well as the probability of redemption. If the redemption amount is probable or currently redeemable, the Company will record the instruments at its redemption value. Increases or decreases in the carrying amount of a redeemable instrument will be recorded within accumulated deficit. Redemption is not considered probable as of March 31, 2015.

(d) Commercial operation of Morse Wind Facility

The Company constructed a 23 MW wind generating facility located near Morse, Saskatchewan. The Company invested \$64,919 in the development and construction of the wind facility 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 \$81,875. Sale of power to the utility commenced in March 2015 at rates equivalent to those under the power purchase agreement. Commercial operations date as defined in the power purchase agreement occurred on April 22, 2015. The weighted average useful life of the Morse Wind Facility is 32 years.

4. Accounts receivable

Accounts receivable as of March 31, 2015 include unbilled revenue of \$43,985 (December 31, 2014 - \$52,880) from the Company's regulated utilities. Accounts receivable as of December 31, 2014 are presented net of allowance for doubtful accounts of \$10,469 (December 31, 2014 - \$7,229).

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 FASB ASC 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, the Company can have several regulatory proceedings underway. The financial effects of these proceedings are reflected in the consolidated financial statements based on regulatory approval obtained to the extent that there is a financial impact during the applicable reporting period.

On February 11, 2015, the Midstates Gas System received a Final Order from the Illinois Commerce Commission approving an annual revenue increase of U.S. \$4,625 in connection with its rate application filing on March 31, 2014. The new rates are effective as of February 20, 2015.

On March 12, 2015, the Pine Bluff System received a Final Order from the Arkansas Public Service Commission approving an annual revenue increase of U.S. \$1,087. The new rates are effective as of March 15, 2015.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***5. Regulatory matters (continued)**

Regulatory assets and liabilities consist of the following:

	March 31, 2015	December 31, 2014
Regulatory assets		
Environmental costs	\$ 107,373	\$ 102,735
Pension and post-employment benefits	70,390	65,745
Storm costs	1,244	2,050
Commodity costs adjustment	20,457	41,502
Rate case costs	4,418	4,161
Vegetation management	3,226	3,260
Debt premium	5,018	4,658
Rate adjustment mechanism	6,572	6,207
Asset retirement obligation	1,857	1,682
Tax related	5,111	4,350
Other	8,797	11,964
Total regulatory assets	\$ 234,463	\$ 248,314
Less current regulatory assets	(39,713)	(61,645)
Non-current regulatory assets	\$ 194,750	\$ 186,669
Regulatory liabilities		
Cost of removal	\$ 85,562	\$ 78,013
Rate-base offset	24,766	23,427
Commodity costs adjustment	17,066	10,389
Depreciation adjustment mechanism	3,618	3,518
Other	7,785	6,409
Total regulatory liabilities	\$ 138,797	\$ 121,756
Less current regulatory liabilities	(29,264)	(20,590)
Non-current regulatory liabilities	\$ 109,533	\$ 101,166

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***6. Long-term investments**

Long-term investments consist of the following:

	March 31, 2015	December 31, 2014
Equity-method investees		
50% interest in Odell Wind Project	\$ 2,475	\$ 2,267
2.5% interest in natural gas pipeline development	2,148	1,063
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	1,512	1,512
50% interest in the Valley Power Partnership	1,274	1,253
Other	549	503
Total	\$ 7,958	\$ 6,598
Available-for-sale investment	\$ 1,398	\$ 137
Notes receivable		
Development loan (a)	\$ 78,424	\$ 17,582
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%	494	649
Silverleaf resorts loan, interest at 15.48% maturing July 2020	2,559	2,344
Other	908	782
	100,538	39,510
Less current portion	(494)	(2,966)
Total	\$ 100,044	\$ 36,544
Total long-term investments	\$ 109,400	\$ 43,279

(a) Odell Wind Project

During the quarter, the Company loaned an additional U.S. \$48,758 to Odell SponsorCo for development costs of the Odell Wind Project. Interest revenue of U.S. \$307 was accrued during the quarter. The Company also issued a U.S. \$ 1,119 letter of credit on behalf of the Odell Wind Project pursuant to the generator interconnection agreement.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***7. Long-term liabilities**

