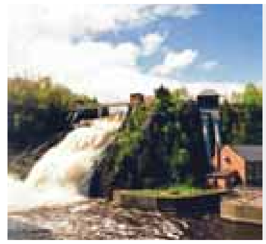
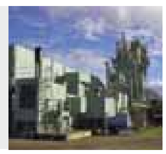
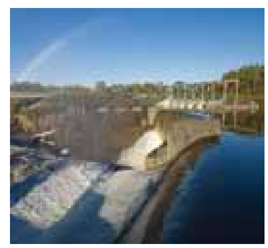
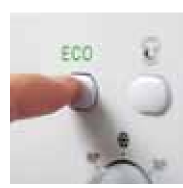


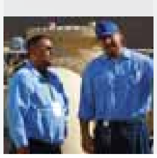
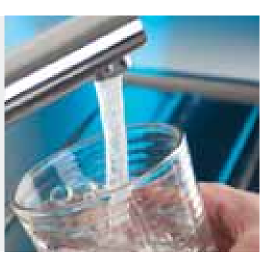
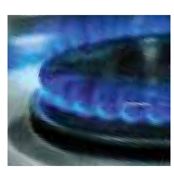




2011 Annual Report







Algonquin Power & Utilities Corp.

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Belleterre, QC

Algonquin Power & Utilities Corp. is a leading power and utility company with a diversified $1.2 billion portfolio of clean renewable electric generation and sustainable rate regulated utility businesses in North America. We are focused on creating shareholder value through the prudent investment in power and utility assets, delivering stable earnings and cash flows coupled with the opportunity for future growth.

Our organization is headed by an experienced executive management team with over 60 years of combined experience in the power and utility sectors. Their experience is evidenced by the successful growth in our asset base from our first generating station investment made 15 years ago to over 70 stable and sustainable power and utility assets generating revenues of over a quarter of a billion dollars today.

Ian Robertson
CEO

Ken Moore
Chairman of the Board of Directors

2011 Letter to Shareholders

Dear Fellow Shareholders,

Algonquin Power & Utilities Corp. (the "Company") had a very active year in 2011, with our power division, Algonquin Power Co. showing increased energy production throughout the year along with several exciting growth milestones, and our regulated utilities group, Liberty Utilities Co. strategically increasing our regulated utility footprint across the United States.

The Company achieved growth over 2010 earnings and saw attractive shareholder returns through our stable and growing dividend, coupled with capital appreciation which is underpinned by increases in genuine earnings and cashflow arising from the successful execution on our growth strategies.

We have grown our regulated utilities business in the United States and further diversified our power business in Canada during the year, setting the stage for increased stability in earnings going forward as we complete the strategic shift to a growth oriented, dividend paying organization. We have delivered total shareholder return of 73 per cent since our strategic conversion to a corporate structure in late 2009; the result of a clear focus on capital appreciation and dividend growth.

Of course, value accretive growth is not something that simply materializes. We have increased our business development capacities in both our power and utility businesses over the course of the last few years. Our teams are industriously working on sourcing and evaluating the right opportunities for the Company – opportunities that will provide increased per share earnings and cash-flow to the organization, whether in the power or utilities business.

Our development teams delivered many successes in 2011. The power development team commissioned the 26 MW Red Lily wind power generation facility in Saskatchewan, commenced construction of the 17 MW St. Leon wind power project expansion in Manitoba, announced a 75MW wind generation project in Ontario and further diversified the renewable power portfolio with the announcement of our first 10 MW solar project to be constructed near Cornwall, Ontario.

Our utilities development team marked the beginning of the year with the addition of our first electricity distribution business in Lake Tahoe, California and the announcement of an agreement to acquire regulated natural gas distribution assets in Missouri, Illinois and Iowa, further expanding our footprint in the United States. Our team made substantial progress in moving the previously announced acquisition of Granite State Electric Company and EnergyNorth Natural Gas Inc. through the regulatory approval process in New Hampshire. Together, these new acquisitions will bring the total customers served by the Liberty Utilities family to close to 1/3 of a million.

We remain committed in 2012 to deliver continued growth in both our power and utility businesses and our development teams are working on the next projects and acquisitions that you will hear about in the future.

The Strength of our Portfolio

The key to our ongoing business success is the profitable management of our existing portfolio of long-lived, stable power and utility assets. Our asset management and operations teams are mandated to ensure that our existing portfolio delivers on earnings and cashflow expectations. This group of assets will continue to be leveraged to generate additional opportunities in the form of utility system expansion, facility upgrades, equipment refurbishments and repowering of generating facilities, to name a few.

Total Shareholder Return

During 2011, we were very pleased to announce that the Board of Directors approved two dividend increases; an eight per cent increase in March and a seven and a half percent dividend increase in August, bringing the total annual dividend to 28 cents, paid quarterly at the rate of 7 cents per common share. The increase is consistent with the Company's strategy of delivering a compelling total shareholder return comprised of an attractive current dividend yield and capital appreciation driven by earnings and cash flow growth.

Also in 2011, we introduced a Dividend Reinvestment Plan or "DRIP" that allows Canadian holders of common shares a convenient means to acquire additional Company shares through the reinvestment of cash dividends paid on shareholdings. Shares to be delivered under the DRIP are either purchased in the open market or issued at a discount of up to 5% to current market prices. The main advantages of enrolling in the DRIP include the convenience of having cash dividends automatically reinvested instead of receiving cash dividends, and the ability to purchase additional Company shares without having to pay commissions, service charges, or brokerage fees. We are very pleased that the DRIP was well received by our shareholders with, at the end of 2011, 17 per cent of our shares having been enrolled in the DRIP.

As part of our efforts to align our employees' interests with those of the Company, 2011 saw the introduction of an Employee Share Purchase Plan that allows the opportunity for our employees to participate directly in ownership of the Company through the regular purchase of shares. We believe engaged and empowered employees are the cornerstone to running a successful business, and ownership in their Company is a key to our continued future success.

Building on a Strong Partnership

Our relationship with Emera, our largest shareholder, continues to remain strong with both companies fully committed to further capitalizing on the relationship. We have announced a number of acquisitions in which Emera has committed equity financing and we are working with regulatory bodies to ensure approval of their continued investment. Currently, Emera owns approximately twelve per cent of the Company, and under our Strategic Investment Agreement announced in 2011, this ownership position is envisioned to grow to 25 per cent.

Our Focus in 2012

Continuing our strong focus on growth evident over the past few years, we have a full 2012 schedule of power developments, regulatory approvals and integrations of our utility acquisitions. We are comfortable that we have the necessary resources in both our power and utility businesses to successfully achieve the growth milestones ahead of us.

In our power business we have over 350 MW of contracted wind and solar projects in the development pipeline that we are moving through the appropriate permitting processes, with a goal of constructing at least a project a year between now and 2016. Our focus on acquiring and developing long-lived assets with contracted off-take agreements with utility grade counterparties is evident in our average power purchase agreement life growing from 13 years in 2011 to 19 years by 2017.

In our utility business we believe that supporting a number of utility operations with common systems infrastructure will allow us to provide the local, responsive and caring customer service which is the foundation of delivering on our utility investment proposition. We are confident that this customer-centric utility proposition is resonant with our community, customer, employee and regulator stakeholders. We have two pending regulatory proceedings underway and are confident we will bring these to successful close and integrate these new acquisitions into the utility family during 2012. We are pleased to be growing our utility footprint in the United States and supplying safe, reliable and cost effective water, electricity and natural gas services to our growing customer base.

In Summary

Against the backdrop of our recent vigorous growth trajectory, we see 2012 as a year of continuing the momentum by executing on additional initiatives in a measured and paced manner and continuing our investment to develop future opportunities. Our board of directors continues to provide valuable and important governance and oversight of the Company in the review and balancing of the many opportunities that come our way.

Our goals and strategies will guide our actions throughout 2012. We believe our employees are functioning as a well-coordinated team, committed to achieving our goals and ensuring high-levels of corporate stewardship. Successful companies run on the dedication and commitment of their employees. To them, we attribute our success.

We have confidence in our ability to deliver on the value creation opportunities that lie ahead for our Company and look forward to sharing our future success.

Ian Robertson
Chief Executive Officer

Ken Moore
Chairman of the Board of Directors

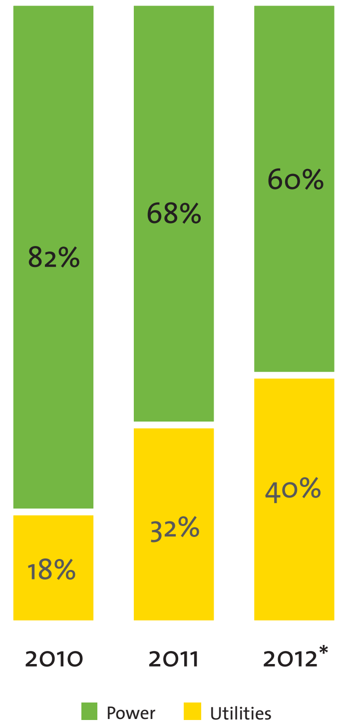
ALGONQUIN
Power & Utilities Corp.

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

In 2012, our goal is to continue to advance our announced projects and acquisitions to positively impact our cash-flow and earnings per share. We understand that a low risk profile is important to our many stakeholders and we continue to ensure a disciplined approach is taken in financing activities, counterparty relationships, interest rates and commodity exposure to ensure we maximize our growth activities and carefully manage our existing business. Overall, our medium-term plan targets greater than 12 per cent total shareholder return, comprised of earnings and asset growth greater than 15 per cent and growth in earnings per share of at least five per cent. It is positive impacts of our growth activities that allow the Board of Directors the discretion to increase the dividend in a paced and measured way.

We will see a strategic shift in our portfolio this year with the addition of the announced acquisitions into the Liberty Utilities family. In 2009 our portfolio of assets was weighted to the power generation side of the business. Over the past few years we have made several acquisitions in the United States utility sector that will see our company become more balanced between the power and utility sectors, offering further diversification and contributing to the stability of our cash flow profile.

EBITDA Split



* Projected 2012 EBITDA Split

EBITDA = Earnings before interest, taxes, depreciation, and amortization

Algonquin Power Co., our electric generation subsidiary, generates and sells electrical energy through a diverse portfolio of clean, renewable power generation facilities across North America. The portfolio includes 41 renewable energy facilities and 9 thermal energy facilities representing more than 450 MW of installed capacity. Growth in this business is delivered through our pipeline of committed power development projects representing over 350MW and $1 billion in investment opportunity.

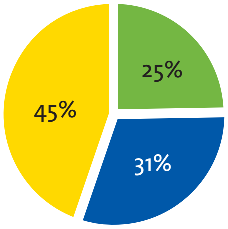
Rawdon, QC

Looking forward in the power business, we have announced well-paced development and acquisition initiatives which will carry us through 2016. This growth further diversifies our business both technologically, with the addition of solar generation to the portfolio, and geographically with our recently announced acquisition of 245MW of United States based wind generation.

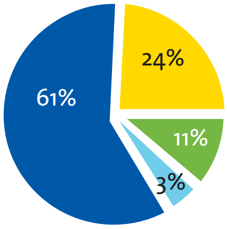
An important element to our ongoing business is the profitable management of our existing portfolio of long-lived, stable power assets. An example of this approach to asset management is well demonstrated by our Windsor Locks co-generation facility. In 2011 our team began preliminary plans to re-power the facility, which is a 56 MW natural gas powered electrical and steam energy generating station. The facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to a near-by specialty paper manufacturer. The project entails the installation of a 14 MW combustion gas turbine which is appropriately sized to meet the electrical and steam requirements of the manufacturing facility. This leaves the existing 56 MW turbine available to operate and sell into the New England market when it is commercially profitable to do so. We expect this project to be finished mid-year 2012 and provide a more economical operating model for the plant in the long-term.

Our 2012 objectives of continued growth in our power business are in place and our development teams are working on the next projects and acquisitions that you will hear about in the future.

Red Lily, SK



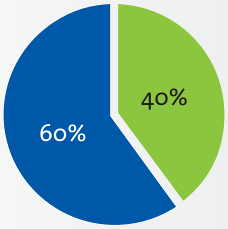
2011 Power Portfolio
% earnings contribution



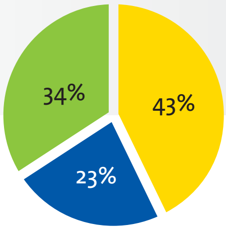
2016 Power Portfolio
% earnings contribution

Liberty Utilities Co., our U.S. based utility business, currently provides cost-of-service rate regulated water and electric distribution utility services to more than 120,000 customers primarily located in Arizona, Texas, and California. In 2012, Liberty Utilities Co. will grow further with the acquisition of New Hampshire, Missouri, Iowa and Illinois electric and natural gas distribution utilities serving an additional approximately 213,000 customers. We are committed to expanding this business organically through growth within each utility and through further accretive acquisitions of high quality water, electricity and natural gas distribution assets.

Our utilities business landscape will see significant change over the next few years, with the addition of several new rate regulated electricity and gas distribution assets to the portfolio. The year 2011 was spent seeking regulatory approval on our announced acquisitions and creating detailed plans for the integration of these new assets in the Liberty Utilities operating systems, which will contribute significantly to the growth and diversification of the company through 2016.



2011 Utilities Portfolio
% earnings contribution
Water Electric



2016 Utilities Portfolio
% earnings contribution
Water Electric Gas

Our approach to the ongoing management of our portfolio on the utilities side of the business is well demonstrated through our team's focus on daily operations and system improvements, managing facility rates for our facilities, and planning for growth. As an example, our electricity distribution business in Lake Tahoe, California, serves some of the area ski resorts, providing reliable power for running their businesses. Many of these resorts have major expansion plans underway to add new lifts, terrain and snow making equipment over the next few years. We must keep pace with the growth in the region by upgrading, rebuilding and maintaining our infrastructure in order to continue the reliable service we have become known for in the area. Our team monitors growth in the area and develops carefully considered capital spending plans to ensure our facilities can meet any new capacity that we may be required to deliver.

In 2012 we will continue to target the successful integration of our announced utilities acquisitions while carefully managing the growth within our existing utilities.

ALGONQUIN Power & Utilities Corp.

Management's Discussion and Analysis

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

Management of Algonquin Power & Utilities Corp. ("APUC") has prepared the following discussion and analysis to provide information to assist its shareholders' understanding of the financial results for the three and twelve months ended December 31, 2011. This Management's Discussion and Analysis ("MD&A") should be read in conjunction with APUC's audited consolidated financial statements for the years ended December 31, 2011 and 2010 prepared in accordance with U.S. generally accepted accounting principles ("GAAP"). See *Change in Accounting Policies* for a discussion on the reasons for this change. This material is available on SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com. Additional information about APUC, including the most recent Annual Information Form ("AIF") can be found on SEDAR at www.sedar.com.

This MD&A is based on information available to management as of March 18, 2012.

Caution concerning forward-looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of APUC with respect to future events, based upon assumptions relating to, among others, the performance of APUC's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of APUC, its future plans and its dividends to shareholders. Statements containing expressions such as "anticipates", "believes", "continues", "could", "expect", "estimates", "intends", "may", "outlook", "plans", "project", "strives", "will", and similar expressions generally constitute forward-looking statements.

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

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("Adjusted EBITDA") and "per share cash provided by operating activities" are used throughout this MD&A. The terms "adjusted net earnings", "per share cash provided by operating activities" and Adjusted EBITDA are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA and "per share cash provided by operating activities" can be found throughout this MD&A.

Overview and Business Strategy

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

APUC's current quarterly dividend to shareholders is $0.07 per share or $0.28 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, reduce short term debt obligations and mitigate the impact of fluctuations in foreign exchange rates. Additional increases in the level of dividends paid by APUC are at the discretion of the APUC Board of Directors (the "Board") and dividend levels shall be reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to 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 currently conducts its business primarily through two autonomous subsidiaries: Algonquin Power Co. ("APCo") which owns and operates a diversified portfolio of renewable energy assets and Liberty Utilities Co. ("Liberty Utilities") which owns and operates a portfolio of North American rate regulated utilities.

Algonquin Power Co.

APCo generates and sells electrical energy through a diverse portfolio of renewable power generation and clean thermal power generation facilities across North America. APCo seeks to deliver continuing growth through development of greenfield power generation projects, accretive acquisitions of electrical energy generation facilities as well as development of expansion opportunities within APCo's existing portfolio of independent power facilities. As at December 31, 2011, APCo owns or has interests in hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New Brunswick, New York State, New Hampshire, Vermont, Maine and New Jersey with a combined generating capacity of approximately 165 MW. APCo also owns a 104 MW wind powered generating station in Manitoba and holds exchangeable debt securities in a 26 MW wind powered generating station completed in early 2011 in Saskatchewan. All of the electrical output from the wind energy facilities are sold pursuant to long term power purchase agreements ("PPAs") with major utilities which have a weighted average remaining contract life of 20 years. Approximately 80% of the electrical output from the hydroelectric facilities is sold pursuant to long term PPAs with major utilities which have a weighted average remaining contract life of 8.5 years.

APCo owns thermal energy facilities with approximately 120 MW of installed generating capacity and holds ownership interests in three facilities having gross installed capacity of approximately 200 MW. Approximately 67% of the electrical output from the owned thermal facilities is sold pursuant to long term PPAs with major utilities and which have a weighted average remaining contract life of 11 years.

Liberty Utilities Co.

Liberty Utilities provides rate regulated electricity, natural gas and, water distribution and wastewater collection utility services. Liberty Utilities' underlying business strategy is to be a leading provider of safe, high quality and reliable utility services through a nationwide portfolio of moderate sized utilities and deliver stable and predictable earnings to APUC from these utility operations. In addition to encouraging and supporting organic growth within its service territories, Liberty Utilities is focused on delivering continued growth in earnings through acquisition opportunities which accretively expand its utility business portfolio. The utility businesses owned by Liberty Utilities operate under rate regulation, generally overseen by the public utility commissions of the states in which they operate. As a result of the current and expected growth of Liberty Utilities, Liberty Utilities has elected to organize the management of its utility operations by geographic region rather than by line of business. As a result of this decision, Liberty Utilities businesses operate under two separately managed regions - Liberty Utilities (South) and Liberty Utilities (West).

Liberty Utilities (South) operates in the states of Arizona, Texas, Missouri and Illinois and currently provides regulated water and wastewater utility services to approximately 76,000 customers in those states.

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

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

Major Highlights

Corporate Highlights

Dividend Increased to $0.28 for each Common Share

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

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

Strengthened Liquidity - Issuance of $95.3 million of Common Shares

On October 27, 2011, APUC completed a public offering (the "Offering") of 15,100,000 common shares at a price of $5.65 per share, for gross proceeds of approximately $85.3 million. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

The net proceeds of the Offering will be used to fund a portion of the investment related to previously announced growth initiatives for both Liberty Utilities and APCo, to partially repay existing indebtedness and for other general corporate purposes.

Strengthened Balance Sheet - Conversion of Convertible Debentures to Equity

Effective May 16, 2011 ("Redemption Date"), APUC redeemed $2.1 million, all of the remaining issued and outstanding, Series 1A 7.5% convertible unsecured subordinated debentures due November 30, 2014 ("Series 1A Debentures") and issued 430,666 share of APUC. Between January 1, 2011 and the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,976 shares of APUC.

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

Strategic Investment Agreement with Emera

On April 29, 2011, APUC entered into a strategic investment agreement (the "Strategic Agreement") with Emera which establishes how APUC and Emera will work together to pursue specific strategic investments of mutual benefit. The Strategic Agreement builds on the strategic partnership effectively established between the two companies in April 2009.

The Strategic Agreement outlines "areas of pursuit" for each of APUC and Emera. For APUC, these include investment opportunities relating to unregulated renewable generation, small electric utilities and gas distribution utilities. For Emera, these include investment opportunities related to regulated renewable projects within its service territories and large electric utilities. These “areas of pursuit” are intended to represent investment areas in which there is potential overlap between Algonquin and Emera and are not exhaustive of either company’s business focus and do not limit in any way the activities which either APUC or Emera can undertake. Each of APUC or Emera are free to undertake independently investments within their own “area of pursuit” and outside the other party’s “areas of pursuit”. Under the Strategic Agreement, to the extent either APUC or Emera encounter opportunities which fall within the other’s “areas of pursuit”, they are committed to work with the other party in the development of such investment opportunities.

As an element of the Strategic Agreement, Emera’s allowed common equity interest in APUC will be increased from 15% to 25%. The Strategic Agreement was approved by shareholders at the annual and special general meeting held on June 21, 2011.

Liberty Utilities Highlights

California Utility Acquisition and Senior Debt Financing

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of U.S. $136.1 million, subject to certain working capital and other closing adjustments. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility assets, California Pacific Electric Company (“Calpeco”).

Filing of Approval Application for 100% of California Utility

On April 29, 2011, Emera agreed to sell its 49.999% direct ownership in the California Utility to Liberty Utilities, with closing of such transaction subject to regulatory approval. As consideration, Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the transfer of 100% of the California Utility to Liberty Utilities (expected in early 2012) and the balance of the shares will be issued following completion of the California Utility’s first rate case, expected to be completed in early 2013.

New Hampshire Utility Acquisitions

On December 9th, 2010 Liberty Utilities entered into agreements to acquire all issued and outstanding shares of Granite State Electric Company (“Granite State”), a regulated electric distribution utility in New Hampshire, and EnergyNorth Natural Gas, Inc. (“EnergyNorth”), a regulated natural gas distribution utility in New Hampshire, both from National Grid USA (“National Grid”), for total consideration of U.S. $285.0 million plus certain working capital adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $250 million.

The closing of the transaction is subject to approval by the New Hampshire Public Utilities Commission (“NHPUC”). Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

Midwest Utility Acquisitions

On May 13, 2011, Liberty Utilities entered into an agreement with Atmos to acquire their regulated natural gas distribution utility assets (the “Midwest Gas Utilities”) located in Missouri, Iowa, and Illinois. Total purchase price for the Midwest Gas Utilities is approximately U.S. $124 million, subject to certain working capital and other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million.

The closing of the transaction is subject to approval by the Missouri Public Service Commission (“MPSC”), Iowa Utilities Board (“IUB”), and Illinois Commerce Commission (“ICC”). Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Liberty Utilities Credit Facility

On January 19, 2012, Liberty Utilities entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility can be increased to accommodate future working capital needs or other requirements.

Algonquin Power Co. Highlights

Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind power projects in the United States (the “Projects”) from Gamesa Corporación Tecnológica, S.A. (“Gamesa”). APCo will contribute U.S. $269 million to partially fund the acquisition of the Projects; tax assisted equity investors will contribute U.S. $360 million. APCo intends to finance its investment with approximately 45% debt and 55% equity. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissioning near the end of 2012.

The Projects consist of four facilities, Minonk (200MW), Senate (150MW), Pocahontas Prairie (80MW) and Sandy Ridge (50MW) located in the states of Illinois, Texas, Iowa and Pennsylvania, respectively. Pocahontas Prairie and Sandy Ridge have recently reached their commercial operation dates (“COD”) in February 2012, and Senate and Minonk are in construction with COD anticipated in Q4 2012. Total annual energy production from the four facilities is expected to be 1,644 GW-hrs per year. The Projects are comprised of 240 Gamesa G9X-2.0 MW wind turbines. The Projects each have entered into a 20 year contract with Gamesa to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities.

The Projects have long term, fixed price power sales contracts (the “Power Sales Contracts”) with a weighted average life of 11.8 years (Minonk and Sandy Ridge 10 years, Senate 15 years). Approximately 73% of energy revenues would be earned under the Power Sales Contracts. All energy produced in excess of that sold under the Power Sales Contracts, together with ancillary services including capacity and renewable energy credits, will be sold into the energy markets in which the facilities are located.

St. Leon Facility Expansion

On July 18, 2011, APCo entered into a 25-year power purchase agreement with Manitoba Hydro in respect of a 16.5 MW expansion (“St. Leon II”) of its existing St. Leon wind energy project located in the Province of Manitoba.

Construction of this project commenced on August 30, 2011. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The total capital cost of the project is expected to be $29.5 million. The project is expected to achieve commercial operation early in the second quarter of 2012 with revenues in the first full year of operating following commissioning expected to be $3.8 million.

Red Lily Wind Project

On February 28, 2011 the 26.4 MW wind generation facility in southeastern Saskatchewan ("Red Lily I") commenced commercial operation under the PPA. APUC's investment in Red Lily I has been initially structured in the form of senior and subordinated debt investment of approximately $19.6 million with returns to APUC from the project coming in the form of interest payments and other fees in 2011. APUC earned $1.6 million in interest income and $1.9 million in other payments and fees in 2011. APUC has the option to formally exchange its debt investment for a 75% equity position in the facility in 2016.

New Projects Under Development

As of March 18, 2012, APCo had been awarded or acquired interests in seven major power development projects that significantly expands the company's electrical generation capacity by 350 MW and once completed will increase the company's annual generation production by over 1,200 GWhrs. Each project has a power purchase agreement with a Canadian provincial utility and has a contract length of 20 years or longer.

The following summarizes a number of projects under development and for which PPA's have been awarded since December 2010.

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island	Ontario	75	$230.0	2014	25	247.0
Morse Wind [1]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase	Quebec	24	$70.0	2013	20	86.0
Val Eo	Quebec	24	$70.0	2015	20	66.0
St. Leon II	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

[1]The Morse Wind Project is comprised of three contiguous projects with 25 MW in aggregate installed generating capacity. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011.

A more detailed discussion of these projects is presented within the *APCo: Development Division* business unit analysis.

Senior Unsecured Debentures

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

Credit Facility Renewal

On February 14, 2011 APCo renewed the Facility with its bank syndicate for a three year term with a maturity date of February 14, 2014. The committed credit under the Facility is $120 million.

2011 Annual results from operations

APUC continued to show strong results through 2011. Over the past two years, APUC has focused its efforts on a number of value creation initiatives that, through their completion, are now contributing to the growth evident in APUC revenues, adjusted EBITDA and net earnings. These initiatives include Liberty Utilities' acquisition of the California Utility and successful prosecution of rate cases, APCo's refurbishment of the Energy from Waste facility, acquisition of the Tinker Hydro facility and completion of construction and commissioning of the Red Lily I Wind Farm. As a result, for the year ended December 31, 2011, APUC reported total revenue of $276.6 million as compared to $180.4 million during the same period in 2010, an increase of $96.2 million or 53%.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. (see Non-GAAP Performance Measures). For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million.

Key Selected Annual Financial Information

	Year ended December 31		
	2011 (millions)	**2010 (millions)**	**2009[5] (millions)**
Revenue	**$ 276.6**	$ 180.4	$ 187.3
Adjusted EBITDA [1, 3]	**$ 105.2**	$ 75.1	$ 79.4
Cash provided by Operating Activities	**69.7**	41.4	48.0
Net earnings attributable to Shareholders	**23.4**	18.0	31.3
Adjusted net earnings [1, 3]	**41.6**	22.5	30.5
Dividend declared to Shareholders	**32.4**	22.8	19.3
Per share			
Basic net earnings	**$ 0.20**	$ 0.19	$ 0.39
Adjusted net earnings [1, 3]	**$ 0.36**	$ 0.24	$ 0.38
Diluted net earnings	**$ 0.20**	$ 0.19	$ 0.39
Cash provided by Operating Activities [2, 3]	**$ 0.60**	$ 0.44	$ 0.60
Dividends declared to Shareholders	**$ 0.27**	$ 0.24	$ 0.24
Total Assets	**1,282.6**	1,016.9	1,013.4
Long Term Liabilities[4]	**332.7**	260.0	241.4

[1] APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.
[2] APUC uses per share cash provided by operating activities to enhance assessment and understanding of the performance of APUC.
[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.
[4] Includes Long-term liabilities and Current portion of long-term liabilities.
[5] Presented using Canadian Generally Accepted Accounting Principles.

The major factors resulting in the increase in APUC revenue in the year ended December 31, 2011 as compared to the corresponding period in 2010, are set out as follows:

	Year ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 180.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	78.1
Liberty Utilities (South) revenue increases primarily due to rate case approvals	8.8
Energy-from-Waste facility	7.6
Effect of hydrology resource compared to comparable period in prior year	6.8
Effect of wind resource compared to comparable period in prior year	3.0
Impact of the weaker U.S. dollar	(5.4)
Tinker Hydro/ Algonquin Energy Services ("AES")	(1.4)
Windsor Locks	(0.9)
All Other	(0.4)
Current Period Revenue	$ 276.6

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

APUC reports its results in Canadian dollars. For the year ended December 31, 2011, APUC experienced an average U.S. exchange rate to each Canadian dollar of approximately U.S. $0.989 as compared to U.S. $1.031 in the same period in 2010. As such, any year over year variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the year ended December 31, 2011 totalled $105.2 million as compared to $75.1 million during the same period in 2010, an increase of $30.1 million or 40%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved average hydrology and wind resources in APCo's Renewable Energy division and improved results from the EFW facility. This increase was partially offset by lower results at Windsor Locks and Tinker facilities, as well as the impact of the weaker U.S. dollar as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the year ended December 31, 2011, net earnings attributable to Shareholders totalled $23.4 million as compared to $18.0 million during the same period in 2010, an increase of $5.4 million. Basic net earnings per share totalled $0.20 for the year ended December 31, 2011, as compared to $0.19 during the same period in 2010.

For the year ended December 31, 2011, net earnings totalled $27.3 million as compared to $18.4 million during the same period in 2010, an increase of $8.9 million. A number of factors resulted in increased net earnings, including an increase of $32.2 million due to increased earnings from operating facilities, $0.5 million in increased interest and dividend income, $2.2 million related to increased recoveries of income tax expense (see – *2011 Annual Corporate and Other Expenses*) and $0.8 million due to decreased amortization and depreciation expense. These items were partially offset by increased management and administration expenses of $2.6 million, $5.6 million due to increased interest expense, $14.0 million due write downs of intangibles and property, plant and equipment (see - *2011 Annual Corporate and Other Expenses*) and $4.7 million due to increased losses on derivative financial instruments as compared to the same period in 2010.

During the year ended December 31, 2011, cash provided by operating activities totalled $69.7 million or $0.60 per share as compared to cash provided by operating activities of $41.4 million, or $0.44 per share during the same period in 2010, an increase of approximately 36% per share. Cash per share provided by operating activities is a non-GAAP measure. Cash provided by operating activities exceeded dividends declared by 2.1 times during the year ended December 31, 2011 as compared to 1.8 times dividends paid during the same period in 2010. The change in cash provided by operating activities after changes in working capital in the year ended December 31, 2011, is primarily due to increased cash from operations, partially offset by increased interest expense and increased management and administration expense as compared to the same period in 2010.

2011 Fourth quarter results from operations

Key Selected Fourth Quarter Financial Information

	Three months ended December 31 2011 (millions)	Three months ended December 31 2010 (millions)
Revenue	**$ 72.1**	$ 48.4
Adjusted EBITDA [1, 3]	**$ 24.3**	$ 20.8
Cash provided by Operating Activities	**4.6**	15.1
Net earnings (loss) attributable to Shareholders	**(8.5)**	15.6
Adjusted net earnings[1, 3]	**6.7**	18.2
Dividends declared to Shareholders	**9.5**	5.7
Per share		
Basic net earnings (loss)	**$ (0.07)**	$ 0.17
Adjusted net earnings[1, 3]	**$ 0.05**	$ 0.19
Diluted net earnings (loss)	**$ (0.07)**	$ 0.17
Cash provided by Operating Activities [2, 3]	**$ 0.03**	$ 0.17
Dividends declared to Shareholders	**$ 0.07**	$ 0.06

[1] APUC uses Adjusted EBITDA and Adjusted net earnings to enhance assessment and understanding of the operating performance of APUC without the effects of certain accounting adjustments which are derived from a number of non-operating factors, accounting methods and assumptions.
[2] APUC uses per share cash from operating activities to enhance assessment and understanding of the performance of APUC.
[3] Non-GAAP measure - see applicable section later in this MD&A and the caution regarding non-GAAP measures on page 1.

For the three months ended December 31, 2011, APUC reported total revenue of $72.1 million as compared to $48.4 million during the same period in 2010, an increase of $23.7 million or 49%. The major factors resulting in the increase in APUC revenue in the three months ended December 31, 2011 as compared to the corresponding period in 2010 are set out as follows:

	Three months ended December 31, 2011 (millions)
Comparative Prior Period Revenue	$ 48.4
Significant Changes:	
Acquisition of the California Utility – January 1, 2011	20.8
Liberty Utilities (South) revenue increases primarily due to rate case approvals	1.4
Effect of wind resource compared to comparable period in prior year	1.6
Windsor Locks	(0.9)
Impact of the stronger U.S. dollar	0.7
Other	0.1
Current Period Revenue	$ 72.1

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

APUC reports its results in Canadian dollars. For the three months ended December 31, 2011, APUC experienced an average U.S. exchange rate for each Canadian dollar of approximately U.S. $1.023 as compared to U.S. $1.013 in the same period in 2010. As such, any quarter over quarter variance in revenue or expenses, in local currency, at any of APUC's U.S. entities are affected by a change in the average exchange rate, upon conversion to APUC's reporting currency.

Adjusted EBITDA in the three months ended December 31, 2011 totalled $24.3 million as compared to $20.8 million during the same period in 2010, an increase of $3.5 million or 17%. The increase in Adjusted EBITDA is primarily due to increased earnings from operations primarily resulting from Liberty Utilities' acquisition of the California Utility and increased revenues resulting from the completion of rate cases, improved wind resource in APCo's Renewable Energy and the impact of the stronger U.S. dollar. This increase was partially offset by lower results at Windsor Locks as compared to the same period in 2010. A more detailed analysis of these factors is presented within the reconciliation of Adjusted EBITDA to net earnings set out below (see Non-GAAP Performance Measures).

For the three months ended December 31, 2011, net loss attributable to Shareholders totalled $8.5 million as compared to net earnings of $15.6 million during the same period in 2010, a decrease of $24.2 million. Net loss per share totalled ($0.07) for the three months ended December 31, 2011, as compared to net earnings of$0.17 during the same period in 2010.

For the three months ended December 31, 2011, net loss totalled $8.1 million as compared to net earnings of $15.8 million during the same period in 2010, a decrease of $23.9 million. A number of factors resulted in decreased net earnings for the three months ended December 31, 2011, including $0.5 million related to increased loss on foreign exchange, $1.1 million due to increased interest expense, $9.8 million related to lower recoveries of income tax expense (see *Fourth Quarter Corporate and Other Expenses)*, $14.0 million due to write downs of intangibles and property, plant and equipment (see - *Fourth Quarter Corporate and Other Expenses*) and $3.4 million due to increased losses on derivative financial instruments as compared to the same period in 2010. These items were partially offset by an increase of $2.9 million due to increased earnings from operating facilities, a decrease of $0.3 million due to reduced depreciation and amortization expense, a decrease of $0.3 million due to reduced management and administration expense and a decrease of $1.2 million due to reduced acquisition costs as compared to the same period in 2010.

During the three months ended December 31, 2011, cash provided by operating activities totalled $4.6 million or $0.04 per share as compared to cash provided by operating activities of $15.1 million, or $0.16 per share during the same period in 2010. Cash per share provided by operating activities is a non-GAAP measure. The change in cash provided by operating activities after changes in working capital in the three months ended December 31, 2011, is primarily due to a modest increase in cash from operations, offset by increased interest expense and reduced tax recoveries as compared to the same period in 2010.

Outlook

APCo

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

APCo's energy services business, AES, anticipates that, based on the expected load forecast for its existing contracts, the APCo owned assets will provide almost 50% of the energy required to service its customers in the first quarter of 2012.

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the Independent System Operator New England ("ISO NE") day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

The EFW facility "tip or pay" waste supply agreement with the Region of Peel (the "Region") expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility. For additional information, see *APCo Divisional Outlook – Thermal Energy*.

On January 27, 2012, APCo announced that it plans not to proceed with the previously announced U.S. $83 million minority investment in First Wind Holdings, LLC's ("First Wind") wind energy facilities portfolio in the North East United States. The longer than anticipated regulatory process in Maine and the number of new acquisition and development opportunities announced since April 2011 contributed to the decision not to proceed with the investment.

Liberty Utilities

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

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011.

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the California Public Utilities Commission ("CPUC") seeking, among other things, an increase of 10.0%, or $7.5 million in general rates. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

Algonquin

APCo: Renewable Energy

	Three months ended December 31			Year ended December 31		
	Long Term Average Resource	**2011**	**2010**	**Long Term Average Resource**	**2011**	**2010**
Performance (GW-hrs sold)						
Quebec Region	**73.6**	**79.3**	84.1	**279.3**	**304.4**	275.9
Ontario Region	**32.1**	**28.2**	20.2	**134.6**	**121.1**	90.2
Manitoba Region	**105.0**	**119.7**	97.2	**372.0**	**383.8**	343.1
Saskatchewan Region*	**23.3**	**27.7**	-	**66.7**	**68.0**	-
New England Region	**13.4**	**23.7**	13.4	**58.8**	**70.2**	47.9
New York Region	**23.8**	**22.4**	24.4	**90.4**	**92.6**	79.6
Western Region	**12.7**	**11.8**	10.5	**65.9**	**65.5**	59.1
Maritime Region	**35.0**	**40.2**	55.5	**136.9**	**183.0**	148.6
Total	**318.9**	**353.0**	305.3	**1,204.6**	**1,288.6**	1,044.4
Revenue**						
Energy sales		**$ 23,816**	$ 21,867		**$ 87,566**	$ 80,117
Less:						
Cost of Sales – Energy***		**(737)**	(431)		**(3,762)**	(5,047)
Net Energy Sales		**$ 23,079**	$ 21,436		**$ 83,804**	$ 75,070
Other Revenue		**317**	563		**2,291**	2,122
Total Net Revenue		**$ 23,396**	$ 21,999		**$ 86,095**	$ 77,192
Expenses						
Operating expenses		**(7,933)**	(7,013)		**(26,116)**	(24,434)
Interest and Other income		**613**	151		**2,143**	783
Division operating profit (including other income)		**$ 16,076**	$ 15,137		**$ 62,122**	$ 53,541

* Actual production in the Saskatchewan Region reflects production since Red Lily I achieved commercial operation on February 23, 2011. APUC does not consolidate the operating results from this facility in its financial statements. Production from the facility is included as APUC manages the facility and has an option to acquire a 75% equity interest in the facility in 2016. The long term average resource reflects three and twelve months of production.

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

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

2011 Annual Operating Results

For the year ended December 31, 2011, the Renewable Energy division produced 1,288.6 GWhrs of electricity, as compared to 1,044.4 GWhrs produced in the comparable period, an increase of 23%. The increased generation is primarily due to strong average hydrology in the year as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 72,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 710,000 tons of CO_2 gas was prevented from entering the atmosphere in the year ended December 31, 2011.

During the year ended December 31, 2011, the division generated electricity equal to 107% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the year ended December 31, 2011, the Quebec, New England and Maritimes regions experienced resources significantly higher than long-term averages, producing 9%, 19%, and 34%, respectively, above long-term average resources, while the Manitoba, Saskatchewan, and New York regions experienced resources slightly higher than long-term averages, producing between 2 - 3% above long-term average resources. The Western region experienced resources at long-term averages while the Ontario region experienced resources 10% below long-term averages.

For the year ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $87.6 million, as compared to $80.1 million during the same period in 2010, an increase of $7.5 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares ‘net energy sales’ (energy sales revenue less energy purchases) as a more appropriate measure of the division’s sales results. For the year ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $83.8 million, as compared to $75.1 million during the same period in 2010, an increase of $8.7 million or 12%.

Revenue generated from APCo’s Ontario, Quebec and Western regions increased by $4.8 million due to a 15% overall increase in hydrology and $1.1 million due to an increase in weighted average energy rates, primarily in the Quebec region, of approximately 3% as compared to the same period in 2010. Revenue from APCo’s New England and New York region facilities increased $1.8 million due to increased average hydrology partially offset by $1.1 million due to a decrease in weighted average energy rates of approximately 15%. Revenue from the Manitoba region increased $2.7 million primarily due to a stronger wind resource and $0.4 million due to an increase in weighted average energy rates. Revenue in the Maritime region increased $0.5 million, primarily due to increased customer demand as compared to the same period in 2010. These increases were partially offset by a $1.4 million decrease in revenue at AES primarily due to decreased energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($11.6 million) and merchant sales of production in excess of customer demand and other revenue ($2.3 million). The division reported decreased revenue of $1.0 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

Red Lily I achieved commercial operations effective February 23, 2011. From the commercial operation date through December 31, 2011 Red Lily I produced 68.0 GWhrs of electricity. APCo’s economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. Under the terms of the agreements, APCo has the right to exchange these contractual and debt interests in Red Lily for a direct 75% equity interest in 2016. For the year ended December 31, 2011, APCo earned fees and interest payments from Red Lily I in the total amount of $3.5 million.

For the year ended December 31, 2011, energy purchase costs by AES totalled $3.8 million. During this same period, AES purchased approximately 45.5 GWhrs of energy at market and fixed rates averaging U.S. $84 per MWhr. The Maritime region generated approximately 80% of the load required to service its customers as well as AES’ customers in the year ended December 31, 2011. The division reported decreased energy purchase costs of $0.2 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses excluding energy purchases totalled $26.1 million, as compared to $24.4 million during the same period in 2010, an increase of $1.7 million or 7%. Operating expenses were impacted by $0.9 million related to increased operating costs associated with the Tinker Assets and AES, primarily the result of higher production levels in the Maritime region as compared to the same period in 2010. These increases were partially offset by reduced operating expenses of approximately $0.6 million at the hydroelectric facilities. Operating expenses include costs incurred in the period of $1.9 million associated with the pursuit of various growth and development activities, an increase of $0.7 million as compared to the same period in 2010. In the prior period, APCo recorded a reduction in the development costs due to a reimbursement of $0.9 million in connection with the Red Lily I wind project. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, interest and other income totalled $2.1 million, as compared to $0.8 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo’s earnings from its investment in Red Lily, as discussed above.

For the year ended December 31, 2011, Renewable Energy's operating profit totalled $62.1 million, as compared to $53.5 million during the same period of 2010, representing an increase of $8.6 million or 16%. For the year ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to increased hydrology and wind resources in the Canadian regions.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, the Renewable Energy division produced 353.5 GWhrs of electricity, as compared to 305.3 GWhrs produced in the same period in 2010, an increase of 16%. The increased generation is due to improved average wind generation in the quarter as compared to the comparable period in 2010. This level of production in 2011 represents sufficient renewable energy to supply the equivalent of 79,000 homes on an annualized basis with renewable power. Using new standards of thermal generation, as a result of renewable energy production, the equivalent of 194,000 tons of CO_2 gas was prevented from entering the atmosphere in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the division generated electricity equal to 111% of long-term projected average resources (wind and hydrology) as compared to 90% during the same period in 2010. In the fourth quarter of 2011, the New England region experienced resources significantly higher than long-term averages, producing 175% above long-term average resources, while the Manitoba, Saskatchewan, and Maritimes regions experienced resources higher than long-term averages, producing between 15 - 20% above long-term average resources. The Quebec region experienced resources above long-term averages, producing approximately 10% above long-term average resources. The Ontario, Western and New York regions experienced resources between 5 - 10% below long-term averages.

For the quarter ended December 31, 2011, revenue from energy sales in the Renewable Energy division totalled $23.8 million, as compared to $21.9 million during the same period in 2010, an increase of $1.9 million or 9%. As the purchase of energy by AES is a significant driver of revenue and component of variable operating expenses, the division compares 'net energy sales' (energy sales revenue less energy purchases) as a more appropriate measure of the division's sales results. For the quarter ended December 31, 2011, net revenue from energy sales in the Renewable Energy division totalled $23.1 million, as compared to $21.4 million during the same period in 2010, an increase of $1.7 million or 8%.

Revenue generated from APCo's Ontario, Quebec and Western regions increased by $0.5 million primarily due to a combination of an increase in weighted average energy rates of approximately 1% and a 5% overall increase in hydrology, primarily in the Ontario region as compared to the same period in 2010. Revenue from APCo's New England and New York region facilities increased $0.6 million primarily due to an increase of approximately 35% in average hydrology, offset by $0.6 million due to a decrease in weighted average energy rates of approximately 30% as compared to the same period in 2010. Revenue in the Maritime region decreased $0.3 million, primarily due to lower merchant sales of excess energy as compared to the same period in 2010. AES experienced a $0.2 million increase in revenue primarily due to increased average energy rates as compared to the same period in 2010. Revenue at AES primarily consists of wholesale deliveries to local electric utilities and retails sales to commercial and industrial customers in Northern Maine ($2.3 million) and merchant sales of production in excess of customer demand and other revenue ($0.9 million). Revenue from the Manitoba region increased $1.5 million due to an increased wind resource and $0.2 million due to an increase in weighted average energy rates as compared to the same period in 2010. The division reported decreased revenue of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

In the quarter ended December 31, 2011 Red Lily I produced 27.7 GWhr of electricity which was sold to SaskPower. APCo's economic return from its investment in Red Lily currently comes in the form of interest payments, fees and other charges. For the three months ended December 31, 2011, APCo earned fees and interest payments from Red Lily in the total amount of $0.7 million.