Long-term liabilities consist of the following:

	March 31, 2015	December 31, 2014
Generation Group		
\$350,000 Revolving unsecured credit facility	\$ 92,220	\$ 22,084
\$485,000 Algonquin Power Co.- Senior unsecured notes	481,574	481,438
U.S. \$90,651 Shady Oaks Wind Facility - Senior debt	96,262	88,168
\$35,757 Long Sault Hydro Facility - Senior debt	35,825	35,997
\$2,924 Chuteford Hydro Facility - Senior debt	2,917	3,022
Distribution Group		
U.S. \$200,000 Revolving unsecured credit facility	101,793	23,111
U.S. \$365,000 Liberty Utilities Co. - Senior unsecured notes	458,652	419,876
U.S. \$70,000 Calpeco Electric System - Senior unsecured notes	87,777	80,368
U.S. \$50,000 Liberty Water Co - Senior unsecured notes	62,584	57,301
U.S. \$19,500 New England Gas System - First mortgage bonds	29,726	27,288
U.S. \$15,000 Granite State Electric System - Senior unsecured notes	18,969	17,373
U.S. \$10,579 LPSCo Water System - IDA bonds	13,400	12,441
U.S. \$948 Bella Vista Water System - Loans	1,200	1,149
Deferred financing costs on undrawn revolving credit facilities	(205)	(325)
	\$ 1,482,694	\$ 1,269,291
Less current portion	(9,869)	(9,130)
	\$ 1,472,825	\$ 1,260,161

Effective January 1, 2015, the Company applied ASU 2015-03 (note 2(a)) retrospectively to all prior periods presented in the financial statements. As a result, deferred financing costs of \$10,732 as of December 31, 2014 that were previously presented as Other assets on the consolidated balance sheets have been reclassified as a deduction from the carrying amount of the related long-term liabilities in the table above.

Subsequent to quarter end, on April 30, 2015, the Distribution Group issued U.S. \$160,000 of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing will be used in connection with the acquisition of the Park Water System and for general corporate purposes. The funds are being drawn in two tranches: U.S. \$90,000 was drawn immediately on closing and U.S. \$70,000 will be drawn in the third quarter.

8. Pension and other post-employment benefits

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

Pension benefits		
Three months ended March 31,		
	2015	2014
Service cost	\$ 1,625	\$ 1,298
Interest cost	2,282	2,044
Expected return on plan assets	(2,840)	(2,479)
Amortization of net actuarial loss (gain)	298	(85)
Amortization of prior service costs	(32)	—
Amortization of net regulatory assets/liabilities	1,247	498
Net benefit cost	\$ 2,580	\$ 1,276

OPEB		
Three months ended March 31,		
	2015	2014
Service cost	\$ 720	\$ 527
Interest cost	662	541
Expected return on plan assets	(189)	(158)
Amortization of net actuarial loss (gain)	33	(158)
Amortization of net regulatory assets/liabilities	293	43
Net benefit cost	\$ 1,519	\$ 795

On February 6, 2015, the Board of Directors approved a resolution to permanently freeze the accrual of retirement benefits for most non-union participants under existing plans, effective March 31, 2015. Subsequent to the effective date, these employees will begin accruing benefits under the Company's cash balance plan. The plan amendment resulted in a decrease to the projected benefit obligation of U.S. \$2,750 which is recorded as a prior service credit in other comprehensive income ("OCI"). In conjunction with the plan amendment, the assets and projected benefit obligations of amended plans were revalued as at February 6, 2015 which resulted in an actuarial loss of U.S. \$3,246 recorded in OCI.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***9. Other long-term liabilities**

Other long-term liabilities consist of the following:

	March 31, 2015	December 31, 2014
Advances in aid of construction	\$ 88,541	\$ 81,104
Environmental obligation	78,760	72,305
Deferred tax credit (note 15)	17,923	19,130
Deferred insurance proceeds	11,092	12,191
Asset retirement obligation	15,211	13,884
Other	33,385	30,157
	244,912	228,771
Less current portion	(50,742)	(49,303)
	\$ 194,170	\$ 179,468

10. Shareholders' capital

(a) Common shares

Number of common shares:

	2015
Common shares, beginning of year	238,149,468
Issuance of shares under the dividend reinvestment and employee share purchase plans	733,143
Common shares, end of period	238,882,611

(b) Share-based compensation

During the three months ended March 31, 2015, 10,395 Deferred Share Units ("DSU") were issued pursuant to the election of the Directors to defer a percentage of their Directors' fee in the form of DSUs.