For the quarter ended December 31, 2011, energy purchase costs by AES totalled $0.7 million as compared to $0.4 million during the same period in 2010. During the quarter, AES purchased approximately 13.1 GWhr of energy at market and fixed rates averaging U.S. $54 per MWhr. The Maritime region generated approximately 70% of the load required to service its customers as well as AES's customers in the three months ended December 31, 2011.

For the quarter ended December 31, 2011, operating expenses excluding energy purchases totalled $7.9 million, as compared to $7.0 million during the same period in 2010, an increase of $0.9 million or 13%. Operating expenses were impacted by a $0.3 million increase in operating costs at Canadian hydroelectric facilities, primarily resulting from increased variable operating costs tied to higher production, partially offset by a decrease of $0.3 million related to decreased operating costs associated with the Tinker Assets as compared to the same period in 2010. Operating expenses include costs incurred in the period of $1.2 million associated with the pursuit of various growth and development activities, an increase of $0.5 million as compared to the same period in 2010. The division reported decreased expenses of $0.1 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest and other income totalled $0.6 million, as compared to $0.2 million during the same period in 2010. Interest and other income primarily consists of interest related to the senior and subordinated senior debt interest in the Red Lily I project. This amount is included as part of APCo's earnings from its investment in Red Lily, as discussed above.

For the quarter ended December 31, 2011, Renewable Energy's operating profit totalled $16.1 million, as compared to $15.1 million during the same period of 2010, representing an increase of $1.0 million or 7%. For the quarter ended December 31, 2011, Renewable Energy's operating profit exceeded APCo's expectations primarily due to stronger hydrology and wind generation in both the U.S. and Canadian regions.

Divisional Outlook – Renewable Energy

The APCo Renewable Energy division is expected to perform based on long-term average resource conditions for hydrology and long-term average wind resources in the first quarter of 2012.

AES anticipates that, based on the expected load forecast for its existing contracts, it will provide approximately 35,000 MWhrs of energy to its customers in the first quarter of 2012. AES anticipates that APCo owned assets will provide 43% of the energy required to service its customers in the first quarter of 2012 and that it will need to purchase approximately 20,000 MWhrs of energy from the ISO NE or similar market. AES has in place fixed price financial energy contracts to operationally hedge the price of the customer supply obligations which are not expected to be supplied by APCo owned assets and to minimize the volatility of the energy prices. These contracts in combination with the expected production from APCo owned assets are used to balance the monthly customer load.

APCo: Thermal Energy Division

	Three months ended December 31		Year ended	December 31
	2011	2010	2011	2010
Performance (GW-hrs sold)	**126.5**	120.6	**517.0**	465.4
Performance (tonnes of waste processed)	**42,145.0**	43,535.0	**166,825.0**	90,690.0
Performance (steam sales – billions lbs)	**308.4**	315.6	**1,209.4**	1,180.0
Revenue				
Energy/steam sales	**$ 10,582**	$ 11,506	**$ 46,666**	$ 49,860
Less:				
Cost of Sales – Fuel *	**(5,694)**	(5,492)	**(22,896)**	(22,348)
Net Energy/steam Sales Revenue	**$ 4,888**	$ 6,014	**$ 23,770**	$ 27,512
Waste disposal sales	**4,046**	4,164	**16,406**	9,039
Other revenue	**541**	311	**1,352**	1,209
Total net revenue	**$ 9,475**	$ 10,489	**$ 41,528**	$ 37,760
Expenses				
Operating expenses *	**(5,449)**	(5,492)	**(21,589)**	(21,469)
Interest and other income	**(74)**	100	**(6)**	633
Division operating profit (including interest and dividend income)	**$ 3,952**	$ 5,097	**$ 19,933**	$ 16,924

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

2011 Annual Operating Results

For the year ended December 31, 2011, the Thermal Energy Division produced 517.0 GW-hrs of energy as compared to 465.4 GW-hrs of energy in the comparable period of 2010. During the year ended December 31, 2011, the business unit's total production increased by 52.4 GWhr from the Windsor Locks facility and 6.1 GWhr from the EFW facility as compared to the same period in 2010. The comparable period includes 2.5 GWhr of production from landfill gas facilities which ceased generating energy and were closed in 2010.

The EFW facility processed 166,825 tonnes of municipal solid waste in 2011 as compared to 90,690 tonnes processed in the same period of 2010. The EFW facility processed waste for a full 12 month period in 2011 as compared to a 6 month period in 2010 when from January to July 2010 the facility was shut down as it underwent an extensive refurbishment. The current level of production resulted in the diversion of approximately 120,000 tonnes of waste from municipal solid waste landfill sites in the year ended December 31, 2011.

During the year ended December 31, 2011, the BCI and Windsor Locks facilities sold approximately 1,200 billion lbs of steam as compared to approximately 1,200 billion lbs of steam in the comparable period of 2010. During the year ended December 31, 2011, operations at the EFW facility generated 508 billion lbs of steam for the BCI facility as compared to 272 billion lbs of steam in the same period in 2010.

For the year ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $46.7 million, as compared to $49.9 million during the same period in 2010, a decrease of $3.2 million, or 6%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $23.8 million, as compared to $27.5 million during the same period in 2010, a decrease of $3.7 million, primarily arising from the weaker U.S. dollar and the power purchase agreement that concluded in April 2010 at the Windsor Locks facility.

The overall decrease in revenue from energy / steam sales was primarily due to a decrease of $5.7 million at the Windsor Locks facility as a result of decreased average energy rates, in part due to the change in operating model of the facility as it came off contract, partially offset by an increase of $4.8 million as a result of increased production, as compared to the prior year. The Sanger facility experienced a net decrease of $0.6 million as a result of decreased energy pricing, in part due to lower average landed price per mmbtu for natural gas, partially offset by $0.2 million as a result of increased production. Energy / steam sales revenue decreased $0.3 million in the period as a result of the closure of the LFG facilities, as compared to the prior year. The decrease in revenue was partially offset by $0.3 million at the BCI and EFW facilities as a result of increased production of energy and steam, as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below. The division reported decreased energy sales revenue of $1.7 million from operations as a result of the weaker U.S. dollar, as compared to the same period in 2010.

Revenue from waste disposal sales for the year ended December 31, 2011 totalled $16.4 million, as compared to $9.0 million during the same period in 2010. The increase was a result of the EFW facility refurbishment from January to July 2010 in the comparable period of 2010.

For the year ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $22.9 million, as compared with $22.3 million in the same period in 2010, an increase of $0.5 million.[1] The overall natural gas expense at the Windsor Locks facility increased U.S. $1.7 million (10%), primarily the result of a 10% increase in volume of natural gas consumed, as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the year was U.S. $4.84 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of U.S. $0.3 million (5%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the year was U.S. $4.42 per mmbtu. The division reported decreased fuel expenses of $0.8 million as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $21.6 million, as compared to $21.5 million during the same period in 2010, an increase of $0.1 million. The increase in operating expenses in the year was primarily due to $4.4 million in increased gas, consumables, repair and maintenance and wages at the EFW facility resulting from the outage at the facility in 2010, partially offset by $0.6 million in reduced operating costs at Windsor Locks, $2.0 million at BCI, primarily

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

the result of reduced natural gas costs due to the EFW facility generating more steam and $0.7 million of reduced operating costs as a result of the closure of the land-fill gas facilities in 2010, as compared to the same period in 2010. Operating expenses in the included costs of $0.4 million associated with the pursuit of various growth and development activities as compared to $0.5 million in the comparable period. The division reported decreased expenses of $0.5 million from U.S. operations as a result of the weaker U.S. dollar as compared to the same period in 2010.

For the year ended December 31, 2011, the Thermal Energy division's operating profit totalled $19.9 million, as compared to $16.9 million during the same period in 2010, representing an increase of $3.0 million or 18%. Operating profit in the Thermal Energy division exceeded expectations for the year ended December 31, 2011 as a result of improved operations at the EFW facility.

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, the business unit produced 126.5 GWhr of energy as compared to 120.6 GWhr of energy in the comparable period of 2010. During the quarter ended December 31, 2011, the business unit's total production increased by 8.0 GWhr from the Windsor Locks facility, partially offset by a decline of 1.6 GWhr from the Sanger facility, as compared to the same period in 2010.

The EFW facility processed 42,145 tonnes of municipal solid waste as compared to 43,535 tonnes of municipal solid waste in the same period of 2010. The current level of production resulted in the diversion of approximately 30,400 tonnes of waste from municipal solid waste landfill sites in the fourth quarter of 2011.

During the quarter ended December 31, 2011, the BCI and Windsor Locks facilities sold 310 billion lbs of steam as compared to 320 billion lbs of steam in the comparable period of 2010. During the quarter ended December 31, 2011, operations at the EFW facility generated 129 billion lbs of steam for the BCI facility as compared to 144 billion lbs of steam in the same period in 2010.

For the quarter ended December 31, 2011, energy / steam revenue in the Thermal Energy division totalled $10.6 million, as compared to $11.5 million during the same period in 2010, a decrease of $0.9 million, or 8%. As natural gas expense is a significant revenue driver and component of operating expenses, the division compares 'net energy sales revenue' (energy sales revenue less natural gas expense) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, net energy / steam sales revenue at the Thermal Energy division totalled $4.9 million, as compared to $6.0 million during the same period in 2010, a decrease of $1.1 million, primarily due to the Windsor Locks facility selling energy into the ISO-NE day-ahead market as compared to in 2010 when facility derived revenues from participating in the Forward Reserve Market. The decision to have the facility not participate in the Forward Reserve Market in 2011 was due to the fact that the facility could earn more selling into the ISO-NE day-ahead market compared to the lower prices offered for participating the Forward Reserve Market in 2011.

The decrease in revenue from energy / steam sales was primarily due to a decrease of $1.3 million at the Windsor Locks facility as a result of decreased energy rates, in part due to a lower average landed price per mmbtu for natural gas and the change in operating model of the facility, partially offset by an increase of $0.7 million at the Windsor Locks facility due to increased production and a net decrease of $0.1 million at the Sanger facility as a result of the change in energy pricing and production as compared to the same period in 2010. The natural gas expense at the Sanger and Windsor Locks facilities is discussed in detail below.

Revenue from waste disposal sales for the quarter ended December 31, 2011 totalled $4.0 million, as compared to $4.2 million during the same period in 2010.

For the quarter ended December 31, 2011, fuel costs at Sanger and Windsor Locks totalled $5.7 million, as compared with $5.5 million in the same period in 2010, an increase of $0.2 million. The overall natural gas expense at the Windsor Locks facility increased $0.2 million (5%), primarily the result of a 11% increase in volume of natural gas consumed, partially offset by a 5% decrease in the average landed cost of natural gas per mmbtu as compared to the same period in 2010. The average landed cost of natural gas at the Windsor Locks facility during the quarter was $4.75 per mmbtu. This was partially offset by a decrease in the natural gas expense at Sanger of $0.1 million (10%), primarily the result of a 8% decrease in the average landed cost of natural gas per mmbtu and a 2% decrease in the volume of natural gas consumed as compared to the same period in 2010. The average landed cost of natural gas at the Sanger facility during the quarter was U.S. $4.03 per mmbtu. The division reported increased fuel costs of $0.1 million as a result of the stronger U.S. dollar as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses, excluding fuel costs at Windsor Locks and Sanger, totalled $5.4 million, as compared to $5.5 million during the same period in 2010, a decrease of $0.1 million.

For the quarter ended December 31, 2011, the Thermal Energy division's operating profit totalled $4.0 million, as compared to $5.1 million during the same period in 2010, representing a decrease of $1.1 million or 22%. Operating profit in the Thermal Energy division met overall expectations for the quarter ended December 31, 2011.

Divisional Outlook – Thermal Energy

APCo's Thermal Energy division's Sanger facility will be offline during the majority of the first quarter of 2012 to accommodate certain transmission system upgrades being undertaken by PG&E and to allow for planned major maintenance. During this period capacity payments from PG&E will continue, however energy sales will be curtailed during this period. As a result, revenues from the Sanger facility are expected to be approximately $1.3 million lower than revenues achieved in the first quarter of 2011.

The Windsor Locks natural gas fired cogeneration facility will continue to sell a portion of its electricity capacity and all of its steam capacity to the industrial host with the balance of the electrical capacity available to be sold either into the ISO NE day-ahead market or to industrial customers through AES. It is anticipated that performance during the first quarter of 2012 will be in line with expectations.

APCo has commenced the repowering project at the Windsor Locks facility and has entered into an agreement with the steam host that extends the steam supply agreement to 2027. See *APCo Development Division – Windsor Locks* for further discussion on the repowering project.

The EFW facility is expected to continue to perform at throughput and operating costs levels in the first quarter of 2012 consistent with the results experienced in 2011. Pursuant to the waste supply agreement with the Region, the EFW facility charges an initial rate for a base 127,900 tonnes per year of acceptable municipal solid waste in a contract year and, once the base throughput levels are exceeded, the facility charges a lower rate for municipal solid waste received in the remainder of the contract year. The facility exceeded the base throughput levels as of the end of 2011 and, as a result, APCo anticipates lower revenue from waste disposal sales of approximately $0.5 million in the first quarter of 2012 as compared to the first quarter of 2011 as the tip fee charged during January and February will be at the lower rate.

The EFW facility "tip or pay" waste supply agreement with the Region expires in April 2012. On February 23, 2012, the Peel Regional Council decided to seek competitive proposals from several waste management companies, including APCo. APCo is participating in this proposal process. In addition, the facility is currently permitted to accept commercial and industrial waste from certain other jurisdictions outside of the Region of Peel. APCo is actively sourcing alternative supply options with respect to municipal solid waste from other jurisdictions to ensure a continued supply of waste for the facility.

APCo: Development Division

The Development division works to identify, develop and construct new power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APCo's existing facilities. The Development division is focused on projects within North America and is committed to working proactively with all stakeholders, including local communities. APCo's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a power purchase agreement, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that APCo will begin construction.

The Development division also creates opportunities through accretive acquisitions of operating assets and prospective projects that are at various stages of development.

Current Development Projects

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

Project Name (Location)	Location	Size (MW)	Estimated Capital Cost	Commercial Operation	PPA Term	Production GWhr
Chaplin Wind [1]	Saskatchewan	177	$355.0	2016	25	720.0
Amherst Island [2]	Ontario	75	$230.0	2014	25	247.0
Morse Wind [3, 4]	Saskatchewan	25	$70.0	2014	20	93.0
St. Damase [1]	Quebec	24	$70.0	2013	20	86.0
Val Eo [1]	Quebec	24	$70.0	2015	20	66.0
St. Leon II [1]	Manitoba	17	$30.0	2012	25	58.0
Cornwall Solar [1, 2]	Ontario	10	$45.0	2013	20	13.4
Total		**352**	**$870.0**			**1,283.4**

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

Chaplin Wind

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement with SaskPower for development of a 177 MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan.

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

Amherst Island Wind

The Amherst Island Wind Project is located on Amherst Island in the village of Stella, approximately 25 kilometres southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the OPA as part of the second round of the OPA's FIT program.

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

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

Morse Wind Project

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

APCo executed an asset purchase agreement with a local developer ("Kineticor") to acquire assets related to two adjacent 10 MW wind energy development projects in Saskatchewan and a further 5 MW was developed by APCo independently. All of the individual projects comprising the Morse Wind Project were selected by SaskPower for award of PPAs in accordance with the SaskPower Green Options Partners Program. The two 10 MW PPA's were awarded in May 2010 and the 5 MW PPA was awarded in June 2011. Upon SaskPower's approval and execution of the Kineticor PPAs, Kineticor will then assign the PPAs to APCo. All three of the projects are expected to be completed contemporaneously in early 2014.

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

Quebec Community Wind Projects

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

Saint-Damase

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

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

Val-Éo

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

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

St. Leon II

In July 2011, APCo executed a 25-year power purchase agreement with Manitoba Hydro in respect of St. Leon II (a 16.5 MW expansion of APUC's existing St. Leon wind energy project located in the Province of Manitoba). Construction of this project commenced on August 30, 2011 using 10 Vestas V82 turbines. The final turbine was erected in February 2012 and the project is generating energy on all units as of March 1, 2012. The project is expected to achieve commercial operation in the second quarter of 2012. The total capital cost of the project is expected to be $29.5 million.

Cornwall Solar

APCo entered into a share purchase agreement with EffiSolar Energy Corporation ("EffiSolar"), to acquire all of the issued and outstanding shares of Cornwall Solar Inc. based upon the achievement of specific milestones. On December 30, 2011 OPA approval was received and the transaction closed on January 4, 2012. Cornwall Solar owns the rights to develop a 10 MWac solar project located near Cornwall, Ontario. In addition to the Cornwall project, APCo has acquired an option to acquire 10 additional Ontario based solar projects. Projects in the FIT Pipeline have submitted Feed-in-Tariff applications for an additional 100MWac.

The Project has been granted an Ontario FIT contract by the OPA, with a 20 year term and a rate of $443/MWhr, resulting in expected initial annual revenues of approximately $6.2 million. The Project contemplates the use of a ground-mounted PV array system, with expected annual generation of approximately 13,400 MWh, enough to provide electricity to approximately 1,000 homes.

Following the completion of all regulatory submissions and approvals, construction of the project is expected to begin in the second half of 2012, with a Commercial Operation Date estimated in early 2013. The Project is being developed on two parcels of leased land totalling approximately 138 acres.

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

Windsor Locks Repowering

The Windsor Locks facility is a 56 MW natural gas powered electrical and steam energy generating station located in Windsor Locks, Connecticut. This facility delivers 100% of its steam capacity and a portion of its electrical generating capacity to Ahlstrom pursuant to an energy services agreement ("ESA").

APCo has entered into an extension of the ESA with Ahlstrom, the extended term continues until 2027, and supports the installation of a new 14 MW Solar Titan combustion gas turbine which is more appropriately sized to meet the electrical and steam requirements of the steam host. The new cogeneration equipment is in construction with commercial operation expected in July 2012. The total expected capital cost for this project is estimated at approximately U.S. $25 million. APCo believes it is eligible to receive a one-time non-recurring grant from the State of Connecticut equivalent to U.S. $450/KW to a maximum of U.S. $6.6 million which would offset the cost of such re-powering. An additional benefit of the State of Connecticut grant program is that local distribution charges for natural gas used by the new turbine are waived, with an estimated benefit to the Windsor Locks facility of approximately U.S. $500,000/year. In addition to installing the new gas turbine, APCo would expect to continue to operate the existing electrical generating equipment in the ISO NE market when it is commercially profitable to do so. APCo also believes that this project would qualify for a combined heat and power investment tax credit ("ITC") sponsored by the U.S. Federal Government. The benefit of the ITC grant is approximately U.S. $1 million in addition to the Connecticut DPUC grant would offset the cost of such re-powering.

Liberty Utilities
WATER | GAS | ELECTRIC

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

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

As the currently committed growth initiatives are completed, additional management regions will be created. Liberty Utilities (East) will be formed initially to deliver electrical and natural gas distribution services following the acquisition of Granite State and EnergyNorth. A fourth management region, Liberty Utilities (Central), will initially be created to manage the delivery of Liberty Utilities services in Missouri, Illinois and Iowa following the acquisition of certain gas distribution assets from Atmos.

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

Liberty Utilities (South)

Liberty Utilities (South) operates in Arizona, Texas, Missouri and Illinois and currently provides rate regulated water and wastewater utility services to approximately 76,000 customers in those states.

	Year ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Number of				
Wastewater connections			**36,750**	35,420
Wastewater treated (millions of gallons)			**2,000**	2,000
Water distribution connections			**38,750**	37,666
Water sold (millions of gallons)			**5,600**	5,500
	U.S. $	U.S. $	**Can $**	Can $
NBV of Assets for regulatory purposes (U.S. $)	**155,763**	155,258		
Revenue				
Wastewater treatment	**$ 23,295**	$ 20,202	**$ 23,031**	$ 20,935
Water distribution	**21,574**	15,877	**21,330**	16,453
Other Revenue	**636**	601	**628**	623
	$ 45,505	$ 36,680	**$ 44,989**	$ 38,011
Expenses				
Operating expenses	**(22,959)**	(21,371)	**(22,720)**	(22,199)
Other income	**482**	154	**488**	149
Divisional operating profit	**$ 23,028**	$ 15,463	**$ 22,757**	$ 15,961

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

Liberty Utilities (South) reports total connections, inclusive of vacant connections rather than customers. Liberty Utilities (South) had 36,750 wastewater connections as at December 31, 2011, as compared to 35,420 as at December 31, 2010, an increase of 1,330 in the period or 3.8%. Liberty Utilities (South) had 38,750 water distribution connections as at December 31, 2011, as compared to 37,666 as at December 31, 2010, representing an increase of 1,084 in the period or 2.8%. Total connections include approximately 1,800 vacant wastewater connections and 1,400 vacant water distributions connections as at December 31, 2011. Liberty Utilities (South)'s change in water distribution and wastewater treatment customer base during the period is primarily due to the acquisition of two small utilities in Missouri during the last quarter of 2011 and modest growth at Liberty Utilities (South)'s other facilities.

Liberty Utilities (South) has investments in regulatory assets of U.S. $155.8 million across four states as at December 31, 2011, as compared to U.S. $155.3 million as at December 31, 2010.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (South) provided approximately 5.6 billion U.S. gallons of water to its customers, treated approximately 2.0 billion U.S. gallons of wastewater and sold approximately 270 million U.S. gallons of treated effluent.

For the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $45.5 million as compared to U.S. $36.7 million during the same period in 2010, an increase of U.S. $8.8 million or 24%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state regulators over the past two years. Rate cases ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates.

Revenue from water distribution totalled U.S. $21.6 million as compared to U.S. $15.8 million during the same period in 2010, an increase of U.S. $5.7 million or 36%. The annual water distribution revenue was impacted, primarily due to the implementation of rate increases of U.S. $3.9 million at the Litchfield Park Service Company ("LPSCo") facility, U.S. $1.0 million at the Rio Rico facility and U.S. $0.8 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $23.3 million, as compared to U.S. $20.2 million during the same period in 2010, an increase of U.S. $3.1 million or 15%. The annual wastewater treatment revenue was impacted by increased revenue, primarily due to the implementation of rate increases of U.S. $2.8 million at the LPSCo facility and U.S. $0.4 million at the Black Mountain facility, partially offset by lower revenue at the Rio Rico facility of $0.4 million, as compared to the same period in 2010. In addition, revenue increased U.S. $0.4 million at seven wastewater treatment facilities, primarily due to customer increases at the Tall Timbers facility as compared to the same period in 2010.

For the year ended December 31, 2011, operating expenses totalled U.S. $23.0 million, as compared to U.S. $21.4 million during the same period in 2010, an increase of U.S. $1.6 million or 7%. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.5 million and U.S. $1.0 million related to increased wages, salary and other operating costs as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $23.0 million as compared to U.S. $15.5 million in the same period in 2010, an increase of U.S. $7.6 million or 49%. Liberty Utilities (South)'s operating profit exceeded expectations for the year ended December 31, 2011 due to increased customer counts and lower than expected power and operating labour costs.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $45.0 million as compared to $38.0 million during the same period in 2010, an increase of $7.0 million. Revenue from wastewater treatment totalled $23.0 million, as compared to $20.9 million during the same period in 2010, an increase of $2.1 million. Revenue from water distribution totalled $21.3 million, as compared to $16.5 million during the same period in 2010, an increase of $4.9 million. Liberty Utilities (South) reported decreased revenue from operations of $1.9 million in 2011 as a result of the weaker U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the year ended December 31, 2011, operating expenses totalled $22.7 million, as compared to $22.2 million during the same period in 2010, an increase of $0.5 million. Liberty Utilities (South) reported lower expenses from operations of $1.2 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the year ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $22.8 million as compared to $16.0 million in the same period in 2010, an increase of $6.8 million.

	Three months ended December 31		Three months ended December 31	
	2011	2010	2011	2010
Number of				
Wastewater treated (millions of gallons)			**500**	500
Water sold (millions of gallons)			**1,300**	1,400
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Wastewater treatment	**5,855**	5,543	**5,993**	5,649
Water distribution	**5,223**	4,074	**5,347**	4,152
Other Revenue	**123**	205	**126**	208
	$ 11,201	$ 9,822	**$ 11,466**	$ 10,009
Expenses				
Operating expenses	**(5,901)**	(5,264)	**(6,039)**	(5,370)
Other income	**229**	152	**224**	81
Divisional operating profit	**$ 5,529**	$ 4,710	**$ 5,651**	$ 4,720

2011 Fourth Quarter Operating Results

During the quarter ended December 31, 2011, Liberty Utilities (South) provided approximately 1.3 billion U.S. gallons of water to its customers, treated approximately 500 million U.S. gallons of wastewater and sold approximately 35 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled U.S. $11.2 million as compared to U.S. $9.8 million during the same period in 2010, an increase of U.S. $1.4 million or 14%. The increased revenues were primarily due to the implementation of rate increases from rate cases filed with state legislators over the past two years.

Revenue from water distribution totalled U.S. $5.2 million, as compared to U.S. $4.1 million during the same period in 2010, an increase of U.S. $1.1 million or 28%. The fourth quarter water distribution revenue increased primarily due to the implementation of rate increases of U.S. $0.6 million at the LPSCo facility, U.S. $0.3 million at the Rio Rico facility and U.S. $0.3 million at the Bella Vista facility as compared to the same period in 2010.

Revenue from wastewater treatment totalled U.S. $5.9 million, as compared to U.S. $5.5 million during the same period in 2010, an increase of U.S. $0.3 million or 6%. The fourth quarter wastewater treatment revenue increased primarily from the implementation of rate increases of U.S. $0.5 million at the LPSCo facility and U.S. $0.2 million at ten wastewater treatment facilities primarily due to increased customers as compared to the same period in 2010.

For the quarter ended December 31, 2011, operating expenses totalled U.S. $5.9 million, as compared to U.S. $5.3 million during the same period in 2010. Overall expenses increased U.S. $0.6 million or 12% as compared to the same period in 2010. Operating expenses increased due to increased utilities, consumable, property tax and insurance expenses of U.S. $0.1 million and U.S. $0.4 million related to wages, salary and other operating costs as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled U.S. $5.5 million as compared to U.S. $4.7 million in the same period in 2010, an increase of U.S. $0.8 million or 17%. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (South)'s revenue totalled $11.5 million, as compared to $10.0 million during the same period in 2010. Revenue from wastewater treatment totalled $6.0 million, as compared to $5.6 million during the same period in 2010, an increase of $0.3 million. Revenue from water distribution totalled $5.3 million, as compared to $4.2 million in the same period in 2010, an increase of $1.2 million. Liberty Utilities (South) reported increased revenue from operations of $0.1 million in the fourth quarter of 2011 as a result of the stronger U.S. dollar as compared to the same period in 2010.

Measured in Canadian dollars, for the quarter ended December 31, 2011, operating expenses totalled $6.0 million, as compared to $5.4 million during with same period in 2010, an increase of $0.6 million. Liberty Utilities (South) reported lower expenses from operations of $0.4 million as a result of the weaker U.S. dollar, as compared to the same period in 2010.

For the quarter ended December 31, 2011, Liberty Utilities (South)'s operating profit totalled $5.7 million as compared to $4.7 million in the same period in 2010, an increase of $0.9 million. Liberty Utilities (South)'s operating profit met expectations for the three months ended December 31, 2011.

Outlook – Liberty Utilities (South)

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

Revenue increases from rate cases at the Rio Rico facility and the Bella Vista facility completed in the first quarter of 2011 are anticipated to contribute moderate additional revenue in Liberty Utilities (South) in the first quarter of 2012 as compared to the same period in 2011. Liberty Utilities (South) attributes the majority of the revenue increases in the year ended December 31, 2011 to the impact of completed rate cases.

Liberty Utilities (West)

On January 1, 2011, APUC, in partnership with Emera, acquired the assets comprising the California Utility for a gross purchase price of approximately U.S. $136.1 million. Liberty Utilities owns 50.001% and Emera owns 49.999% of California Pacific Utility Ventures LLC, which owns 100% of the purchaser of the California Utility, California Pacific Electric Company ("Calpeco").

The acquisition of the California Utility was completed following receipt of all U.S. state and federal regulatory approvals. Contemporaneously with the closing, Emera exchanged previously announced subscription receipts into 8.532 million APUC common shares at a purchase price of $3.25 per share. The proceeds of the subscription receipts were utilized to fund Liberty Energy's share of the equity in acquisition of the California Utility.

The acquisition was also funded in part with the proceeds of a U.S. $70 million senior unsecured notes. The notes are a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate and split into two tranches, U.S. $45 million of ten year 5.19% notes maturing December 29, 2020 and U.S. $25 million of 5.59% fifteen year notes maturing December 29, 2025.

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

	Year ended December 31		Year ended December 31	
	2011	**2010**	**2011**	**2010**
Number of Customer Accounts				
Residential			41,346	-
Commercial – Small			5,506	-
Commercial – Large			54	-
Total Customer Accounts			**46,906**	
Customer Usage (GWhr)				
Residential			291.2	-
Commercial – Small			174.2	-
Commercial – Large			136.6	-
Total Customer Usage (GWhr)			**602.0**	
	U.S. $	U.S. $	**Can $**	Can $
Assets for regulatory purposes (U.S. $)	**155,843**	-		
Revenue				
Utility energy sales and distribution	**$ 78,125**	$ -	**$ 77,368**	$ -
Less:				
Cost of sales – Energy*	**(46,917)**	-	**(46,491)**	
Net utility energy sales	**$ 31,208**	$ -	**$ 30,877**	$ -
Expenses				
Operating expenses	**(16,142)**	-	**(16,019)**	-
Division operating profit**	**$ 15,066**	$ -	**$ 14,858**	$ -

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

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

As at December 31, 2011, Liberty Utilities (West) holds a 50.001% controlling interest in the California Utility. As the California Utility was acquired on January 1, 2011 there are no comparable results for 2010.

Liberty Utilities reports active connections, exclusive of vacant connections rather than total connections. Liberty Utilities (West) had approximately 41,300 residential electrical customer accounts and 5,550 commercial electrical customer accounts, as at December 31, 2011.

Liberty Utilities (West) has investments in regulatory assets of U.S. $155.8 million in California as at December 31, 2011.

2011 Annual Operating Results

During the year ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 602,000 MWhr of energy.

For the year ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $78.1 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are ultimately passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the year ended December 31, 2011, net utility energy sales revenue for Liberty Utilities (West) totalled U.S. $31.2 million.

For the year ended December 31, 2011, energy purchases for Liberty Utilities (West) totalled U.S $46.9 million. During the year ended December 31, 2011, the California Utility purchased approximately 602,000 MWhr of energy at rates averaging U.S. $77.9 per MWhr.

For the year ended December 31, 2011, operating expenses, excluding energy purchases, totalled U.S. $16.1 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $15.1 million. Liberty Utilities (West)'s operating profit did not meet expectations for the year ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by lower than budgeted property taxes and higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $77.4 million. For the year ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $30.9 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $46.5 million.

Measured in Canadian dollars, for the year ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $16.0 million.

For the year ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $14.9 million.

	Three months ended December 31		Three months ended December 31	
	2011	2010	2011	2010
Customer Usage (GWhr)				
Residential			69.4	-
Commercial – Small			50.4	-
Commercial – Large			40.4	-
Total Customer Usage (GWhr)			**160.2**	
	U.S. $	U.S. $	**Can $**	Can $
Revenue				
Utility energy sales and distribution	**$ 20,805**	$ -	**$ 21,287**	$ -
Less:				
Cost of Sales – Energy*	**(13,176)**	-	**(13,486)**	
	$ 7,629	$ -	**$ 7,801**	$ -
Expenses				
Operating expenses	**(5,126)**	-	**(5,243)**	-
Division operating profit**	**$ 2,503**	$ -	**$ 2,558**	$ -

* Cost of Sales – Energy consists of energy purchases. Under GAAP, in APUC's consolidated Financial Statements, these amounts are included in operating expenses.
** Represents 100% of investment in the California Utility.

2011 Fourth Quarter Operating Results

For the quarter ended December 31, 2011, Liberty Utilities (West)'s customer usage totalled approximately 160,100 MWhr of energy.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from utility energy sales totalled U.S. $20.8 million. The purchase of energy by the California Utility is a significant revenue driver and component of operating expenses but these costs are effectively passed through to its customers. As a result, the division compares 'net energy sales revenue' (energy sales revenue less energy purchases) as a more appropriate measure of the division's results. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net utility energy sales revenue totalled U.S. $7.6 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled U.S $13.2 million. During the quarter, the California Utility purchased approximately 160,100 MWhr of energy at rates averaging U.S. $82.3 per MWhr.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses, excluding energy purchases, totalled U.S. $5.1 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled U.S. $2.5 million. Liberty Utilities (West)'s operating profit did not meet expectations for the three months ended December 31, 2011 primarily due to higher than budgeted insurance, administration and distribution costs which include vegetation management and maintenance, partially offset by higher than budgeted net utility energy sales.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s revenue from energy sales totalled $21.3 million. For the quarter ended December 31, 2011, Liberty Utilities (West)'s net energy sales revenue totalled $7.8 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s energy purchases totalled $13.5 million.

Measured in Canadian dollars, for the quarter ended December 31, 2011, Liberty Utilities (West)'s operating expenses excluding energy purchases totalled $5.2 million.

For the quarter ended December 31, 2011, Liberty Utilities (West)'s operating profit totalled $2.6 million.

Outlook – Liberty Utilities (West)

Liberty Utilities (West) expects modest customer growth within its service territories in 2012. Liberty Utilities (West) anticipates that the California Utility should meet expectations for the first quarter of 2012.

On February 17, 2012, the California Utility filed a general rate case with the CPUC seeking, among other things, an increase of 10.0%, or $7.5 million in general rates, comprised of a $3.3 million increase in vegetation management costs, $13.0 million increase in distribution rates offset by reductions in commodity costs of $8.8 million. The California Utility's proposed procedural schedule contemplates rates to be implemented on January 1, 2013.

On April 29, 2011, Liberty Utilities announced it had reached an agreement with Emera to acquire the interest in the California Utility held by Emera. Emera agreed to sell its 49.999% direct ownership in the California Utility, with closing of such transaction subject to regulatory approval. As consideration Emera will receive 8.211 million APUC shares in two tranches; approximately half of the shares will be issued following regulatory approval of the California Utility ownership transfer (expected in 2012) and the balance of the shares will be issued following completion of the California Utility's first rate case, expected to be completed in early 2013.

Liberty Utilities (East)

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

Granite State provides electric service to over 43,000 customers in 21 communities in New Hampshire. EnergyNorth provides natural gas services to over 83,000 customers in five counties and 30 communities in New Hampshire.

The closing of the transaction is subject to approval by the NHPUC. Liberty Utilities is currently proceeding through the regulatory approval process. A series of technical sessions with the NHPUC have been held to review the merits of the transaction, identify key transitional issues and resolve issues raised by commission staff, the consumer advocate and other interveners. Liberty Utilities and National Grid are now working with the NHPUC Staff and Consumer Advocate to prepare a settlement recommendation to present to the Commissioners of the NHPUC for consideration and ultimate approval. The current regulatory hearing schedule should allow for a public hearing in late Q1 2012, with a commission decision expected shortly thereafter. This would likely to result in closing occurring towards the end of Q2 2012.

In connection with these acquisitions, Emera has committed to a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the transactions at a purchase price of $5.00 per share representing an approximate 5% premium to APUC's closing share price on December 8, 2010. The issuance of these subscription receipts is subject to regulatory approval.

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

Liberty Utilities (Central)

On May 13, 2011, Liberty Utilities (Central) entered into an agreement with Atmos to acquire the gas utilities located in Missouri, Iowa, and Illinois. Total purchase price for the gas utilities is approximately U.S. $124 million, plus working capital and subject to certain other closing adjustments. Liberty Utilities expects to acquire assets for rate making purposes of approximately U.S. $112 million, plus working capital and subject to certain other closing adjustments, representing a purchase price multiple of 1.106x. The gas utilities currently provide natural gas local distribution service to approximately 84,000 customers (57,000 in Missouri, 23,000 in Illinois, and 4,000 in Iowa).

The closing of the transaction is subject to approval by the MPSC, the IUB, and the ICC. Liberty Utilities has received approval from the IUB and has entered a unanimous stipulation with the MPSC. Liberty Utilities is currently proceeding through the regulatory approval process with the ICC which requires the company, Atmos and the ICC staff to review the merits of the transaction. A hearing on a limited set of issues was held in Illinois in January 2012, and a proposed ICC decision is expected in Q2 2012. Management expects closing to occur towards the end of Q2 2012.

Upon completion of the transaction, the results of these utilities will be reported in the Liberty Utilities (Central) division. It is expected that management responsibility for the rate regulated water utility systems located in

Missouri and currently reported in the results of Liberty Utilities (South) will be transferred to the newly formed Liberty Utilities (Central) following the acquisition of the Atmos assets.

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

APUC: Corporate

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	**2011 (millions)**	2010 (millions)
Corporate and other expenses:				
Administrative expenses and management costs	**4.8**	5.1	**17.5**	14.9
Write down of intangibles and property plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss / (Gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Interest expense	**7.6**	6.5	**30.4**	24.8
Interest, dividend and other Income	**(0.8)**	(1.0)	**(3.0)**	(3.6)
Loss / (Gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)

2011 Annual Corporate and Other Expenses

During the year ended December 31, 2011, management and administrative expenses totalled $17.5 million, as compared to $14.9 million in the same period in 2010. The expense increase in the year ended December 31, 2011 results from additional personnel, increased wages, additional costs required to administer APUC's operations, stock option expense, franchise taxes, a provision related to water lease dues at the Cote St.-Catherine facility and other costs as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1.3 million representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. The carrying value was written down to its fair value less cost to sell resulting in an impairment charge of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the expected sales price. In addition, Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes.

Subsequent to the year end, the Region elected not to extend the existing EFW waste processing contract and is seeking competitive proposals from several waste management companies, including EFW. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and APCo recognized an impairment charge on intangible assets of $13.4 million.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and recognized an impairment charge on property, plant and equipment of $1.8 million representing the difference between the carrying value of the assets and their fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities. The equipment was sold subsequent to December 31, 2010. The carrying value was written down to its fair value less cost to sell resulting in a loss of $0.7 million, which was included in earnings for the period. The fair value of the equipment was based on the sales price.

For the year ended December 31, 2011, interest expense totalled $30.4 million as compared to $24.8 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s senior unsecured notes and APCo's senior unsecured debentures compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures in April 2011, as compared to the same period in 2010.

For the year ended December 31, 2011, interest, dividend and other income totalled $3.0 million, as compared to $3.6 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

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

An income tax recovery of $23.0 million was recorded in the year ended December 31, 2011, as compared to a recovery of $20.8 million in the same period in 2010. There are two primary reasons for the income tax recovery for the period ended December 31, 2011. First, in the third quarter of 2011, APUC completed a capital structure project to ensure its operating subsidiaries have a capital structure that is appropriate for its business sector and that uses the functional currency in which it operates. Therefore as part of this process, APUC converted Canadian dollar denominated intercompany notes with a U.S. subsidiary of APCo into U.S. dollar denominated preferred shares resulting in a realized foreign exchange loss for tax purposes and a release of the valuation allowance associated with the unrealized foreign exchange loss accumulated to that point, thereby creating a future tax asset of approximately $15.6 million that is now available as additional tax shelter in future years. Secondly, on October 27, 2009, Algonquin effectively converted from a publicly traded income trust to a publicly traded corporation. Included in future income tax recoveries for the year ended December 31, 2011 is $6.6 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

2011 Fourth Quarter Corporate and Other Expenses

During the quarter ended December 31, 2011, management and administrative expenses totalled $4.8 million, as compared to $5.1 million in the same period in 2010. The expense decrease in the three months ended December 31, 2011 primarily results from decreased capital taxes, partially offset by the reasons discussed in "*2011 Annual Corporate and Other Expenses*" above as compared to the same period in 2010.

In December 2011, APCo wrote down its investment in a small hydro facility. Subsequent to the year end, APCo entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $0.2 million. Liberty Utilities (South) wrote down certain facility's assets in the amount of $1.1 million as a result of regulatory decisions in 2011 that deemed certain capital expenditures not allowable for rate-base purposes. Subsequent to the year end, EFW wrote off the remaining intangible assets associated with the existing waste management and energy contracts with the Region and recognized an impairment charge on intangible assets of $13.4 million. See the discussion in the annual corporate and other expenses section above for details related to this expense.

In the comparable period of 2010, APCo wrote down its investment in three small hydro facilities and the equipment at the Crossroads thermal facility in New Jersey. See the discussion in the annual corporate and other expenses section above for details related to this expense.

For the quarter ended December 31, 2011, interest expense totalled $7.6 million as compared to $6.5 million in the same period in 2010. Interest expense increased primarily as a result of higher levels of borrowings resulting from the acquisition of the California Utility and higher long term rates associated with Liberty Utilities (South)'s long term debt private placement compared to the short term rates that are associated with a short term bank credit facility. In addition, there was higher average variable interest expense, partially offset by lower average borrowings and the conversion of the Series 1A Debentures, as compared to the same period in 2010.

For the quarter ended December 31, 2011, interest, dividend and other income totalled $0.8 million, as compared to $1.0 million in the same period in 2010. Interest, dividend and other income primarily consists of dividends from APUC's share investment in the Kirkland and Cochrane facilities.

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

An income tax recovery of $6.6 million was recorded in the three months ended December 30, 2011, as compared to a recovery of $16.4 million in the same period a year ago. The income tax recovery for the three months ended December 31, 2011 results from those factors discussed in "*2011 Annual Corporate and Other Expenses"* above as compared to the same period in 2010. Included in future income tax recoveries for the three months ended December 31, 2011 is $1.2 million related to the recognition of deferred credits from the utilization of future income tax assets which were set up based on the new corporate structure on October 27, 2009.

Non-GAAP Performance Measures

Reconciliation of Adjusted EBITDA to net earnings

EBITDA is a non-GAAP metric used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of depreciation and amortization expense, income tax expense or recoveries, acquisition costs, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the company. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

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

	Three months ended December 31		Year ended December 31	
	2011	2010	**2011**	2010
	(millions)	(millions)	**(millions)**	(millions)
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add (deduct):				
Net earnings attributable to the non controlling interest	**0.5**	0.1	**3.9**	0.4
Income tax recovery	**(6.6)**	(16.4)	**(23.0)**	(20.8)
Interest expense	**7.6**	6.5	**30.4**	24.8
Acquisition Costs	**1.2**	2.3	**3.0**	3.0
Write down of intangibles, property, plant and equipment	**16.5**	2.5	**16.5**	2.5
Loss (gain) on derivative financial instruments	**1.6**	(1.8)	**5.8**	1.1
Loss (gain) on foreign exchange	**0.4**	(0.1)	**(0.7)**	(0.5)
Depreciation and amortization	**11.6**	12.1	**45.9**	46.6
Adjusted EBITDA	**$ 24.3**	$ 20.8	**$ 105.2**	$ 75.1

For the year ended December 31, 2011, Adjusted EBITDA totalled $105.2 million as compared to $75.1 million, a net increase of $30.1 million or 40% as compared to the same period in 2010. For the quarter ended December 31, 2011, Adjusted EBITDA totalled $24.3 million as compared to $20.8 million, a net increase of $3.5 million or 17% as compared to the same period in 2010.

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

	Three months ended December 31, 2011 (millions)	Year ended December 31, 2011 (millions)
Comparative Prior Period Adjusted EBITDA	$ 20.8	$ 75.1
Significant Changes:		
Acquisition of the California Utility	2.5	15.1
EFW facility	(0.4)	5.2
Liberty Utilities (South) revenue increases primarily due to rate case approvals	0.7	7.2
Hydro Renewable due to improved hydrology (reduced hydrology in Q4)	(0.5)	6.1
St. Leon - primarily due to an increased wind resource	1.6	3.0
Administration and management costs	0.3	(2.6)
Lower results from the weaker U.S. dollar (stronger in Q4)	1.2	(1.7)
Tinker Hydro / AES primarily due to lower energy demand	(0.2)	(1.0)
Windsor Locks – change in operating model	(0.4)	(1.9)
Other	(1.3)	0.7
Current Period Adjusted EBITDA	**$ 24.3**	**$ 105.2**

Reconciliation of adjusted net earnings to net earnings

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

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

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

	Three months ended December 31, 2011		**Year ended December 31, 2011**	
	2011	**2010**	**2011**	**2010**
	(millions)	**(millions)**	**(millions)**	**(millions)**
Net earnings attributable to Shareholders	**$ (8.5)**	$ 15.6	**$ 23.4**	$ 18.0
Add:				
Loss (gain) on derivative financial instruments, net of tax	**1.0**	(1.2)	**3.9**	0.7
Loss (gain) on foreign exchange, net of tax	**0.4**	(0.1)	**(0.7)**	(0.5)
Write down of intangibles, property, plant and equipment	**13.1**	2.5	**13.2**	2.5
Acquisition costs, net of tax	**0.7**	1.4	**1.8**	1.8
Adjusted net earnings	**$ 6.7**	$ 18.2	**$ 41.6**	$ 22.5
Adjusted net earnings per share	**$ 0.05**	$ 0.19	**$ 0.36**	$ 0.24

For the year ended December 31, 2011, adjusted net earnings totalled $41.6 million as compared to adjusted net earnings of $22.5 million, an increase of $19.1 million as compared to the same period in 2010. The increase in adjusted net earnings in the year ended December 31, 2011 is primarily due to increased earnings from operations, partially offset by increased interest and administrative expenses and lower recoveries of deferred taxes as compared to the same period in 2010.