For the three months period ended March 31, 2015, APUC recorded \$872 (2014 - \$420) 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 of March 31, 2015, total unrecognized compensation costs related to non-vested options and performance share unit were \$1,543 and \$1,972, respectively, and are expected to be recognized over a period of 1.49 years and 1.39, respectively.

11. Accumulated other comprehensive income (loss)

Accumulated other comprehensive income (loss) consists of the following balances, net of tax:

	Foreign currency cumulative translation	Unrealized gain (loss) on cash flow hedges	Net change on available- for-sale investments	Pension and post- employment actuarial changes	Total
Balance, January 1, 2014	\$ (57,471)	\$ 11,840	\$ —	\$ 14,221	\$ (31,410)
OCI before reclassifications	68,938	3,358	519	(35,396)	37,419
Amounts reclassified	—	5,423	(518)	(273)	4,632
Net current period OCI (loss)	68,938	8,781	1	(35,669)	42,051
Acquisition of non-controlling interest	21,029	2,543	—	—	23,572
Balance, December 31, 2014	\$ 32,496	\$ 23,164	\$ 1	\$ (21,448)	\$ 34,213
OCI (loss) before reclassifications	112,084	6,829	(47)	(353)	118,513
Amounts reclassified	—	(385)	—	299	(86)
Net current period OCI (loss)	112,084	6,444	(47)	(54)	118,427
Balance, March 31, 2015	\$ 144,580	\$ 29,608	\$ (46)	\$ (21,502)	\$ 152,640

Amounts reclassified from accumulated other comprehensive income (loss) ("AOCI") for unrealized gain (loss) on cash flow hedges affected revenue from non-regulated energy sales while those for pension and post-employment actuarial changes affected administrative expenses.

12. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board. For the three months ended March 31, 2015, the Company declared dividends to shareholders on common shares totaling \$27,807 (2014 - \$17,584). The Board declared a dividend on the Company's common shares of U.S. \$0.0875 or \$0.1108 per share payable on April 15, 2015 to the shareholders of record on March 31, 2015.

For the three months ended March 31, 2015, the Company declared and paid dividends to Series A preferred shareholders totaling \$1,350 (2014 - \$1,350) or \$0.2813 per Series A preferred share (2014 - \$0.2813 per Series A preferred share).

For the three months ended March 31, 2015, the Company declared and paid dividends to Series D preferred shareholders totaling \$1,250 (2014 - \$Nil) or \$0.3125 per Series D preferred share (2014 - \$Nil per Series D preferred share).

13. Related party transactions

A member of the Board of Directors of APUC is an executive at Emera. For the three months ended March 31, 2015, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S. \$1,637 (2014 - U.S. \$4,018). For the three months ended March 31, 2015, Liberty Utilities purchased natural gas amounting to U.S. \$123 (2014 - U.S. \$2,977) 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 to these transactions at the end of the periods.

As at March 31, 2015, \$nil (December 31, 2014 - \$47) was due from Algonquin Power Systems Ltd., a corporation partially owned by Ian Robertson and Chris Jarratt (collectively "Senior Executives").

13. Related party transactions (continued)*Chartered Aircraft*

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into a block time agreement to charter aircraft in which Senior Executives have a partial ownership. During the quarter, the Company provided notice of early termination of the agreement effective June 28, 2015 and expects the usage shortfall fee, if any, to be no higher than \$25. During the three months period ended March 31, 2015, APUC reimbursed direct costs in connection with the use of the aircraft of \$189 (2014 - \$215).

Office Facilities

APUC had leased its head office facilities from an entity partially owned by Senior Executives. In the fourth quarter of 2014, APUC moved all head office employees into new premises and terminated the related party lease. Base lease costs for the three months ended March 31, 2015 were \$nil (2014 - \$79).