For the three months ended December 31, 2011, adjusted net earnings totalled $6.7 million as compared to $18.2 million, a decrease of $11.5 million as compared to the same period in 2010. The decrease in adjusted net earnings in the three months ended December 31, 2011 is primarily due to increased interest and administrative expenses and reduced recoveries of deferred taxes, partially offset by increased earnings from operations as compared to the same period in 2010.

Summary of Property, Plant and Equipment Expenditures

	Three months ended December 31		Year ended December 31	
	2011 (millions)	2010 (millions)	2011 (millions)	2010 (millions)
APCo				
Renewable Energy Division				
Capital expenditures	**$ 6.7**	$ 1.0	**$ 25.6**	$ 2.3
Acquisition of operating entities	**-**	-	**-**	40.3
Total	**$ 6.7**	$ 1.0	**$ 25.6**	$ 42.6
Thermal Energy Division				
Capital expenditures	**$ 4.5**	$ 0.5	$ 13.6	$ 11.6
Total	**$ 4.5**	$ 0.5	**$ 13.6**	$ 11.6
LIBERTY UTILITIES				
South				
Capital Investment in regulatory assets	**$ 1.5**	$ 4.5	**$ 10.9**	$ 6.6
Acquisition of operating entities	**0.4**	-	**1.3**	2.1
Total	**$ 1.9**	$ 4.5	**$ 12.2**	$ 8.7
West				
Capital Investment in regulatory assets	**$ 4.9**	$ -	**$ 10.3**	$ -
Acquisition of operating entities	**1.4**	3.1	**98.7**	3.1
Total	**$ 6.3**	$ 3.1	**$ 109.0**	$ 3.1
Consolidated				
Total APCo				
Capital expenditures	$ 11.2	$ 1.5	**$ 39.2**	$ 13.9
Acquisition of operating entities	-	-	**-**	40.3
Total Liberty Utilities				
Capital investment in regulatory assets	$ 6.4	4.5	**$ 21.2**	6.6
Acquisition of operating entities	1.8	3.1	**100.0**	5.2
Corporate	0.1	0.1	**0.4**	0.2
Total	**$ 19.5**	$ 9.2	**$ 160.8**	$ 66.2

APUC's consolidated capital expenditures in the year ended December 31, 2011 increased as compared to the same period in 2010 primarily due to the acquisition of the California Utility, the start of the construction of St. Leon II and the Windsor Locks repowering project.

Property, plant and equipment expenditures for 2012 are anticipated to be between $60 million and $70 million, including approximately $14.0 million related to ongoing requirements by Liberty Utilities (South), $11.0 million at Liberty Utilities (West) related to the California Utility, $15.5 million related to the APCo Thermal division, primarily related to the Windsor Locks repowering and major maintenance at the Sanger facility, and $18.5 million related to the APCo Renewable Energy division, primarily related to the St. Leon II expansion and a major project at the Tinker facility.

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

2011 Annual Property Plant and Equipment Expenditures

During the year ended December 31, 2011, APCo incurred net capital expenditures of $39.2 million, as compared to $13.9 million during the comparable period in 2010. APCo also invested $40.3 million to acquire operating assets/entities during the comparable period in 2010.

During the year ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $25.6 million, as compared to $2.3 million in the comparable period in 2010. The St. Leon II development and the turbine overhaul project at the Tinker facility were the major individual projects initiated in the current period. The APCo Renewable Energy division's acquisition of operating assets in 2010 relate to the Tinker Assets located in New Brunswick and Maine. The APCo Thermal Energy division's net capital expenditures were $13.6 million, as compared to $11.6 million in the comparable period in 2010. The major expenditures in the year primarily relates to the Windsor Locks repowering project and investments at the Sanger facility. In the comparable period, the capital expenditures primarily relate to the EFW facility where major capital maintenance was underway.

During the year ended December 31, 2011, Liberty Utilities invested $21.2 million in regulatory assets, as compared to $6.6 million during the comparable period in 2010. These investments comprise of $10.9 million at Liberty Utilities (South) and $10.3 million at Liberty Utilities (West). Liberty Utilities also invested $100.0 million to acquire operating assets/entities, primarily related to Liberty Utilities (West)'s investment of $98.7 million to acquire the California Utility in 2011.

2011 Fourth Quarter Property Plant and Equipment Expenditures

During the quarter ended December 31, 2011, APCo incurred net capital expenditures of $11.2 million, as compared to $1.5 million during the comparable period in 2010.

During the quarter ended December 31, 2011, APCo Renewable Energy division's capital expenditures were $6.7 million, as compared to $1.0 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the St. Leon II development and the turbine overhaul project at the Tinker facility. The APCo Thermal Energy division's net capital expenditures were $4.5 million, as compared to $0.5 million in the comparable period in 2010. The major expenditures in the quarter primarily relates to the Windsor Locks repowering project and investments at the Sanger facility.

During the quarter ended December 31, 2011, Liberty Utilities invested $6.4 million, as compared to $4.5 million during the comparable period in 2010. These investments comprise of $1.5 million at Liberty Utilities (South) and $4.9 million at Liberty Utilities (West). During the quarter, Liberty Utilities (West) recorded an adjustment to the purchase price of the California Utility which reduced the purchase price by $1.4 million.

Dam Safety Legislation

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

APCo has spent approximately $1.5 million to date on dam safety evaluations, engineering, permitting and civil works related to the Bill C93 requirements. APCo currently estimates further capital expenditures of approximately $16.9 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years approximately as follows:

	Total	2012	2013	2014	2015
Estimated future Bill C-93 Capital Expenditures	**16,900**	1,100	5,300	7,700	2,800

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

- The dam safety evaluation for the Mont Laurier facility was completed in 2008 and APCo's proposed remediation plan has now been accepted by the Quebec government. APCo has been performing engineering and permitting since 2010 and received the Certificate of Authorization from the Quebec government in November 2011. APCo anticipates completing the on-site remediation work in 2012.
- In respect of the Donnacona facility, APCo completed the dam safety evaluation in 2007 and has been investigating alternative engineering designs to minimize the cost of the remediation work. APCo is now pursuing a design that may result in a cost savings of 20% of the original estimates. APCo anticipates completing the engineering in 2012 and performing the remedial work in 2013 and 2014.

- The dam safety study for the St. Alban facility was completed in 2010 followed by a detailed condition assessment in 2011. APCO will review the results of the condition assessment and finalize the remediation plan for this dam in 2012. APCo anticipates engineering and regulatory review to be performed in 2012 and 2013, with remedial work in 2014 to 2015.
- APCo is presently reviewing options with respect to the Belleterre facility including the removal of several small dams that are not required for power generation. APCo has been corresponding with the Quebec government and other stakeholders about these options since 2007. APCo anticipates completion of any required work on these dams by 2015.
- The dam remediation work related to Chute Ford will be completed in 2012 while the work related to the St. Raphael and Riviere-du-Loup facilities is anticipated to be completed in 2013. No dam remediation work is required at the Arthurville, Hydraska, and Ste-Brigitte facilities.
- The dam remediation work related to the Rawdon facility was completed in 2011.

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

LIQUIDITY AND CAPITAL RESERVES

The following table sets out the amounts drawn, letters of credit issued and outstanding amounts available to APUC and its subsidiaries as at December 31, 2011 under the Facility:

	2011 Q4 (millions)	2011 Q3 (millions)	2011 Q2 (millions)	2011 Q1 (millions)	2010 Q4 * (millions)
Committed and available Facility	$ 120.0	$ 120.0	$ 142.0	$ 142.0	$ 142.0
Funds Drawn on Facility	-	(12.0)	(70.0)	(65.0)	(64.5)
Letters of Credit issued	(39.6)	(40.1)	(32.5)	(32.9)	(33.1)
Remaining available Facility	**$ 80.4**	**$ 67.9**	**$ 39.5**	**$ 44.1**	**$ 44.4**
Cash on Hand	72.9	15.5	8.7	2.5	**4.7**
Total liquidity and capital reserves	**$ 153.3**	**$ 83.4**	**$ 48.2**	**$ 46.6**	**$ 49.1**

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

During the first quarter, APCo concluded negotiations with its bank syndicate on the renewal of the Facility for a three year term with a maturity date of February 14, 2014. Algonquin also reduced the total of the Facility to $120 million following the completion of the Senior Unsecured Debenture offering of APCo in July 2011. As at December 31, 2011, no amounts had been drawn on the Facility as compared to $64.5 million as at December 31, 2010. In addition to amounts actually drawn, there were $39.6 million in letters of credit outstanding as at September 30, 2011. APCo had $80.4 million of committed and available bank facilities remaining and $72.9 million of cash resulting in $153.3 million of total liquidity and capital reserves.

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

On October 27, 2011, APUC completed an equity offering of $85.3 million, a portion of the net proceeds of which have been used to repay the outstanding balance on the Facility. On November 14, 2011, the underwriters exercised a portion of the over-allotment option granted with the Offering and an additional 1,769,000 common shares were issued on the same terms and conditions of the Offering. As a result, APUC issued 16,869,000 common shares under the Offering for the total gross proceeds of approximately $95.3 million.

On January 19, 2012, Liberty Utilities announced that it had entered into an agreement for a U.S. $80 million senior unsecured revolving credit facility (the "Liberty Facility") with a three year term. Initially, U.S. $25 million will be available immediately to support the operations of Liberty Utilities and its current subsidiaries. The additional U.S. $55 million will be automatically available to Liberty Utilities to support operations and working capital requirements of all committed regulated utility acquisitions following the closing of the previously announced acquisition of Granite State and EnergyNorth. The Liberty Facility includes provisions which allow the available credit to be increased to accommodate future working capital needs or other requirements.

APUC intends to use its liquidity and capital reserves to fund announced capital expansion projects in APCo and to partially fund announced share acquisitions in Liberty Utilities.

CONTRACTUAL OBLIGATIONS

Information concerning contractual obligations as of December 31, 2011 is shown below:

	Total	Due less than 1 year	Due 1 to 3 years	Due 4 to 5 years	Due after 5 years
	(millions)	(millions)	(millions)	(millions)	(millions)
Long-term debt obligations[1]	$ 332.7	$ 1.6	$ 3.7	$ 16.5	$ 310.9
Convertible debentures[2]	$ 122.3	-	-	59.7	62.6
Interest on long-term debt obligations	$ 227.9	25.6	40.2	37.3	124.8
Long term service agreements	$ 94.4	4.6	8.2	8.6	73.0
Purchased power	$ 227.5	45.1	91.5	90.9	-
Accounts payable/purchase obligations	$ 57.3	57.3	-	-	-
Capital Projects	$ 7.9	7.9	-	-	-
Energy forward purchase contract	$ 1.2	0.8	0.4	-	-
Interest rate swap	$ 6.9	2.1	3.7	1.1	-
Lease obligations	$ 2.7	1.2	1.2	0.3	-
Other obligations	$ 9.8	1.1	0.5	0.5	7.7
Total obligations	$ 1,090.6	$ 147.3	$ 149.4	$ 214.9	$ 579.0

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

[2] Convertible debentures include the Series 2A Debentures which were redeemed for equity effective February 24, 2012.

SHAREHOLDER'S EQUITY AND CONVERTIBLE DEBENTURES

The shares of APUC are publicly traded on the Toronto Stock Exchange ("TSX"). As at December 31, 2011, APUC had 136,122,780 issued and outstanding shares. Following the Series 2A Redemption, APUC had 146,741,635 shares outstanding.

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 December 31, 2011, APUC does not have any issued and outstanding preferred shares.

As at December 31, 2011, APUC had issued to Emera a treasury subscription of subscription receipts convertible into 12.0 million APUC common shares upon closing of the Granite State and EnergyNorth transactions at a purchase price of $5.00. Delivery of the shares under the subscription receipts is conditional on and is planned to occur simultaneously with the closing of the acquisition of Granite State and EnergyNorth. The proceeds of the subscription receipts are to be utilized to fund a portion of the cost to acquire Granite State and EnergyNorth.

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

On April 30, 2011, APUC committed to issuance to Emera of a treasury subscription of subscription receipts convertible into approximately 6.9 million APUC common shares upon closing of the transaction related to the acquisition of an interest in a portfolio of 370MW wind projects. This treasury subscription was terminated when APCo announced on January 27, 2012 that it no longer intended to proceed with the First Wind acquisition.

On April 7th, 2011, APUC provided the holders of its Series 1A Debentures with notice of its intention to redeem for equity, all of the issued and outstanding Series 1A Debentures. Prior to the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On the Redemption Date, APUC issued and delivered 430,666 APUC shares to the remaining holders of the Series 1A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures, by 95% of the current market price of APUC shares on the Redemption Date. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

Subsequent to December 31, 2011, on January 20, 2012, APUC provided the holders of its Series 2A 6.35% convertible unsecured subordinated debentures due November 30, 2016 ("Series 2A Debentures") notice of its intention to redeem for equity, effective February 24, 2012 ("Series 2A Redemption Date"), all of the issued and outstanding Debentures. Prior to the Series 2A Redemption Date, a principal amount of $2,916 of Series 2A Debentures were converted into 485,998 shares of APUC.

On the Series 2A Redemption Date, APUC issued and delivered 9,836,520 APUC shares to the remaining holders of Series 2A Debentures, representing the number of freely tradeable APUC shares obtained by dividing the aggregate principal amount of Debentures of $57,041, by 95% of the current market price of APUC shares on the Series 2A Redemption Date. As a result, there are no Series 2A Debentures outstanding subsequent to the Series 2A Redemption Date.

On December 2, 2009, APUC issued 63,250 convertible unsecured debentures at a price of $1,000 for each debenture maturing on June 30, 2017 (“Series 3 Debentures”). The Series 3 Debentures bear interest at 7.0% per annum, payable semi-annually in arrears on June 30 and December 30 each year, and are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares for each $1,000 principal. The Series 3 Debentures may not be redeemed by APUC prior to December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 Debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 Debentures’ maturity, APUC can redeem the Series 3 Debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 Debentures with additional shares.

On December 31, 2011, there were 62,571 Series 3 Debentures outstanding with a face value of $62,571.

During the three months ended December 31, 2011, a principal amount of $129 Series 3 Debentures were converted into 30,710 shares APUC. During the year ended December 31, 2011, a principal amount of $334 Series 3 Debentures were converted into 79,517 shares APUC. Subsequent to the end of the quarter, $66 Series 3 Debentures were converted to 15,711 shares.

SHARE BASED COMPENSATION PLANS

For the year ended December 31, 2011, APUC recorded $0.7 million (2010 - $0.1 million) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1.2 million and $0.1 million respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

STOCK OPTION PLAN

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

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

- On March 22, 2011, 892,107 options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $5.23;
- On June 21, 2011, 171,642 options were granted to a senior executive of APCo which allow for the purchase of common shares at a price of $5.64;

- On July 28, 2011, 90,909 options were granted to a senior executive of APUC which allow for the purchase of common shares at a price of $5.74; and
- On September 13, 2011, 172,242 options were granted to a senior executive of Liberty Utilities which allow for the purchase of common shares at a price of $5.68.

Subsequent to year end on March 14, 2012, 1,194,606 options were granted which allow for the purchase of common shares at a price of $6.22.

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

During the year ended December 31, 2011, no options were exercised. As at December 31, 2011, APUC had 2,487,104 options issued and outstanding. APUC determines the fair value of options granted using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on a straight-line basis over the options' vesting periods while ensuring that the cumulative amount of compensation cost recognized at least equals the value of the vested portion of the award at that date.

As at December 31, 2011, 386,735 options with an intrinsic value of $917 are exercisable. No share options were exercised in 2011 or 2010. The intrinsic value of the 2,487,104 options as at December 31, 2011 was $4,134.

PERFORMANCE SHARE UNITS

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

DIRECTORS DEFERRED SHARE UNITS

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one APUC common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC expects to settle these instruments in cash, these DSUs will be accounted for as liability awards. The DSU liabilities will be marked-to-market at the end of each period based on the common share price at the end of the period.

As at December 31, 2011, no DSUs had been issued.

EMPLOYEE SHARE PURCHASE PLAN

In September 2011, APUC approved an employee share purchase plan ("ESPP"). Eligible employees may have a portion of their earnings withheld to be used to purchase common shares of APUC. APUC will match up to 20% of an employee's contribution amount for the first $5,000 contributed annually and 10% of an employee's contribution amount for contributions over $5,000 and up to $10,000 annually. Shares purchased through the APUC match portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at time of issue or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. As at December 31, 2011, a total of 7,176 shares had been issued under the ESPP. For the three and twelve month period ended December 31, 2011, APUC recorded $9 in compensation expense.

DIVIDEND REINVESTMENT PLAN

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

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

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

As at December 31, 2011, 23.6 million common shares had been registered with the Reinvestment Plan.

MANAGEMENT OF CAPITAL STRUCTURE

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

APUC's objectives when managing capital are:

- To maintain its capital structure consistent with investment grade credit metrics appropriate to the sectors in which APUC operates;
- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital;
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets;
- To ensure generation of cash is sufficient to fund sustainable dividends to shareholders as well as meet current tax and internal capital requirements;
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders; and
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

APUC monitors its cash position on a regular basis to ensure funds are available to meet current normal as well as capital and other expenditures. In addition, APUC continuously reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

RELATED PARTY TRANSACTIONS

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

- APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for the three and twelve months ended December 31, 2011 were $82 and $327, respectively (2010 - $82 and $327). Based on a review of the real estate leasing market at the time, APUC believes the lease was entered into on terms equivalent to fair market value for prime office space of similar size and quality.

- APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the three and twelve months ended December 31, 2011, APUC incurred costs in connection with the use of the aircraft of $103 and $453, respectively (2010 - $60 and $430) and amortization expense related to the advance against expense reimbursements of $69 and $274, respectively (2010 - $13 and $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

- Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a five year period commencing two years after the commercial operation date of the facility of June 17, 2006, increasing by 2.5% every 5 years to a maximum of 10%. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $106 and $314 for the three and twelve months ended December 31, 2011 (2010 - $77 and $266).

- APMI is one of the two original developers of Red Lily I and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.

- Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") an entity where Senior Executives hold equity interests. APUC and APS had agreed to provide some transition services to each other until December 31, 2011. This agreement has been extended for an additional year in relation to one of the hydroelectric generating facilities. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.

- As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.

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

- In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During the three and twelve months ended December 31, 2011 APUC paid U.S. $73 and $260 (2010 - $64 and $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

- On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). During the three and twelve months ended December 31, 2011, AES sold electricity to MPS amounting to $1,263 and $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

- In 2008, APUC entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and APUC issued equity to the Highground shareholders and CJIG, in exchange for $26.2 million cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

- As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of the costs related to the California Utility.
- Long Sault is a hydroelectric generating facility in which APUC acquired its interest in the facility by way of subscribing to two notes from the original developers. An affiliate of APMI is one of the original partners in the facility and is entitled to receive 5% of the after tax equity cash flows commencing in 2014.
- APUC believes that the transactions noted above were in accordance with normal commercial terms. The above related party transactions have been recorded at the exchange amounts agreed to by the parties to the transactions.

Business Associations with APMI and Senior Executives.

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

The co-owned assets and remaining business associations as at December 31, 2011 are listed below. Subsequent to December 31, 2011, APUC and the Parties reached an agreement to resolve a number of the business associations and relationships (the "Agreement"). A more detailed description of the Agreement has been set out below in S*ettlement of Other Business Associations*.

i) Rattlebrook hydroelectric generating facility

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

ii) St. Leon wind power generating facility

St. Leon is a 104 MW wind power generating facility which has issued Class B units to external parties and Senior Executives. APUC and the Class B unit holders have simplified the relationship by amalgamating the previous partnership agreement and two amending agreements into an amended and restated agreement. In addition, APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

iii) Brampton Cogeneration Inc.

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

iv) *Long Sault Rapids hydroelectric generating facility*

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

v) *Chartered aircraft*

APUC utilizes chartered aircraft owned by an affiliate of APMI. APUC entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements. At December 31, 2011, $279 of the advance remained. The Board has undertaken an independent review of the relationship and believes that continuing the original arrangement is beneficial to the company. The current arrangement is expected to end in approximately 2016 when the advance will be fully utilized.

vi) *Office lease*

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

vii) *Operations services*

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities where Senior Executives hold an interest. Effective January 1, 2011, management of these facilities is now being undertaken by an affiliate of APMI. APUC and the APMI affiliate had agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up for profit. APUC agreed to provide supervisory management on a cost recovery basis for one of the facilities until December 31, 2012 to provide sufficient time for APMI to make alternative arrangements to manage the facility.

viii) *Sanger construction management*

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

ix) *Clean Power Income Fund*

During 2007, Algonquin allowed its offer to acquire Clean Power Income Fund ("Clean Power") to expire and earned a termination fee of $1.8 million. As part of its role in the process, APUC has agreed to pay APMI a fee of $0.1 million. As of December 31, 2011 this amount is accrued and included in accounts payable on the consolidated balance sheet. This liability was settled pursuant to the Agreement.

x) *Red Lily I*

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

xi) Trafalgar

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

Settlement of Other Business Associations.

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

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

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

TREASURY RISK MANAGEMENT

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

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

Foreign currency risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 55% of EBITDA in 2012 and 65% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $5.4 million ($0.05 per share) on an annual basis.

APUC manages this risk primarily through the use of natural hedges by using U.S. long term debt to finance its U.S. operations. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes.

Market price risk

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

Credit/Counterparty risk

APUC and its subsidiaries are subject to credit risk through its trade receivables, net receivable and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APUC does not believe this risk to be significant as approximately 82% of APCo Renewable Energy division's revenue, approximately 48% of APCo Thermal Energy division's revenue, and over 68% of APCo's total revenue is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

The following chart sets out APCo's significant counterparties, their credit ratings and percentage of total revenue associated with the counterparty:

Counterparty	Credit Rating *	Approximate Annual Revenues	Percent of Divisional Revenue
Renewable Energy Division			
Hydro – Quebec	A+	23,200	26%
Manitoba Hydro	AA	22,400	25%
Ontario Electricity Financial Corporation	A+	11,000	12%
MPS**	BBB+	6,600	7%
TransAlta Corp – Dickson Dam	BBB	4,000	5%
Public Service Company of New Hampshire	BBB	3,200	4%
National Grid	A-	3,000	3%
Total		**$ 73,400**	**82%**
Thermal Energy Division			
Regional Municipality of Peel	AAA	16,400	25%
Pacific Gas and Electric Company	BBB+	14,600	23%
Total		**$ 31,000**	**48%**

* Ratings by Dunn & Bradstreet or Standard & Poor's as of February 2012.
** MPS is a subsidiary of Emera.

The remaining revenue is primarily earned by Liberty Utilities. In this regard, the credit risk related to Liberty Utilities (South) accounts receivable balances of U.S. $5.1 million is spread over approximately 76,000 customers, resulting in an average outstanding balance of approximately $70.00 per customer. Liberty Utilities (West) has accounts receivable balances of U.S. $14.2 million with over 50% of revenue generated by residential customers.

Interest rate risk

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

- The Facility has no amounts outstanding as at December 31, 2011. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.

- APCo's project debt at the St. Leon facility had a balance of $67.8 million as at June 30, 2011. The outstanding balance was repaid during the quarter ended September 30, 2011 using proceeds from the Senior Unsecured Debenture offering. Accordingly there is no further interest rate risk associated with this debt facility.

- APCo's project debt at its Sanger cogeneration facility has a balance of U.S. $19.2 million as at December 31, 2011. Assuming the current level of borrowings over an annual basis, a 100 basis point change in the variable rate charged would impact interest expense by U.S. $0.2 million annually.

- APCo's project debt at Long Sault, Chute Ford and its $135 million senior unsecured debentures bear fixed rates of interest and are not subject to interest rate risk.

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

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

Liquidity risk

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

APUC currently pays a dividend of $0.28 per share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements and to fund working capital that, in its judgment, ensure APUC's long-term success. Based on the level of dividends paid during the year ended December 31, 2011, cash provided by operating activities exceeded dividends declared by 2.1 times.

As at December 31, 2011, APUC had cash on hand of $72.9 million and $80.4 million available to be drawn on the Facility. APUC reduced its level of short-term borrowings through the renewal of the Facility on February 14, 2011 for a three year term and through a U.S. $50 million private placement debt financing at Liberty Utility (South) on December 22, 2010. On July 25, 2011, APCo completed a private placement offering of the Senior Unsecured Debentures with a principal amount of $135 million. Net proceeds from the debentures were used to repay the project debt on APCo's AirSource senior debt financing which would have matured on October 2011, and to reduce amounts outstanding under APCo's senior credit facility. See the *Liquidity and Capital Reserves* section for a more detailed discussion and chart of the funds available to APUC and its subsidiaries under the Facility.

The long term portion of Facility and project specific debt total approximately $331.1 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facility and project debt with borrowings having less favourable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted. APUC attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps.

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

Commodity price risk

APCo's exposure to commodity prices is primarily limited to exposure to natural gas price risk. Liberty Water is not subject to any material commodity price risk. In this regard, a discussion of this risk is set out as follows:

- APCo's Sanger facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million on an annual basis.

- APCo's Windsor Locks facility's ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to Ahlstrom. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $1.4 million on an annual basis.

- APCo's BCI facility's energy services agreement includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per mmbtu, based on expected production levels, would result in an increase in net revenue by approximately $0.1 million.

- AES provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 130,000 MW-hrs in fiscal 2012. While the Tinker facility is expected to provide the majority of the energy required to service these customers, AES anticipates having to purchase a portion of its energy requirements at the ISO-NE spot rates to supplement self-generated energy. In the event that AES was required to purchase all of its energy requirements at ISO-NE spot rates, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $1.3 million on an annualized basis.

  This risk is mitigated through the use of short-term financial energy hedge contracts. AES has committed to acquire approximately 70,000 MW-hrs of net energy over the next 12 months at an average rate of approximately U.S. $50 per MW-hr. The mark-to-market value of these forward energy purchase contracts at December 31, 2011 was a net liability of U.S. $1.2 million.

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

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

OPERATIONAL RISK MANAGEMENT

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

There are a number of risk factors relating to the business of APUC and its subsidiaries. Some of these risks include the dependence upon APUC businesses, regulatory climate and permits, tax related matters, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that APUC and its subsidiaries may encounter. A more detailed assessment of APUC's business risks is also set out in the most recent AIF.

Mechanical and Operational Risks

APUC is entirely dependant upon the operations and assets of APUC's businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. The water distribution networks of Liberty Utilities operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property. The electricity distribution systems owned by Liberty Utilities are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

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

Regulatory Risk

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

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

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

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

Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases and other agreements, the probability of the agreements being extended, the likelihood of being required to incur such costs in the event there is an option to require decommissioning in the agreements, the ability to quantify such expense, the timing of incurring the potential expenses as well as business and other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

Liberty Utilities' facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, Liberty Utilities has regular maintenance programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These maintenance expenses, expenses associated with replacing aging distribution facilities and expenses associated with providing new sources of commodity supply can generally be included in the facility's rate base and thus Liberty Utilities expects to be allowed to earn a return on such investment.

Based on its assessments, APUC's businesses do not have any significant retirement obligation liabilities and APUC has not recorded any liability in its consolidated financial statements as at December 31, 2011.

Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

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

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

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable. There are no known material environmental liabilities as at December 31, 2011.

Cycles and Seasonality

The hydroelectric operations of APCo are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

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

At Liberty Utilities (South), demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

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

Litigation risks and other contingencies

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

APCo owns debt on seven hydroelectric facilities owned by Trafalgar. In 1997, an affiliate of APMI moved to foreclose on the assets, and subsequently Trafalgar went into bankruptcy. Trafalgar, APUC and an affiliate of APMI are involved in litigation over, among other things, a civil proceeding on the foreclosure on the assets and in bankruptcy proceedings. For additional comments on this matter, see *"Business Associations with APMI and Senior Executives - Trafalgar"*.

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

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

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $4.8 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, APCo accrued $1.0 million of water lease owed to Québec AG for 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $0.3 million were also recorded in 2011.

Obligations to serve

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

Disclosure Controls

At the end of the fiscal year ended December 31, 2011, APUC carried out an evaluation, under the supervision of and with the participation of the APUC's management, including the Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"), of the effectiveness of the design and operations of 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 December 31, 2011, APUC's disclosure controls and procedures are effective.

Internal controls over financial reporting

APUC's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of APUC; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. generally accepted accounting principles, and that receipts and expenditures of APUC are being made only in accordance with authorizations of management and directors of APUC; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of APUC's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management conducted an evaluation of the design and operation of APUC's internal control over financial reporting as of December 31, 2011 based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. This evaluation included review of the documentation of controls, evaluation of the design effectiveness of controls, testing of the operating effectiveness of controls and a conclusion on this evaluation. Based on this evaluation, management has concluded that APUC's internal control over financial reporting was effective as of December 31, 2011.

During the year ended December 31, 2011, there has been no change in APUC's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, APUC's internal control over financial reporting. There was no significant impact of the transition to U.S. GAAP on APUC's internal controls, information technology systems and financial reporting expertise requirements. No financial covenants were impacted by APUC's conversion to U.S. GAAP.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2011.

Millions of dollars (except per share amounts)	1st Quarter 2011	2nd Quarter 2011	3rd Quarter 2011	4th Quarter 2011
Revenue	$71.7	$66.8	$66.0	$72.1
Net earnings /(loss)	5.0	7.3	19.6	(8.5)
Net earnings / (loss) per share	0.05	0.07	0.16	(0.07)
Total Assets	1,175.8	1,177.7	1,263.1	1,282.6
Long term debt*	461.0	530.0	558.9	463.8
Dividend declared per share	0.065	0.065	0.07	0.07
	1st Quarter 2010*	**2nd Quarter 2010***	**3rd Quarter 2010***	**4th Quarter 2010**
Revenue	$ 45.9	$ 42.7	$ 45.4	$48.4
Net earnings / (loss)	3.5	(2.2)	1.5	15.6
Net earnings / (loss) per share	0.04	(0.02)	0.02	0.17
Total Assets	966.2	983.2	969.4	1,016.9
Long term debt*	434.0	446.7	452.8	450.8
Dividend declared per share	0.06	0.06	0.06	0.06

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

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

Quarterly revenues have fluctuated between $42.7 million and $72.1 million over the prior two year period. A number of factors impact quarterly results including acquisitions, seasonal fluctuations, hydrology and winter and summer rates built into the PPAs. In addition, a factor impacting revenues year over year is the fluctuation in the strength of the Canadian dollar which can result in significant changes in reported revenue from U.S. operations.

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

Critical Accounting Estimates and Polices

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 and fair value of derivatives. Actual results may differ from these estimates.

APUC's significant accounting policies are discussed in Note 1 to the consolidated financial statements. Management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates have been reviewed and discussed with the Audit Committee of the Board of Directors of APUC.

Estimated useful lives and recoverability of Long-Lived Assets and Intangibles

The provisions for depreciation of utility property and equipment for financial reporting purposes are made on the straight-line method based on the estimated service lives of the assets (3 to 75 years). Depreciation rates on utility assets are subject to regulatory review and approval, and depreciation expense is recovered through rates set by ratemaking authorities. The recovery of those costs is dependent on the ratemaking process. Non-regulated property and equipment are depreciated on a straight-line basis over useful lives (3 to 60 years) of the related assets. Management believes the lives and methods of determining depreciation are reasonable, however, changes in economic conditions affecting the industries could result in a reduction of the estimated useful lives of those non-regulated assets or in an impairment write-down of the carrying value of these properties.

The carrying value of long-lived assets, including identifiable intangibles, is reviewed whenever events or changes in circumstances indicate that such carrying values may not be recoverable. Some of the factors APUC considers as indicators of impairment include whether a facility is operating, its plan for return to service, external influences such as natural disasters, energy pricing and profitability and changes in regulation. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows, interest rates, regulatory matters and operating costs could negatively affect the fair value of APUC's assets and result in an impairment charge.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Valuation of Deferred Tax Assets

Income taxes are accounted for using the asset and liability method. Under this method, deferred income taxes are recognized, at currently enacted income tax rates, to reflect the tax effect of temporary differences between the financial and tax basis of assets and liabilities, as well as operating loss and tax credit carryforwards. The amount of deferred tax assets recognized is limited to the amount of the benefit that is more likely than not to be realized.

In assessing the realization of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized and provides any necessary valuation allowances as required. Although management believes the assumptions, judgments and estimates are reasonable, changes in tax laws and changes in operations could significantly impact the amounts provided for income taxes in our financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. This accounting guidance is applied to Liberty Utilities' operations. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and industry practice. If events were to occur that would make the recovery of these assets and liabilities no longer probable, these regulatory assets and liabilities would be required to be written off or write down. At December 31, 2011, APUC had recorded regulatory assets of $5.0 million and regulatory liabilities of $21.7 million.

Unbilled Energy Revenues

Revenues related to electricity and water delivery are generally recognized upon delivery to customers. The determination of customer billings is based on a systematic reading of meters throughout the month. At the end of each month, amounts of energy or water provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings. Historically, any differences between the actual and estimated amounts have been immaterial.

Derivatives

APUC uses derivative instruments to manage exposure to changes in electricity prices and interest rates. Derivative instruments that do not meet the normal purchases and sales exception are recorded at fair value, with changes in the derivative's fair value recognized currently in earnings. Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal purchases and sales exception applies or whether individual transactions qualify for hedge accounting treatment. Management's judgment is also required to determine the fair value of derivative transactions. APUC determines the fair value of derivative instruments based on forward market prices in active markets adjusted for nonperformance risk. A significant change in estimate could affect APUC's results of operations.

Additional disclosure of APUC's critical accounting estimates is also available SEDAR at www.sedar.com and on the APUC website at www.AlgonquinPowerandUtilities.com.

Changes in Accounting Policies

Accounting Framework

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

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

APUC has retrospectively adopted U.S. GAAP as its financial reporting accounting framework starting in 2011. U.S. GAAP reporting is permitted by Canadian securities laws and for companies listed on the TSX which are subject to reporting obligations under U.S. securities laws as an alternative to adoption of International Financial Reporting Standards ("IFRS"). APUC has concluded that U.S. GAAP is the accounting framework that provides its shareholders and other readers of its financial statements the most useful and relevant basis for financial reporting given the significance of its rate regulated businesses. U.S. GAAP includes accounting standards for rate-regulated activities within the financial statements. Except where otherwise indicated, comparative amounts in this MD&A have been restated from the amounts previously reported under Canadian GAAP.

MANAGEMENT'S REPORT

Financial Reporting

The preparation and presentation of the accompanying Consolidated Financial Statements, MD&A and all financial information in the Financial Statements are the responsibility of management and have been approved by the Board of Directors. The Financial Statements have been prepared in accordance with U.S. generally accepted accounting principles. Financial statements, by nature include amounts based upon estimates and judgments. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Management has prepared the financial information presented elsewhere in this document and has ensured that it is consistent with that in the consolidated financial statements.

The Board of Directors and its committees are responsible for all aspects related to governance of the Company. The Audit Committee of the Board, composed of directors who are unrelated and independent, has a specific responsibility to oversee management's efforts to fulfill its responsibilities for financial reporting and internal controls related thereto. The Committee meets with management and independent auditors to review the consolidated financial statements and the internal controls as they relate to financial reporting. The Audit Committee reports its findings to the Board for its consideration in approving the consolidated financial statements for issuance to the shareholders.

Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011, based on the framework established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as at December 31, 2011.

March 21, 2012

Ian Robertson	David Bronicheski
Chief Executive Officer	Chief Financial Officer

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Algonquin Power & Utilities Corp.

We have audited the accompanying consolidated financial statements of Algonquin Power & Utilities Corp., which comprise the consolidated balance sheet as at December 31, 2011 and December 31, 2010, the consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with US generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Algonquin Power & Utilities Corp. as at December 31, 2011 and December 31, 2010, and its consolidated results of operations and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada

March 21, 2012

Algonquin Power & Utilities Corp.

Consolidated Balance Sheets

(thousands of Canadian dollars)

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 72,887	$ 4,749
Short term investments (note 1(e))	833	3,674
Accounts receivable net of allowance for doubtful accounts of $255 and $380 (note 22)	44,394	25,875
Due from related parties (note 15)	2,275	718
Prepaid expenses	5,620	3,546
Supplies and consumables inventory	2,714	-
Current portion of notes receivable	482	1,172
Current portion of deferred tax asset (note 14)	13,022	14,015
Current portion of tax receivable (note 14)	133	-
Current regulatory assets (note 8)	2,458	-
	144,818	53,749
Long-term investments and notes receivable (note 5)	39,820	37,179
Deferred non-current income tax asset (note 14)	67,671	74,006
Property, plant and equipment (note 6)	945,956	761,740
Intangible assets (note 7)	55,269	73,886
Goodwill	9,710	995
Restricted cash (note 1(f))	4,693	3,564
Deferred financing costs	8,503	5,991
Non-current regulatory assets (note 8)	2,571	2,484
Other assets	3,577	3,355
	$ 1,282,588	$ 1,016,949
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 8,382	$ 2,182
Accrued liabilities	47,102	29,534
Current regulatory liabilities	2,469	-
Due to related parties (note 15)	1,795	1,534
Dividends payable	9,566	5,719
Current portion of long-term liabilities (note 9)	1,624	70,490
Current portion of other long-term liabilities (note 11)	1,037	420
Current portion of advances in aid of construction (note 1(o))	604	591
Current portion of derivative instruments (note 22)	2,935	2,338
Current income tax liability (note 14)	407	200
Current portion of deferred credit	6,314	11,020
Deferred income tax liability (note 14)	723	514
	82,958	124,542
Long-term liabilities (note 9)	331,092	189,468
Convertible debentures (note 10)	122,297	181,760
Other long-term liabilities (note 11)	11,027	11,405
Advances in aid of construction (note 1(o))	74,547	54,524
Non-current regulatory liabilities (note 8)	19,184	-
Deferred non-current income tax liability (note 14)	53,231	79,442
Derivative instruments (note 22)	5,209	3,525
Deferred credits (note 14)	30,348	32,222
Equity (note 12):		
Shareholders' capital	975,263	795,329
Additional paid-in capital	1,525	1,612
Deficit	(366,080)	(357,035)
Accumulated other comprehensive loss	(96,510)	(99,845)
Total Equity attributable to shareholders of Algonquin Power and Utilities Corp.	514,198	340,061
Non-controlling interest (note 3(a))	38,497	-
Total Equity	552,695	340,061
Commitments and contingencies (note 18)		
Subsequent events (notes 3, 6, 7, 8, 9, 10 and 12)		
	$ 1,282,588	$ 1,016,949

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Operations

(thousands of Canadian dollars, except per share amounts)

	2011	2010
Revenue:		
Non-regulated energy sales	$ 134,232	$ 129,977
Regulated energy sales and distribution	77,368	-
Waste disposal fees	16,406	9,039
Regulated water reclamation and distribution	44,989	38,011
Other revenue (note 17)	3,643	3,331
	276,638	180,358
Expenses		
Operating	88,420	69,568
Regulated commodities purchased	46,508	-
Non-regulated fuel for generation	24,628	25,929
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Administrative expenses	17,534	14,886
Write down of long-lived assets (notes 6 and 7)	16,520	2,492
Gain on foreign exchange	(652)	(528)
	238,784	158,962
Operating income	37,854	21,396
Interest expense	30,441	24,839
Interest, dividend income and other income (notes 16)	(5,659)	(5,164)
Acquisition related costs	2,965	3,015
Loss on derivative financial instruments (note 22 (c))	5,844	1,103
	33,591	23,793
Earnings (loss) from operations before income taxes	4,263	(2,397)
Income tax expense (recovery) (note 14)		
Current	300	(69)
Deferred	(23,339)	(20,722)
	(23,039)	(20,791)
Net earnings	27,302	18,394
Net earnings attributable to non-controlling interests	3,921	444
Net earnings attributable to shareholders of Algonquin Power & Utilities Corp.	$ 23,381	$ 17,950
Basic net earnings per share (note 19)	$ 0.20	$ 0.19
Diluted net earnings per share (note 19)	$ 0.20	$ 0.19

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Comprehensive Income (Loss)

(thousands of Canadian dollars)

		2011		2010
Net Earnings	$	27,302	$	18,394
Other comprehensive income (loss), before tax:				
Foreign currency translation adjustment due to accounting change (note 1(t))		-		(37,605)
Increase in unfunded pension obligation (note 1(q))		(48)		-
Foreign currency translation adjustment		4,272		(13,528)
Other comprehensive income, before tax:		4,224		(51,133)
Income tax expense related to items of other comprehensive income		-		-
Other comprehensive income (loss), net of tax:		4,224		(51,133)
Comprehensive income (Loss)		31,526		(32,739)
Less: comprehensive income attributable to the non-controlling interest		4,810		(444)
Comprehensive income (loss) attributable to shareholders of Algonquin Power & Utilities Corp	$	26,716	$	(33,183)

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statements of Cash Flows

(thousands of Canadian dollars)

	2011	2010
Cash provided by (used in):		
Operating Activities:		
Net earnings	$ 27,302	$ 18,394
Adjustments and items not affecting cash:		
Depreciation of property, plant and equipment	39,393	36,471
Amortization of intangible assets	6,433	10,144
Other amortization	2,192	2,148
Gain on sale of assets	(357)	-
Deferred taxes	(23,339)	(20,722)
Unrealized loss (gain) on derivative financial instruments	2,324	(7,142)
Share-based compensation	769	108
Write down of long-lived assets	16,520	2,492
Unrealized foreign exchange gain	-	(414)
Changes in non-cash operating items (note 20)	(1,542)	(85)
	69,695	41,394
Financing Activities:		
Cash dividends (note 13)	(28,582)	(18,901)
Cash distributions to non-controlling interest	(523)	(444)
Issuance of common shares	118,846	-
Deferred financing costs	(3,642)	(1,194)
Increase in long-term liabilities	204,759	98,787
Decrease in long-term liabilities	(134,932)	(80,078)
Increase in advances in aid of construction	6,288	4,857
Decrease in other long-term liabilities	(297)	(342)
	161,917	2,685
Investing Activities:		
Decrease / (increase) in restricted cash	(1,036)	575
Decrease / (increase) in short-term investments	(833)	36,212
Increase in other assets	(2,438)	(90)
Distributions received in excess of equity income	3,839	882
Receipt of principal on notes receivable	1,172	410
Increase in non-controlling interest	1,351	-
Proceeds from liquidation of Highground assets	1,073	170
Increase in long-term investments and notes receivable	(6,900)	(14,759)
Proceeds from sale of property, plant and equipment	1,583	-
Additions to property, plant and equipment	(60,745)	(20,789)
Acquisitions of operating entities (note 3(a))	(100,058)	(44,397)
	(162,992)	(41,786)
Effect of exchange rate differences on cash	(482)	(126)
Increase in cash and cash equivalents	68,138	2,167
Cash and cash equivalents, beginning of the period	4,749	2,582
Cash and cash equivalents, end of the period	$ 72,887	$ 4,749
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 28,143	$ 21,562
Cash paid during the period for income taxes	$ 195	$ (285)
Non-cash transactions		
Property, plant and equipment acquisitions in accruals	$ 8,556	$ -

See accompanying notes to consolidated financial statements

Algonquin Power & Utilities Corp.