Other

A spouse of one of the Senior Executives was employed to provide market research services to certain subsidiaries of the Company. During the three months ended March 31, 2015 APUC paid \$20 (2014 - \$46) in relation to these services. The spouse is no longer employed by the Company.

Effective December 31, 2013, APUC acquired the shares of Algonquin Power Corporation Inc. ("APC") which was partially owned by Senior Executives. APC owns the partnership interest in the 18MW Long Sault Hydro Facility. A final post-closing adjustment related to the transaction is expected to be settled by the end of 2015.

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 loss attributable to non-controlling interests for the three months ended March 31 consists of the following:

	2015	2014
Net earnings attributable to Class B partnership units of Wind Portfolio SponsorCo	\$ —	\$ 3,483
Net loss attributable to Class A partnership units	(8,862)	(8,490)
Other net earnings attributable to non-controlling interests	577	359
Total net loss attributable to non-controlling interests	\$ (8,285)	\$ (4,648)

On March 31, 2014, the Company acquired the remaining Class B partnership units of Wind Portfolio SponsorCo from the non-controlling interest holder. As a result of the transaction, the Company now owns 100% of Wind Portfolio SponsorCo's Class B partnership units.

15. Income taxes

For the three months ended March 31, 2015, the Company's overall effective tax rate was different than the statutory rate of 26.50% (2014 - 26.50%) due primarily to higher tax rates in U.S. subsidiaries, non-controlling interest partner's tax expenses, recognition of deferred credits, inter-corporate dividends, and non-deductible expenses.

Included in deferred income tax expense for the three months ended March 31, 2015 is \$1,207 (2014 - \$3,377) 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 and subscription receipts outstanding. Diluted net earnings per share is computed using the weighted-average number of common shares and subscription receipts; additional shares issued subsequent to the balance sheet date under the dividend reinvestment plan; PSUs and DSUs outstanding during the period; and, if dilutive, potential incremental common shares issuable upon the exercise of stock options. The dilutive effect of outstanding stock options is reflected in diluted earnings per share by application of the treasury stock method.

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

	2015	2014
Net earnings attributable to shareholders of APUC	\$ 43,106	\$ 35,852
Series A Preferred shares dividend	1,350	1,350
Series D Preferred shares dividend	1,250	353
Net earnings attributable to common shareholders of APUC	\$ 40,506	\$ 34,149
Discontinued operations	—	273
Net earnings attributable to common shareholders of APUC from continuing operations - Basic and Diluted	\$ 40,506	\$ 33,876
Weighted average number of shares and subscription receipts		
Basic	250,776,336	206,777,996
Effect of dilutive securities	3,114,464	1,737,787
Diluted	253,890,800	208,515,783

The shares potentially issuable as a result of Nil stock options (2014 – 816,402) are excluded from this calculation as they are anti-dilutive.

17. Segmented information

The Company's management reporting is aligned under three business units - Generation, Transmission and Distribution. Under Generation, the Company owns or has interests in hydroelectric, solar and wind power facilities which are aggregated as the renewable segment and operates co-generation, steam production and other thermal facilities which are aggregated as the thermal segment. The Distribution reporting segment aggregates the electric, natural gas and water distribution utilities into a single reporting segment. Finally, the Transmission reporting segment, invests in rate regulated electric transmission and natural gas pipeline systems. As a result, APUC has four reporting segments.

The operating segments were aggregated as generation (renewable, thermal), distribution and transmission based on their economic characteristics. The Transmission segment includes the new equity method investment in the Natural Gas Pipeline Development which is not yet significant and as a result is not presented separately in the tables below.

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 derivative 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 reflected in the tables below.

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

(in thousands of Canadian dollars, except as noted and per share amounts)

17. Segmented information (continued)

	Three months ended March 31, 2015					
	Renewable	Generation Thermal	Total	Distribution	Corporate	Total
Revenue						
Regulated electricity distribution	\$ —	\$ —	\$ —	\$ 69,589	\$ —	\$ 69,589
Regulated gas distribution	—	—	—	229,212	—	229,212
Regulated water reclamation and distribution	—	—	—	17,079	—	17,079
Non-regulated energy sales	47,234	10,478	57,712	—	—	57,712
Other revenue	5,003	937	5,940	2,322	—	8,262
Total revenue	52,237	11,415	63,652	318,202	—	381,854
Operating expenses	12,586	2,521	15,107	56,038	15	71,160
Regulated electricity purchased	—	—	—	46,259	—	46,259
Regulated gas purchased	—	—	—	138,032	—	138,032
Non-regulated energy purchased	6,215	7,208	13,423	—	—	13,423
	33,436	1,686	35,122	77,873	(15)	112,980
Administrative expenses	4,280	106	4,386	6,406	(345)	10,447
Depreciation of property, plant and equipment	14,214	1,677	15,891	16,654	511	33,056
Amortization of intangible assets	769	250	1,019	194	—	1,213
Other amortization	(20)	—	(20)	2,138	—	2,118
Gain on foreign exchange	—	—	—	—	(1,243)	(1,243)
Interest expense	8,295	330	8,625	7,546	462	16,633
Interest, dividend, equity-investment and other income	(847)	(190)	(1,037)	(926)	(492)	(2,455)
Other gains	(1,098)	—	(1,098)	—	—	(1,098)
Acquisition-related costs	—	—	—	—	299	299
Write-down of long-lived assets	(370)	(8)	(378)	273	—	(105)
(Gain)/ loss on derivative financial instruments	(193)	—	(193)	—	96	(97)
Earnings (loss) from continuing operations before income taxes	8,406	(479)	7,927	45,588	697	54,212
Property, plant and equipment	\$1,703,386	\$ 91,319	\$1,794,705	\$1,688,538	\$ 60,744	\$ 3,543,987
Equity-method investees	2,475	1,274	3,749	2,693	1,516	7,958
Total assets	2,012,223	110,572	2,122,795	2,297,458	111,140	4,531,393
Capital expenditures	20,173	224	20,397	23,540	1,464	45,401

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

(in thousands of Canadian dollars, except as noted and per share amounts)

17. Segmented information (continued)

	Three months ended March 31, 2014					
	Generation			Distribution	Corporate	Total
	Renewable	Thermal	Total			
Revenue						
Regulated electricity distribution	\$ —	\$ —	\$ —	\$ 58,164	\$ —	\$ 58,164
Regulated gas distribution	—	—	—	207,863	—	207,863
Regulated water reclamation and distribution	—	—	—	14,641	—	14,641
Non-regulated energy sales	43,581	14,339	57,920	—	—	57,920
Other revenue	3,001	765	3,766	683	—	4,449
Total revenue	46,582	15,104	61,686	281,351	—	343,037
Operating expenses	11,176	2,316	13,492	44,237	15	57,744
Regulated electricity purchased	—	—	—	34,180	—	34,180
Regulated gas purchased	—	—	—	139,467	—	139,467
Non-regulated energy purchased	10,423	9,836	20,259	—	—	20,259
	24,983	2,952	27,935	63,467	(15)	91,387
Administrative expenses	3,303	85	3,388	3,959	380	7,727
Depreciation of property, plant and equipment	11,862	1,461	13,323	13,274	298	26,895
Amortization of intangible assets	663	229	892	187	—	1,079
Other amortization	—	—	—	350	—	350
Gain on foreign exchange	—	—	—	—	(1,756)	(1,756)
Interest expense	8,189	381	8,570	7,051	578	16,199
Interest, dividend, equity-investment and other income	(388)	183	(205)	(823)	(1,166)	(2,194)
Acquisition-related costs	—	—	—	—	273	273
Write-down of long-lived assets	—	376	376	—	—	376
(Gain)/loss on derivative financial instruments	(2,098)	—	(2,098)	—	1,735	(363)
Earnings (loss) from continuing operations before income taxes	3,452	237	3,689	39,469	(357)	42,801
(Income) loss from discontinued operations before income taxes	384	(322)	62	—	—	62
Earnings (loss) before income taxes	\$ 3,068	\$ 559	\$ 3,627	\$ 39,469	\$ (357)	\$ 42,739
Capital expenditures	11,247	1,434	12,681	19,539	44,678	76,898
December 31, 2014						
Property, plant and equipment	\$1,602,465	\$ 85,000	\$1,687,465	\$1,531,166	\$ 59,791	\$3,278,422
Equity-method investees	2,267	1,253	3,520	1,563	1,515	6,598
Total assets	1,795,568	100,603	1,896,171	2,099,690	106,792	4,102,653

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 Quebec Court of Appeal ordered a subsidiary of APUC to pay approximately \$5,400 (including interest) to the Government of Quebec 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 \$6,400. In 2012, the Company paid an amount of \$1,884 to the government of Quebec 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.