Consolidated Statement of Equity

(thousands of Canadian dollars)

For the year ended December 31, 2011:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI	Non-controlling interests	Total
Balance, December 31, 2010	$ 795,329	$ 1,612	$ (357,035)	$ (99,845)	$ -	$ 340,061
Dividends declared and distributions to non-controlling interests	-	-	(32,426)	-	(523)	(32,949)
Conversion and redemption of convertible debentures	59,973	(815)	-	-	-	59,158
Issuance of common shares	118,888	-	-	-	-	118,888
Stock compensation expense	-	728	-	-	-	728
Acquisition of Liberty Energy (California)	-	-	-	-	34,210	34,210
Amounts received in connection with Highground transaction (note 3 (h))	1,073	-	-	-	-	1,073
Net earnings			23,381		3,921	27,302
Other comprehensive income	-	-	-	3,335	889	4,224
Balance, December 31, 2011	$ 975,263	$ 1,525	$ (366,080)	$ (96,510)	$ 38,497	$ 552,695

For the year ended December 31, 2010:

	Common Shares	Additional paid-in capital	Accumulated Deficit	Accumulated OCI (CTA)	Non-controlling interests	Total
Balance, December 31, 2009	$ 785,828	$ 1,487	$ (352,220)	$ (48,712)	$ -	$ 386,383
Dividends declared and distributions to non-controlling interests	-	-	(22,765)	-	(444)	(23,209)
Conversion and redemption of convertible debentures	4,568	17	-	-	-	4,585
Stock compensation expense	-	108	-	-	-	108
Amounts received in connection with Highground transaction (note 3 (h))	170	-	-	-	-	170
Issuance pursuant to management internalization	4,763	-	-	-	-	4,763
Net earnings			17,950		444	18,394
Other comprehensive loss	-	-		(51,133)	-	(51,133)
Balance, December 31, 2010	$ 795,329	$ 1,612	$ (357,035)	$ (99,845)	$ -	$ 340,061

Notes to the Consolidated Financial Statements

December 31, 2011 and 2010

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

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

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

The regulated utility operating companies owned by Liberty Utilities are subject to rate regulation generally overseen by the public utility commissions of the states in which they operate (see note 8).

1. Significant accounting policies

(a) Basis of preparation:

The accompanying consolidated financial statements and accompanying notes have been prepared in accordance with U.S. generally accepted accounting principles in the United States ("U.S. GAAP") and follow disclosures required under Regulation S-X provided by the Securities and Exchange Commission ("SEC"). These are the Company's first U.S. GAAP annual consolidated financial statements.

The Company's consolidated financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles ("Canadian GAAP") until December 31, 2010. Canadian GAAP differs in some areas from U.S. GAAP as was disclosed in the reconciliation to U.S. GAAP included in the audited annual financial statements for the year ended December 31, 2010. The accounting policies set out below have been consistently applied under U.S. GAAP to all the periods presented. The comparative figures in respect of 2010 were restated to reflect the adoption of U.S. GAAP.

(b) Basis of consolidation:

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

(c) Accounting for rate regulated operations:

APUC's regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process. Management believes the regulatory assets recorded in these financial statements are probable of recovery either because the Utilities received prior Regulator approval or due to regulatory precedent set for similar circumstances. Included in Note 8, Regulatory Assets & Liabilities are details of regulatory assets and liabilities, and their current regulatory treatment.

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

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

(d) Cash and cash equivalents:

Cash and cash equivalents include all highly liquid instruments with an original maturity of three months or less.

(e) Short term investments:

Short term investments, consist of money market instruments with maturities commencing from January 2012 and are recorded at current market value. Included in short term investments is an investment of $nil (U.S. $nil) which is denominated in U.S. dollars (December 31, 2010 - $3,674 (U.S. $3,694)).

1. Significant accounting policies (continued)

(f) Restricted cash:

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

(g) Accounts receivable

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

(h) Supplies and consumables inventory

Supplies and consumables inventory (other than capital spares and rotatable spares, which are included in property, plant, and equipment) are charged to inventory when purchased and then capitalized to plant or expensed, as appropriate, when installed, used or become obsolete. These items are stated at the lower of cost and replacement cost.

(i) Property, plant and equipment:

Property, plant and equipment, consisting of renewable and thermal generation assets, electrical, water and wastewater distribution assets, equipment and land, are recorded at cost. The costs of acquiring or constructing property, plant and equipment include the following: materials, labour, contractor and professional services, construction overhead directly attributable to the capital project (where applicable), interest for non-regulated property and allowance for equity funds used during construction ("AFUDC") for regulated property. Plant and equipment under capital leases are stated at the present value of minimum lease payments.

AFUDC reflects the cost of debt or equity funds used to finance construction and only is capitalized as part of the cost of regulated utility plant where such treatment is permitted by the regulator. AFUDC amounts capitalized are included in rate base for establishing utility rates. For operations that do not apply regulatory accounting, interest related only to debt is capitalized as a cost of construction in accordance with ASC 835. The interest capitalized that relates to debt reduces interest expense on the income statement. The AFUDC capitalized that relates to equity funds is recorded as interest, dividend and other income on the Statement of Operations.

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

1. Significant accounting policies (continued)

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

The Company's depreciation is based on the estimated useful lives of the depreciable assets in each category and is determined using the straight-line method. The range of estimated useful lives and the weighted average useful lives are summarized below:

	Range of useful lives		Weighted average useful lives	
	2011	2010	2011	2010
Generation				
Renewable	3 – 60	3 – 60	31	31
Thermal	3 – 40	3 – 40	22	22
Distribution				
Electrical	15 - 75	N/A	52	N/A
Water & wastewater	5 – 50	5 – 50	25	25
Equipment	5 – 50	5 – 50	24	24

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. It also includes amounts initially recorded as advances in aid of construction but where the advance repayment period has expired. These contributions are recorded as a reduction in the cost of utility assets and are amortized at the rate of the related asset.

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

(j) Intangibles:

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

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

1. Significant accounting policies (continued)

(k) Goodwill:

Goodwill represents the excess of the purchase price of an acquired business over the fair value of the net assets acquired. Goodwill is not included in rate-base and is not amortized.

In accordance with ASC Update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment" issued by the FASB in September 2011, the Company annually assesses qualitative factors to determine whether it is more likely than not that the fair value of goodwill is less than its carrying amount. If it is more likely than not that its fair value is less than its carrying amount, the Company calculates the fair value of the reporting unit. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit as a whole exceeds the reporting unit's fair value. An impairment charge is recorded for any excess of the carrying value of the goodwill over the implied fair value. Goodwill is tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.

(l) Impairment of long-lived assets:

APUC reviews property, plant and equipment and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable.

Assets Held and Used: Recoverability of assets held and used is measured by comparing the carrying amount of an asset to undiscounted expected future cash flows. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value.

Assets Held for Sale: Recoverability of assets held for sale is measured by comparing the carrying amount of an asset to its fair value less the cost to sell. If the carrying amount exceeds the recoverable amount, the asset is written down to its fair value less estimated costs to sell.

(m) Variable interest entities:

The Company performs analysis to assess whether its operations and investments represent variable interest entities ("VIEs"). To identify potential VIEs, management reviews contracts under leases, long-term purchase power agreements, tolling contracts and jointly-owned facilities. VIEs of which the Company is deemed the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where APUC is not deemed the primary beneficiary, the VIE is not consolidated.

Long Sault is a hydroelectric generating facility in which APUC acquired its interest by way of subscribing to two notes from the original developers. The notes receivable effectively provide APUC the right to 100% of after tax cash flows of the facility up to 2013, 65% from 2014 to 2027 and 58% thereafter. The Company also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038. APUC has determined that the facility is a VIE, since the Company is the primary beneficiary and therefore the Long Sault entity is subject to consolidation by the Company. Total generating assets and long-term debt of Long Sault amount to $46,160 (2010 -$47,757) and to $38,136 (2010 -$39,033), respectively. The financial performance of Long Sault reflected on the statement of operations includes non-regulated energy sales of $9,804 (2010 -$7,037), operating expenses and amortization of $3,001 (2010 -$2,572) and interest expense of $3,984 (2010 - $4,126).

1. Significant accounting policies (continued)

(n) Long-term investments and notes receivable:

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

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

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

(o) Advances in aid of construction:

The Company has various agreements with real estate development companies conducting business within the Company's service territories (the "developers"), whereby funds are advanced to the Company by the developers to assist with funding some or all of the costs of the development. These amounts are recorded as Advances in Aid of Construction in other long-term liabilities. In many instances, developer advances are subject to refund but the refund is non-interest bearing. Refunds of developer advances are made over periods ranging from 10 to 20 years. Generally, advances not refunded within the prescribed period are not required to be repaid. After the prescribed period has lapsed, any remaining unpaid balance is transferred to contributions in aid of construction and recorded as an offsetting amount to cost of property, plant and equipment. In 2011, $1,107 (2010 - $nil) was transferred from advances in aid of construction to contributions in aid of construction.

(p) Other long-term liabilities:

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

1. Significant accounting policies (continued)

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

Other long term liabilities also include customer deposits. Customer deposits result from the Liberty Utilities' obligation by state regulators to collect a deposit from customers of its facilities under certain circumstances when services are connected. The deposits are refundable as allowed under the facilities' regulatory agreement. The deposits bear monthly interest and are applied to the customer account after 12 months if the customer is found to be credit worthy.

(q) Pension plan:

Liberty Utilities (West) has a defined benefit cash balance pension plan covering substantially all its employees, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The plan interest credit rate varies from year-to-year based on the five-year U.S. Treasury bonds yield plus 0.25%. Employees' benefits under the plan are fully vested upon completion of three years of service. The Company's policy is to make contributions within the range determined by generally accepted actuarial principles. The costs of the Company's pension for employees are expensed over the periods during which employees render service. The Company recognizes the funded status of its defined-benefit plan on the consolidated balance sheet and recognizes changes in funded status in the year the change occurs. The Company recognizes the unamortized gains and losses and past service costs in Accumulated other comprehensive income ("AOCI"). The projected benefit obligation of $230 exceeds the fair value of the plan assets of $200 as at December 31, 2011. Benefit cost of $182 and actuarial loss of $48 are reflected in earnings and other comprehensive income, respectively. The assumptions used in calculating the pension obligation include a discount rate of 4%, expected return on plan assets of 6% and rate of compensation increase of 4%. As at December 31, 2011, plan assets are invested in fixed income securities.

(r) Asset retirement obligations:

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

(s) Recognition of revenue:

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

Water reclamation and distribution revenues are recorded when water is processed or delivered to customers. At the end of each month, the water delivered and waste water collected from the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled revenues are based on the ratio of billable days versus unbilled days, amount of water procured and collected during that month, historical customer class usage patterns and current tariffs.

1. Significant accounting policies (continued)

(s) Recognition of revenue (continued):

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

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts is recognized based on actual tonnage at the expected price for the contract year.

Interest from long-term investments is recorded as earned.

(t) Foreign currency translation:

The Company's reporting currency is the Canadian dollar.

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

As a result of the change relating to conversion of the Company from an income trust to a corporate structure at the end of 2009, the Company re-evaluated its exposure to currency exchange rate changes as determined by the underlying facts and circumstances of the economy in which the US divisions operate. The Company concluded that the functional currency of the US operations of the Renewable Energy and Thermal Energy divisions has become the U.S. dollar. Consequently, these divisions have been prospectively translated into Canadian dollars using the current rate method, effective January 1, 2010. The net exchange adjustment of $37,605 resulting from the current rate translation of non-monetary items, principally property, plant and equipment and intangible assets, as of the date of the change is included as a separate component of other comprehensive income with a corresponding reduction to the carrying amount of the non-monetary items.

(u) Stock Based Compensation

The Company has several share-based compensation plans: a share option plan; an employee common share purchase plan ("ESPP"); a deferred share unit ("DSU") plan; and a performance share unit ("PSU") plan. The Company recognizes all employee stock-based compensation as a cost in the financial statements. Equity classified awards are measured at the grant date fair value of the award. The Company estimates grant date fair value using the Black-Scholes option pricing model. Liability classified awards are measured at fair value based on the average common share price over the five days immediately preceding the date of issue and at the end of the reporting period using the average over the days ending on the financial statement date.

1. Significant accounting policies (continued)

(v) Income taxes:

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

The organizational structure of APUC and its subsidiaries is complex and the related tax interpretations, regulations and legislation in the tax jurisdictions in which they operate are continually changing. As a result, there can be tax matters that have uncertain tax positions. The Company follows FASB ASC 740-10 and recognizes the effect of income tax positions only if those positions are more likely than not of being sustained. Recognized income tax positions are measured at the largest amount that is greater than 50% likely of being realized. Changes in recognition or measurement are reflected in the period in which the change in judgment occurs.

(w) Financial instruments and derivatives:

APUC has classified its cash and cash equivalents, short term investments, and restricted cash as held-for-trading, which are measured at fair value. Accounts receivable and notes receivable are measured at amortized cost and there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are measured at amortized cost using the effective interest method, adjusted for the amortization or accretion of premiums or discounts.

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

The Company uses derivative financial instruments as one method to manage exposures to fluctuations in exchange rates, interest rates and commodity prices. APUC recognizes all derivative instruments as either assets or liabilities in the Consolidated Balance Sheet at their respective fair values and the change in fair value is included in the Consolidated Statements of Operations. None of the derivatives were designated in hedging relationships for accounting purposes. The Company's derivative program is not designed or operated for trading or speculative purposes.

Liberty Utilities (West) enters into Power Purchase Agreements ("PPA") for load serving requirements. These contracts meet the exemption for normal purchase and normal sales and as such, are not required to be marked-to-market and are accounted for on an accrual basis. We evaluate our counterparties on an on-going basis for non-performance risk to ensure it does not impact our conclusion with respect to this exemption.

1. Significant accounting policies (continued)

(x) Fair Value Measurements

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

- Level 1 Inputs: Unadjusted quoted prices in active markets for identical assets or liabilities accessible to the reporting entity at the measurement date.
- Level 2 Inputs: Other than quoted prices included in Level 1 inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the asset or liability.
- Level 3 Inputs: Unobservable inputs for the asset or liability used to measure fair value to the extent that observable inputs are not available, thereby allowing for situations in which there is little, if any, market activity for the asset or liability at measurement date.

(y) Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, fines, and penalties and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Legal costs incurred in connection with loss contingencies are expensed as incurred.

(z) Use of estimates

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

2. Recently issued accounting pronouncements

(a) Recently Adopted Accounting Pronouncements

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

2. Recently issued accounting pronouncements (continued)

(a) Recently Adopted Accounting Pronouncements (continued)

In December 2010, the FASB issued ASC update No. 2010-29, "Business Combinations (Topic 805), Disclosure of Supplementary Pro Forma Information for Business Combinations, a consensus of the FASB Emerging Issues Task Force." This amendment clarifies the periods for which pro forma financial information is presented. The acquisition of the California Utility occurred on January 1, 2011 and therefore the Statement of Operations for the year ended December 31, 2011 contains a full year of operating results from this acquisition. Accordingly pro forma financial statements would not provide any additional information. As the business combination was an acquisition of a division of the vendor for which comparable results from operations for the previous year are not available, pro forma financial statements for the comparative period are not provided as they cannot be practicably obtained. The adoption of this update did not have a material impact on the Company`s financial statements.

In September 2011, the FASB issued ASC update No. 2011-08 "Intangibles-Goodwill and Other (Topic 350), Testing Goodwill for Impairment". This Update revises how an entity tests goodwill for impairment. The new guidance allows an entity to first assess qualitative factors to determine whether it is necessary to perform the two-step quantitative goodwill impairment test. An entity is no longer required to calculate the fair value of a reporting unit unless the entity determines, based on a qualitative assessment, that it is more likely than not that its fair value is less than its carrying amount. As permitted by the Update, the Company has early adopted this standard in these annual financial statements for the year ended December 31, 2011. The adoption of this update did not have a material impact on the Company`s financial statements.

In June 2011, the FASB issued ASC update No. 2011-05 "Presentation of Comprehensive income (Topic 220)". This Update provides accounting guidance on presentation of comprehensive income. The new guidance eliminates the current option to report Other comprehensive income ("OCI") and its components in the statement of changes in stockholders' equity. The new guidance requires the changes in OCI be presented either in a single continuous statement of net income and OCI or in two separate but consecutive statements. As permitted by the Update, the Company has early adopted the presentation guidance in these annual financial statements for the year ended December 31, 2011. The amendments resulted in presentation changes only in the consolidated financial statements.

Subsequently in December 2011, the FASB issued ASC update No. 2011-12, "Deferral of the Effective Date for Amendments to Presentation of Reclassification of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05". The amendments in ASU No. 2011-12 defer the changes in ASU No. 2011-05 that relate to the presentation of reclassification adjustments out of AOCI.

(b) Recent Accounting Guidance Not Yet Adopted

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

2. Recently issued accounting pronouncements (continued)

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

In May 2011, the FASB issued ASC update No. 2011-04 “Fair Value Measurement (Topic 820)”. This Update amends the accounting and disclosure requirements for fair value measurements. The new guidance expands the disclosures about fair value measurements categorized within Level 3 of the fair value hierarchy and requires categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The new guidance will be effective for the Company’s quarter ending March 31, 2012, and will be applied prospectively. Other than requiring additional disclosures, the adoption of this guidance is not expected to have a material impact on the Company’s consolidated financial statements.

3. Acquisitions

(a) Acquisition of California electrical generation and regulated distribution utility

On January 1, 2011, APUC and Emera Inc. (“Emera”) closed the acquisition of the “California Utility” for a purchase price of approximately $135,343 (U.S. $136,077). Through its wholly owned subsidiary Liberty Energy (California), APUC owns 50.001% of the shares of California Pacific Utility Ventures LLC, which acquired the California Utility and has concluded it controls the acquired entity. Liberty Energy (California) provides electric distribution service to approximately 47,000 customers in the Lake Tahoe region. The other 49.999% of the shares were acquired by Emera in the same transaction. The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition.

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

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

Working capital	$ 8,964
Property, plant and equipment	146,064
Deferred income tax asset	2,056
Goodwill	8,268
Current portion of other long-term liabilities	(671)
Advances in aid of construction	(10,434)
Other long-term liabilities	(1,988)
Regulatory liabilities	(16,916)
Total net assets acquired	$ 135,343

The acquisition was funded as follows:

Contribution of equity by APUC in 2011	$ 29,074
Contribution of equity by APUC in 2010	3,787
Non-controlling interest portion of purchase price paid by Emera	32,860
Debt financing	69,622
Total acquisition consideration	$ 135,343

3. Acquisitions (continued)

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

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

The determination of the fair value of assets and liabilities acquired has been based upon fair value measurements.

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

Property, plant & equipment of Liberty Energy (California) are amortized on a straight line basis, ranging from 15 to 75 years in accordance with regulatory requirements.

The Company incurred $2,572 in total acquisition-related costs (2010 - $2,210); of which $362 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

As the acquisition closed on January 1, 2011, the financial statements for the year ended December 31, 2011 contain a full year of operating results for the utility. Liberty Energy (California) contributed revenue of $77,367 and earnings of $2,987 to the Company's results for the year ended December 31, 2011. The disclosure of pro forma revenue and earnings related to 2010 is impracticable since the assets acquired were part of a small division of a much larger utility; separate financial statements were not maintained by the vendor of the assets, the regulated tariff driving revenue formulae has changed, the rate-base used in determining rates was not identical to the assets acquired and the operating costs were subject to extensive allocation.

(b) Acquisition of Regulated Water Utilities

On September 20, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of Noel Water Co., Inc. ("Noel"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $903 was paid in cash. The following assets were acquired at fair values: working capital of $28 and property, plant and equipment of $729. Goodwill amounting to $146 was recognized.

On November 9, 2011, Liberty Utilities (South) completed the acquisition of the water utility assets of KMB Utility Corporation ("KMB"). The acquisition has been accounted for using the acquisition method, with earnings from operations consolidated since the date of acquisition. Total acquisition consideration of $350 was paid in cash. The following assets were acquired at fair values: working capital of $43 and property, plant and equipment of $265. Goodwill amounting to $42 was recognized.

Both utilities are located in the state of Missouri.

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

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

3. Acquisitions (continued)

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

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

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

The Company incurred $3,271 in total acquisition-related costs (2010 - $1,889); of which $1,382 were incurred during 2011. All such costs have been expensed in the consolidated Statement of Operations.

(d) Agreement to Acquire Mid-West Gas Utilities

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

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

The Company incurred $398 in total acquisition-related costs during 2011 (2010 - $nil). All such costs have been expensed in the consolidated Statement of Operations.

(e) Agreement to Acquire Solar Energy Project

On November 27, 2011, APCo entered into agreements to acquire rights, subject to Ontario Power Authority approval, to develop a 10 MW-AC solar project located near Cornwall, Ontario which has been granted an Ontario Feed-in-Tariff contract by the Ontario Power Authority for a 20 year term at a rate of $443/MWh. The consideration for the power sale contract is $4,500 plus additional contingent consideration of $3,500 that is based on achieving certain construction milestones.

On December 30, 2011 Ontario Power Authority Approval was received and the transaction closed on January 4, 2012. Following the completion of all regulatory submissions and approvals, construction of the solar facility is expected to begin in the second half of 2012, with a commercial operation date estimated in early 2013.

(f) Power Purchase agreement for Chaplin Wind Project

Subsequent to the year end, APCo entered into a 25 year Power Purchase Agreement with SaskPower for development of a 177 –MW wind power project in the rural municipality of Chaplin, Saskatchewan, 200 km west of Regina, Saskatchewan. The project has a targeted commercial operation date of December, 2016. The 25 year power purchase agreement features a rate escalation provision of 0.6% throughout the term of the agreement.

3. Acquisitions (continued)

(g) Highground Capital Corporation

In 2008, the Company entered into an agreement with Highground Capital Corporation ("Highground") and CJIG Management Inc. ("CJIG) whereby, CJIG acquired all of the issued and outstanding common shares of Highground and the Company issued equity in the form trust units to the Highground shareholders and CJIG, in exchange for $26.2 million of cash and future consideration based on 50% of liquidation proceeds from sale of Highground's remaining assets by CJIG. During 2011, APUC received additional consideration of $1,073 (2010 - $170) from CJIG as APUC's share of additional proceeds. This has been recorded as an increase to share capital. As at December 31, 2011, further consideration from this transaction, if any, is not expected to be significant.

(h) Acquisition of U.S. Wind Farms

On March 9, 2012, APCo entered into an agreement to acquire a 51% majority interest in a 480 MW portfolio of four wind projects in the United States from Gamesa Corporación Tecnológica, S.A. ("Gamesa") for total consideration of approximately U.S. $269 million. The portfolio will be acquired in two stages; closing of two existing wind farms is expected to occur promptly following receipt of regulatory approval and the acquisition of the remaining two wind farms following their respective commissionings near the end of 2012.

4. Accounts receivable

Accounts receivable as of December 31, 2011, include unbilled receivables of $11,304 (December 31, 2010 - $1,552) in the regulated utilities. The unbilled revenue is an estimate of the amount of utility revenue since the date the meters were last read.