(b) Commitments

In addition to the commitments related to the proposed acquisitions and development projects disclosed in notes 3 and 6, the following significant commitments exist as of March 31, 2015.

As a result of the dam safety legislation passed in Quebec (Bill C-93), 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 \$7,900 over a period of five years related to compliance with the legislation.

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	\$ 63,764	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 63,764
Gas delivery, service and supply agreements	61,767	39,611	33,541	32,304	30,286	93,105	290,614
Service agreements	32,239	34,743	34,062	33,256	33,322	511,009	678,631
Capital projects	7,628	—	—	—	—	—	7,628
Operating leases	6,165	5,247	4,842	4,507	4,449	102,921	128,131
Total	\$171,563	\$ 79,601	\$72,445	\$70,067	\$68,057	\$707,035	\$1,168,768

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***19. Non-cash operating items**

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

	Three months ended March 31,	
	2015	2014
Accounts receivable	\$ (55,055)	\$ (44,449)
Natural gas in storage	22,306	19,170
Supplies and consumable inventory	(558)	(775)
Income taxes receivable	(25)	(11)
Prepaid expenses	(9,580)	(70)
Accounts payable	(47,265)	(320)
Accrued liabilities	(43,354)	(10,312)
Current income tax liability	(1,660)	1,107
Net regulatory assets and liabilities	37,929	(22,543)
	\$ (97,262)	\$ (58,203)

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***20. Financial instruments**

(a) Fair value of financial instruments

March 31, 2015	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	\$ 100,538	\$ 102,646	\$ —	\$ 102,646	\$ —
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	61,781	61,781	—	—	61,781
Energy contracts not designated as a cash flow hedge	47	47	—	—	47
Total derivative financial instruments	61,828	61,828	—	—	61,828
Total financial assets	\$ 162,366	\$ 164,474	\$ —	\$ 102,646	\$ 61,828
Long-term liabilities	\$ 1,482,694	\$ 1,606,187	\$ 529,012	\$ 1,077,175	\$ —
Preferred shares, Series C	18,646	18,846	—	18,846	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	65,072	65,072	—	65,072	—
Interest rate swap designated as a hedge	9,293	9,293	—	9,293	—
Interest rate swaps not designated as a hedge	1,026	1,026	—	1,026	—
Commodity contracts for regulated operations	1,553	1,553	—	1,553	—
Total derivative financial instruments	76,944	76,944	—	76,944	—
Total financial liabilities	\$ 1,578,284	\$ 1,701,977	\$ 529,012	\$ 1,172,965	\$ —

Algonquin Power & Utilities Corp.

Notes to the Unaudited Interim Consolidated Financial Statements

Three months ended March 31, 2015 and 2014

*(in thousands of Canadian dollars, except as noted and per share amounts)***20. Financial instruments (continued)**

(a) Fair value of financial instruments (continued)

December 31, 2014	Carrying amount	Fair Value	Level 1	Level 2	Level 3
Notes receivable	\$ 39,510	\$ 41,339	\$ —	\$ 41,339	
Derivative financial instruments:					
Energy contracts designated as a cash flow hedge	41,966	41,966	—	—	41,966
Energy contracts not designated as a cash flow hedge	504	504	—	—	504
Total derivative financial instruments	42,470	42,470	—	—	42,470
Total financial assets	\$ 81,980	\$ 83,809	\$ —	\$ 41,339	\$ 42,470
Long-term liabilities	\$1,269,291	\$1,363,934	\$ 520,142	\$ 843,792	\$ —
Preferred shares, Series C	18,693	18,209	—	18,209	—
Derivative financial instruments:					
Cross-currency swap designated as a net investment hedge	36,276	36,276	—	36,276	—
Interest rate swaps designated as a hedge	4,684	4,684	—	4,684	—
Interest rate swaps not designated as a hedge	1,383	1,383	—	1,383	—
Commodity contracts for regulated operations	2,928	2,928	—	2,928	—
Total derivative financial instruments	45,271	45,271	—	45,271	—
Total financial liabilities	\$1,333,255	\$1,427,414	\$ 520,142	\$ 907,272	\$ —

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 as of March 31, 2015 and December 31, 2014 due to the short-term maturity of these instruments.

Notes receivable fair values (level 2) 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.

The Company's level 2 fair value of long-term liabilities at fixed interest rates and Series C preferred shares has been determined using a discounted cash flow method and 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 9.0%. 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 2015 or 2014.

The Company's level 3 instruments consist of energy contracts for electricity sales. The significant unobservable inputs used in the fair value measurement of energy contracts are the internally developed forward market prices ranging from \$19.00 to \$104.71 with a weighted average of \$40.65 as of March 31, 2015. 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 fair value recognized on derivative instruments executed with the same counterparty under a master netting arrangement are presented on a gross basis on the consolidated balance sheets. The amounts that could net settle are not significant.

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, 2015 or 2014.

(b) Derivative instruments and hedging relationships

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

(i) Commodity derivatives – regulated accounting

The Company uses derivative financial instruments to reduce the cash flow variability associated with the purchase price for a portion of future natural gas purchases associated with its regulated gas service territories. The Company's strategy is to minimize fluctuations in gas sales prices to regulated customers.

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

	2015
Financial contracts: Gas swaps	995,745
Gas options	224,940
	1,220,685

20. Financial instruments (continued)

(b) Derivative instruments and hedging relationships (continued)

(i) Commodity derivatives – regulated accounting (continued)

The accounting for these derivative instruments is subject to 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 consolidated balance sheets. Gains or losses on the settlement of these contracts are included in the calculation of deferred gas costs (note 5). As a result, the changes in fair value of these natural gas derivative contracts and their offsetting adjustment to regulatory assets and liabilities had no earnings impact. The following table presents the impact of the change in the fair value of the Company's natural gas derivative contracts had on the consolidated balance sheets:

	March 31, 2015	December 31, 2014
Regulatory assets:		
Gas swap contracts	U.S. \$ 1,133	U.S. \$ 2,178
Gas option contracts	U.S. \$ 93	U.S. \$ 346
Regulatory liabilities:		
Gas swap contracts	U.S. \$ —	U.S. \$ —
Gas option contracts	U.S. \$ —	U.S. \$ —

(ii) Cash flow hedges

The Company 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)
89,028	December 2016	\$ 68.00	AESO
877,743	December 2022	U.S. \$ 42.81	PJM Western HUB
3,760,979	December 2022	U.S. \$ 30.25	NI HUB
4,219,476	December 2027	U.S. \$ 36.46	ERCOT North HUB

As of March 31, 2015, an amount receivable under the derivatives for Sandy Ridge, Senate and Minonk Wind Facilities of \$536 (December 31, 2014 - \$156) was held as collateral by the counterparty.

On November 14, 2014, the Company entered into a 10-year forward-starting interest rate swap beginning on July 25, 2018 in order to reduce the interest rate risk related to the probable issuance on that date of a 10-year \$135,000 bond. The change in fair value resulted in a loss of \$4,609 for the three months ended March 31, 2015 (2014 - \$Nil), which is recorded in OCI.

20. Financial instruments (continued)

(b) Derivative instruments and hedging relationships (continued)

(ii) Cash flow hedges (continued)

The following table summarizes changes in OCI attributable to derivative financial instruments designated as a cash flow hedge net of tax:

	Three months ended March 31,	
	2015	2014
Effective portion of cash flow hedge, gain (loss)	\$ 6,838	\$ (16,027)
Amortization on cash flow hedge	(9)	(8)
Gain (loss) reclassified from AOCI into non-regulated energy sales	(385)	4,111
	\$ 6,444	\$ (11,924)
Less non-controlling interest	—	5,982
Change in OCI attributable to shareholders of APUC	\$ 6,444	\$ (5,942)

The Company expects \$10,549 of unrealized gains currently in AOCI to be reclassified into non-regulated energy sales within the next twelve months, as the underlying hedged transactions settle.

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

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 and a combination of foreign exchange forward contracts and spot purchases. 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.

The Company designates the amounts drawn on the Generation Group's revolving credit facility denominated in U.S. dollars in excess of the principal amount on the USD loan receivable from Odell Wind SponsorCo as a hedge of the foreign currency exposure of its net investment in the Generation Group's U.S. operations. The foreign currency transaction gain or loss on the outstanding U.S. dollar denominated balance of the facility that is designated as a hedge of the net investment in its foreign operations is reported in the same manner as a translation adjustment (in OCI) related to the net investment, to the extent it is effective as a hedge. A foreign currency loss of Nil for the three months ended March 31, 2015 (2014- \$1,128) was recorded in OCI.

Concurrent with its \$150,000 and \$200,000 debenture offerings in December 2012 and January 2014, respectively, the Company entered into cross currency swaps, coterminous with the debentures, to effectively convert the Canadian dollar denominated offering into U.S. dollars. The Company designated the entire notional amount of the cross currency fixed-for-fixed interest rate swap and related short-term U.S. dollar payables created by the monthly accruals of the swap settlement as a hedge of the foreign currency exposure of its net investment in the Generation Group'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 U.S. dollar 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 OCI) related to the net investment. A loss of \$29,286 (2014 - loss of \$9,970) was recorded in OCI for the three months ended March 31, 2015.

20. Financial instruments (continued)

(b) Derivative instruments and hedging relationships (continued)

(iv) Other derivatives

The Company 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 through 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.

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

The Company is party to an interest rate swap whereby, the Company pays a fixed interest rate of 4.47% on a notional amount of \$59,947 and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. As of March 31, 2015, the estimated fair value of the interest rate swap was a liability of \$1,026 (December 31, 2014 – liability of \$1,383). 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.

For derivatives that are not designated as cash flow hedges and for the ineffective portion of gains and losses on derivatives that are accounted for as hedges, the changes in the fair value are immediately recognized in earnings.

The effects on the consolidated statements of operations of derivative financial instruments not designated as hedges consist of the following:

	Three months ended March 31,	
	2015	2014
Change in unrealized loss (gain) on derivative financial instruments:		
Interest rate swaps	\$ (357)	\$ (390)
Energy derivative contracts	453	2,160
Total change in unrealized loss on derivative financial instruments	\$ 96	\$ 1,770
Realized loss (gain) on derivative financial instruments:		
Interest rate swaps	469	490
Energy derivative contracts	(647)	(3,966)
Total realized gain on derivative financial instruments	\$ (178)	\$ (3,476)
Gain on derivative financial instruments not accounted for as hedges	(82)	(1,706)
Ineffective portion of derivative financial instruments accounted for as hedges	(15)	1,343
Gain on derivative financial instruments	\$ (97)	\$ (363)

21. Comparative figures

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

NOTES

NOTES

CORPORATE INFORMATION

DIRECTORS

Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.

Christopher Ball – Executive Vice-President, Corpfinance International Ltd.

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.

George Steeves – Principal, True North Energy

Masheed Saidi – Former Executive VP and Chief Operating Officer, US Transmission, National Grid USA

Dilek Samil – Former Executive VP and Chief Operating Officer, NV Energy

THE MANAGEMENT GROUP

Ian Robertson, Chief Executive Officer

Chris Jarratt, Vice-Chair

David Bronicheski, Chief Financial Officer

HEAD OFFICE

354 Davis Road

Oakville, Ontario, L6J 2X1

Telephone – 905-465-4500

Fax – 905-465-4514

Website – www.algonquinpowerandutilities.com

REGISTRAR AND TRANSFER AGENT

CST Trust Company

320 Bay Street

Toronto, Ontario, M5H 4A6

AUDITORS

Ernst & Young, LLP

Toronto, Ontario

STOCK EXCHANGE

The Toronto Stock Exchange:

AQN, AQN.PR.A, AQN.PR.D

LEGAL COUNSEL

Blake, Cassels & Graydon LLP

354 Davis Road
Oakville, Ontario
Canada L6J 2X1
Tel: 905-465-4500
Fax: 905-465-4514
www.algonquinpowerandutilities.com