5. Long-term investments and notes receivable

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

	2011	2010
32.4% of Class B non-voting shares of Kirkland Lake Power Corp.	$ 4,926	$ 8,197
25% of Class B non-voting shares of Cochrane Power Corporation	5,382	5,775
45% interest in the Algonquin Power (Rattle Brook) Partnership	3,784	3,790
50% interest in the Valley Power Partnership	1,676	1,845
Red Lily Subordinated loan, interest at 12.5% (b)	6,565	6,565
Red Lily Senior loan, interest at 6.31% (b)	13,000	6,100
Chapais Énergie, Société en Commandite 12.1% interest in Tranche A and Tranche B term loans The loans bear interest at the rate of 10.789% and 4.91%, respectively	2,913	3,329
Silverleaf resorts loan, interest at 15.48% (c)	2,056	2,010
Note Receivable - Twin Falls. The note bears interest at the rate of 6.75%	-	740
	40,302	38,351
Less: current portion	(482)	(1,172)
Total long term investments and notes receivable	$ 39,820	$ 37,179

The above notes are secured by the underlying assets of the respective facilities. There is no allowance for doubtful account in regards to the notes receivable as at December 31, 2011 and 2010.

5. Long-term investments and notes receivable (continued)

(a) Red Lily I

The Red Lily I Partnership (‘Partnership”) is owned by an independent investor. The Company provides operation and supervision services to the Red Lily I project, a 26.4 megawatt wind energy facility located in south-eastern Saskatchewan.

The Company’s investment in Red Lily I is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility from the Partnership. APUC has advanced $13,000 (2010 - $6,100) under a senior debt facility to the Partnership. Another third party lender has also advanced $31,000 of senior debt to the Partnership. The Company’s senior loan to the Partnership earns interest at the rate of 6.31% and will mature in 2016. Both tranches of senior debt are secured by substantially all the assets of the Partnership on a pari passu basis.

The subordinated loan earns an interest rate of 12.5%, the principal matures in 2036 but is repayable by the Partnership in whole or in part at any time after 2016, without a pre-payment premium. The subordinated loan is secured by substantially all the assets of the Partnership but is subordinated to the senior debt.

A second tranche of subordinated loan for an amount equal to the amounts outstanding on Tranche 2 of the senior debt but no greater than $17,000 will be advanced in 2016 by the Company. The proceeds from this additional subordinated debt are required to be used to repay Tranche 2 of the Partnership’s senior debt, including APUC’s portion.

In connection with the subordinated debt facility, the Company has been granted an option to subscribe for a 75% equity interest in the Partnership in exchange for the outstanding amount on its subordinated loan of up to $19,500, exercisable for a period of 90 days commencing in 2016. The fair value of the conversion option as at December 31, 2011 was determined to be negligible.

During the year ended December 31, 2011, APUC advanced $6,900 of the senior debt to the Partnership. As of December 31, 2011 APUC has funded a total of $13,000 (December 31, 2010 - $6,100) of the senior debt and $6,565 (December 31, 2010 - $6,565) of the subordinated debt.

(b) Silverleaf Resorts Inc – Hill County

On July 29, 2010, Liberty Water, a wholly owned subsidiary of APUC, made an investment in its Hill Country facility, a part of Silverleaf Resorts Inc.’s (“SRI”) facilities in Comal County, Texas. The investment of $2,056 (U.S. $2,021) was made under an agreement with SRI to increase the capacity of a wastewater treatment facility to support the growth of the utility. This investment has been recorded in property, plant and equipment as additional capacity conveyed by SRI together with note receivable for funds advanced by APUC.

The note has a 10 year term and bears interest at 15.48%. The note is repayable in cash to the extent expansion does not form part of the rate base of the utility during the 10 year term. To the extent that the cost of the expansion becomes part of the rate base of the utility, the note will be assigned as payment to Silverleaf for the expansion costs with the excess received in cash.

6. Property, plant and equipment

Property, plant and equipment consist of the following:

2011

	Cost	**Accumulated depreciation**	**Net book value**
Generation			
Renewable	$527,922	$132,779	$395,143
Thermal	194,080	78,776	115,304
Distribution			
Water & wastewater	239,190	48,716	190,474
Electricity	154,154	2,636	151,518
Land	12,203	-	12,203
Equipment	50,823	23,429	27,394
Construction in progress	53,920	-	53,920
	$ 1,232,292	$ 286,336	$ 945,956

2010

	Cost	**Accumulated depreciation**	**Net book value**
Generation			
Renewable	$ 527,407	$ 114,780	$ 412,627
Thermal	191,138	69,816	121,322
Distribution			
Water & wastewater	219,744	41,840	177,904
Electricity	-	-	-
Land	11,976	-	11,976
Equipment	48,720	21,309	27,411
Construction in progress	10,500	-	10,500
	$ 1,009,485	$ 247,745	$ 761,740

Generation assets are those used to generate electricity. These assets include hydroelectric, wind and thermal generation stations, turbines, dams, reservoirs and other related equipment.

Electricity distribution assets are those used to distribute electricity within a specific geographic service territory to end users of electricity. These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Water and waste water assets are those used to distribute water and collect wastewater. These assets include treating facilities and equipment, network of supply mains, pipes and canals, pumps and related generation equipment, meters, hydrants, collecting sewers and other related equipment.

Equipment assets include equipment, vehicles, inventory and information technology assets.

Renewable generation assets include cost of $94,606 (2010 - $94,606) and accumulated depreciation of $30,264 (2010 - $27,962) related to facilities under capital lease or owned by consolidated variable interest entities. Depreciation expense of facilities under capital lease was $2,302 (2010 - $2,536). Contributions received in aid of construction of $3,968 (2010 - $3,731) have been credited to the cost of the distribution assets. Water and wastewater distribution assets include expansion costs of $1,000 on which the Company does not currently earn a return.

Equipment includes cost of $4,227 (2010 - $4,402) and accumulated depreciation of $2,079 (2010 - $2,149) related to equipment under capital lease. Depreciation expense of equipment under capital lease was $282 (2010 - $292).

6. Property, plant and equipment (continued)

In December 2011, APCo wrote down its investment in a small hydro facility and recognized an impairment charge on property, plant and equipment of $1,370 (2010 - $1,836) representing the difference between the carrying value of the assets and their estimated fair value. The fair value of the facilities was estimated based on prior transactions involving sales of comparable facilities and management's best estimates. Subsequent to the year end the Company entered into an agreement to sell certain small hydro facilities located in the U.S for gross proceeds of $200. As a result, the Company wrote down its investment in these hydro facilities to fair value, less costs associated with the sale, and recognized a charge on property, plant and equipment of $662 (2010 - $656).

In December 2011, Liberty Utilities (South) wrote down $1,058 from facilities assets based on regulatory decisions in 2011 that these costs are not capitalizable for rate-base purposes.

7. Intangible assets

Intangible assets consist of the following:

2011

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 60,044	$ 20,548	$ 39,496
Customer relationships	19,235	3,462	15,773
Energy sales contract	-	-	-
	$ 79,279	$ 24,010	$ 55,269

2010

	Cost	Accumulated amortization	Net book value
Power sales contracts	$ 102,980	$ 45,345	$ 57,635
Customer relationships	18,811	2,912	15,899
Energy sales contract	4,228	3,876	352
	$ 126,019	$ 52,133	$ 73,886

Subsequent to the year end, the Region of Peel elected not to extend the existing waste processing contract with the Company and will instead seek competitive proposals from several waste management companies, including the Company. As a result, the remaining intangible assets associated with the existing waste management and energy contracts of the facility were written off in 2011 and the Company recognized a charge on intangible assets of $13,430.

Estimated amortization expense for intangibles for the next five years is $4,190 each year.

8. Regulatory assets and liabilities

The Company's regulated utility operating companies owned by Liberty Utilities are subject to regulation by the public utility commissions of the states in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities operate under cost-of-service regulation as administered by these state authorities. The Company`s regulated utility operating companies are accounted for under the principles of U.S. Financial Accounting Standards Board ASC Topic 980 Regulated Operations ("ASC 980"). Under ASC 980, regulatory assets and liabilities that would not be recorded under U.S. GAAP for non-regulated entities are recorded to the extent that they represent probable future revenues or expenses associated with certain charges or credits that will be recovered from or refunded to customers through the rate making process.

The utilities periodically file rate cases with their regulators. Rate cases seek to ensure that a particular facility has the opportunity to recover its operating costs and earn a fair and reasonable return on its capital investment as allowed by the regulatory authority under which the facility operates. Regulated utilities use a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Liberty Utilities monitors current and anticipated operating costs, capital investment and the rates of return in respect of each of its facility investments to determine the appropriate timing of a rate case filing in order to ensure it fully earns a rate of return on its investments. In the case of Liberty Utilities (West) and consistent with regulated utilities operating in California, the utility is required to make general rate case filings on a regular 3 year cycle. The utilities' most recent rate case was settled in 2009. The rate case was filed in February 2012 for the prospective years of 2012-2013. The regulator allows for the use of a prospective test year in the establishment of rates for the utility. The regulator also allows the use of annual adjuster mechanisms to account for inflation to labor and other expenses over the three year period of the rate case filing. In addition, a utility's rates include thresholds for capital expenditures, which once reached, can trigger adjustment mechanisms in between rate cases.

Energy Cost Adjustment Clause ("ECAC")

A portion of the revenue of Liberty Utilities (West) consists of ECAC which is designed to recoup or refund power supply costs that are caused by the fluctuations in the price of fuel and purchased power. The ECAC allowed in California mitigates the impact of changes in fuel prices and stabilizes earnings by allowing for the recovery of fuel and purchased power costs by updating rates charged on an annual basis. The mechanism consists of a base rate and amortization rate. The actual power supply costs incurred are tracked and compared to the base rate power supply costs to ensure the cumulative variance does not exceed 5%. In the event that the cumulative variance exceeds 5%, the ECAC allows Calpeco to request an adjustment to approved rates, reducing the commodity risk associated with the purchase of power.

The Post Test Year Adjustment Mechanism ("PTAM")

The PTAM allows Calpeco to update its rates annually by a cost inflation index. In addition, rates are allowed to be updated to recover the return on investment and associated depreciation of major capital projects.

8. Regulatory assets and liabilities (continued)

Power Purchase Agreement ("PPA")

Liberty Utilities (West) has entered into a five year all requirements PPA with NV Energy to provide its full electric needs at NV Energy's "system average cost" rates. The PPA had an effective starting date of January 1, 2011 with a five year renewal option. The PPA obligates NV Energy to use commercially reasonable efforts to supply Liberty Utilities (West) with sufficient renewable power to satisfy the current 20% California Renewables Portfolio Standard requirement for the five-year term of the PPA. NV Energy's deliveries under the PPA are structured in a manner which satisfies the CPUC resource adequacy ("RA") requirements, and are designed to enable Liberty Utilities (West) to comply with the associated RA reporting requirements. Liberty Utilities (West) accounts for the PPA as an operating lease. The costs associated with the PPA are recoverable through the ECAC.

Regulatory assets and liabilities consist of the following:

	December 31, 2011	December 31, 2010
Regulatory assets:		
Rate case costs (i)	$ 2,161	$ 2,164
Alternative revenue program (ii)	2,789	320
Water testing costs (iii)	79	-
Total regulatory assets	$5,029	$ 2,484
Less current regulatory assets	2,458	-
Non-current regulatory assets	$2,571	$ 2,484
Regulatory liabilities		
Deferred energy costs (iv)	$ 6,708	$ -
Cost of removal (v)	14,945	-
Total regulatory liabilities	$ 21,653	$ -
Less current regulatory liabilities	2,469	-
Non-current regulatory liabilities	$ 19,184	$ -

(i) Rate case

The costs to file, prosecute and defend rate case applications are referred to as rate case costs and are generally recoverable, in whole or in part, as part of the rate case process over a prescribed period of time. Deferred rate case costs are those rate case costs the utility expects to receive prospective recovery through its rates approved by the regulators. Under ASC 980 these costs are capitalized and amortized over the period of rate recovery granted by the regulator. The Company does not earn a return on these amounts but gets recovery of these costs in rates over the periods prescribed by the regulator.

8. Regulatory assets and liabilities (continued)

(ii) Alternative revenue program

A rate decision by the regulator of one of Liberty Utilities (South)'s utilities has ordered a phase-in of the rate increases it has granted wherein the full rate increase will be phased in over a 12 month period. The phase-in also includes a surcharge mechanism that ensures the utility is not disadvantaged by the phase in of the new rates.

(iii) Water testing costs

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

(iv) Deferred energy cost

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

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the consolidated statement of operations but rather is deferred and recorded as a regulatory asset on the balance sheet in accordance with the provisions of ASC 980. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to regulatory review. The Utilities also record and are eligible under the statute to recover a carrying charge on such deferred balances.

(v) Cost of removal

The regulatory liability for cost of removal represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant.

Future implications of discontinuing application of regulatory accounting

Liberty Utilities regularly assesses whether it can continue to apply regulatory accounting to its operations. In the event that the criteria no longer applied to a deregulated portion of the operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory mechanism is provided. Additionally, these factors could results in an impairment on utility assets.

8. Regulatory assets and liabilities (continued)

Income statement impact of applying regulatory accounting

If Liberty Utilities had not applied regulatory accounting earnings would have been affected as follows:

	December 31, 2011	December 31, 2010
Liberty Utilities (South):		
As a result of not recognizing the alternative revenue program in advance of the full rate increase being phased in rates, the rate case costs would have been expensed as incurred and revenue recognized would have been limited to the current phase of the phase-in plan.	$(1,825)	$(332)
Liberty Utilities (West):		
Recognizing over-recovered purchased power costs net of capitalized rate-case that would have been expensed.	4,106	-
Total increase (decrease) in earnings	$ 2,281	$(332)

9. Long-term liabilities

Long term liabilities consist of the following:

	2011	2010
APCo		
Senior Unsecured Notes: $135,000 senior unsecured notes, interest rate of 5.5% maturing July 25, 2018. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012.	$ 134,778	$ -
Senior Secured Revolving Credit Facility: Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 2.5%.	-	64,500
Senior Debt Long Sault Rapids: Interest at rate of 10.2% repayable in blended monthly interest and principal installments of $402 and maturing December, 2027.	39,033	39,844
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2011 is 2.05% (2010 – 1.33%).	19,526	19,096
Senior Debt Chute Ford: Interest rate of 11.6% repayable in blended monthly interest and principal installments of $64 and maturing April, 2020.	4,072	4,350
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matured on October 31, 2011. Monthly interest and quarterly principal payments totaled $72,146 (2010 - $1,741). The effective rate of interest for 2011 was 1.38% (2010 – 1.81%).	-	68,789
Bonds Payable: Obligation to the City of Sanger (2010 - U.S. $230).	-	229
Liberty Utilities		
Senior Notes – California Pacific Electric Company, LLLC: U.S. $45,000 senior unsecured notes, interest rate of 5.19%, maturing December 29, 2020 and U.S. $25,000, interest rate of 5.59%, maturing December 29, 2025. The notes are interest only, payable semi-annually.	71,190	-

9. Long term liabilities (continued)

	2011	2010
Senior Unsecured Notes – Liberty Water Co: U.S. $50,000 senior unsecured notes, interest rate of 5.6% maturing December 22, 2020. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and an annual principal repayment of U.S. $5,000 thereafter.	50,850	49,730
Litchfield Park Service Company Bonds: 1999 and 2001 IDA Bonds. Interest rates of 5.95% and 6.75% repayable in blended semi-annual installments maturing October 2023 and October 2031. Principal payments of U.S. $270 (2010 – U.S. $255). The balance of these notes at December 31, 2011 was U.S. $3,605 and U.S. $7,100, respectively (2010 – U.S. $3,810 and U.S. $7,165).	11,868	11,931
Bella Vista Water Loans: Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March, 2020 and December, 2017. The balance of these notes at December 31, 2011 was US$1,275 and US$83 respectively (2010 – US$1,384 and US$95)	1,399	1,489
	$ 332,716	$ 259,958
Less: current portion	(1,624)	(70,490)
	$ 331,092	$ 189,468

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

APCo

On July 25, 2011 APCo completed a $135,000 private placement debt financing commitment at a price of $998.28 per $1,000 principal amount of debenture. The notes are senior unsecured with a seven year maturity date of July 25, 2018 and bear interest at 5.5%. The notes are interest only, payable semi-annually in arrears, commencing January 25, 2012. APCo incurred deferred financing costs of $1,685, which are being amortized to interest expense over the term of the loan using the effective interest rate method. The net proceeds of this financing were used to retire the project debt related to the St. Leon facility (Air Source Senior Debt Financing) and to reduce amounts outstanding on APCo's senior secured revolving credit facility. As of December 31, 2011, the Company had accrued $3,255 in interest payable.

9. Long term liabilities (continued)

In February 2011, APCo renewed its senior secured revolving credit facility in the maximum amount of $142,000 (the “Facility”) for a three year term with its Canadian bank syndicate. The Facility now has a maturity date of February 14, 2014. Refinancing costs and fees related to the renewal of $1,446 have been recorded as deferred financing costs in the period. On July 25, 2011, in conjunction with the APCo debenture offering discussed above, the maximum availability on the senior revolving facility was reduced to $120,000. At December 31, 2011, $0 (2010 - $64,500) has been drawn on the Facility. In addition, the availability of the revolving credit facility has been reduced for certain outstanding letters of credit in amounts totaling $39,606 (2010 - $33,122).

Therefore, APCo had $80,394 of undrawn bank facilities as at December 31, 2011. The terms of the Facility contain certain financial covenants including debt service ratios and leverage ratios which can limit the amounts available for borrowing. Based on current covenants at December 31, 2011, APCo is able to access the entire undrawn amount of the Facility. The facility is secured by a fixed and floating charge over all APCo entities.

On December 22, 2010 APUC’s subsidiary, Liberty Water Co. (“Liberty Water”), issued U.S. $50,000 senior unsecured notes with a ten year maturity date of December 2020 and bearing interest at 5.6%. The notes are interest only, payable semi-annually, until June 20, 2016 with semi-annual interest payments and annual principal repayments of U.S. $5,000 thereafter. As of December 31, 2011, Liberty Water incurred deferred financing costs of $1,235 (2010 - $854) which are being amortized to interest expense over the term of the loan using the effective interest rate method.

APUC’s subsidiary California Pacific Electric Company, LLC has issued U.S.$70,000 senior unsecured notes consisting of U.S. $45,000 bearing an interest rate of 5.19% maturing December 29, 2020 and U.S. $25,000 bearing an interest rate of 5.59% maturing December 29, 2025. The notes are interest only, payable semi-annually. Financing costs of $ 1,048 (2010 - $1,069) incurred with respect to this placement have been recorded in deferred financing costs.

Subsequent to year-end, on January 19, 2012, Liberty Utilities Co. entered into an agreement for a U.S. $80,000 senior unsecured revolving credit facility with a three year term at an interest rate equal to LIBOR plus a variable rate as outlined in the credit facility agreement. The current rate is LIBOR plus 1.75%.

Interest paid on the long-term liabilities was $18,089 (2010 - $9,064).

9. Long term liabilities (continued)

Principal payments due in the next five years and thereafter are:

	2012	2013	2014	2015	2016	Thereafter	Total
APCo							
Senior Unsecured	$ -	$ -	$ -	$ -	$ -	$134,778	$134,778
Senior Debt Long Sault Rapids	897	993	1,094	1,211	1,340	33,498	39,033
Sanger Bonds	-	-	-	-	-	19,526	19,526
Senior Debt Chuteford	309	346	389	436	489	2,103	4,072
Liberty Utilities							
Senior Unsecured	-	-	-	-	5,085	45,765	50,850
Senior Unsecured	-	-	-	-	-	71,190	71,190
Litchfield Park Service Company Bonds	290	305	326	346	366	10,235	11,868
Bella Vista Water Loans	128	136	135	144	140	716	1,399
Total	$1,624	$1,780	$1,944	$2,137	$7,420	$317,811	$332,716

10. Convertible Debentures

2011	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$4.08	$6.00	$4.20	
Carrying value at December 31, 2010	$ 59,156	$ 59,699	$ 62,905	$ 181,760
Conversion to shares (Note12), net of costs	(59,449)	(10)	(334)	(59,793)
Amortization and accretion	293	37	-	330
Carrying value at December 31, 2011	$ -	$59,726	$62,571	$122,297
Face value at December 31, 2011	$ -	$59,957	$62,571	$122,528

2010	Series 1A	Series 2A	Series 3	Total
Maturity date	2014 November 30	2016 November 30	2017 June 30	
Interest rate	7.50%	6.35%	7.00%	
Conversion price per share	$4.08	$6.00	$4.20	
Carrying value at December 31, 2009	$ 62,686	$ 59,664	$ 63,250	$ 185,600
Conversion to shares (Note 12), net of costs	(4,473)	-	(345)	(4,818)
Amortization and accretion	943	35	-	978
Carrying value at December 31, 2010	$59,156	$59,699	$62,905	$181,760
Face value at December 31, 2010	$62,470	$59,967	$62,905	$185,342

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC (note 12).

10. Convertible Debentures (continued)

The Series 3 debentures are convertible into common shares of APUC at the option of the holder at a conversion price of $4.20 per common share, being a ratio of approximately 238.1 common shares per $1,000 principal amount of debentures. The debentures cannot be redeemed by APUC on or before December 31, 2012. During the period of January 1, 2013 until December 31, 2014, the Series 3 debentures may be redeemed by APUC provided that the weighted-average trading price of the underlying share price on the TSX for the 20 consecutive trading days is equal to or exceeds a price of $5.25 (125% of the conversion price of $4.20). During the period of January 1, 2015 until the Series 3 debentures' maturity, APUC can redeem the Series 3 debentures for 100% of the face value of the Series 3 Debentures with cash, or for 105% of the face value of the Series 3 debentures with additional shares.

11. Other long-term liabilities

Other long term liabilities consist of the following:

	2011	2010
Contingent consideration	$ 1,080	$ 1,198
Deferred water rights inducement	2,927	3,008
Customer deposits	2,483	1,985
Capital Leases		
Obligation for equipment leases. Interest rates varying from 1.90% to 5.80%, monthly interest and principal payments with varying dates of maturity from March 2012 to December 2014	501	535
Other	5,073	5,099
	12,064	11,825
Less: current portion	(1,641)	(1,011)
	$ 10,423	$ 10,814

12. Shareholders' Capital

Number of common shares:

	2011	2010
Common shares, beginning of period	95,422,778	93,064,120
Conversion and redemption of convertible debentures	15,300,824	1,178,478
Issuance pursuant to management internalization	-	1,180,180
Issuance of shares	25,399,178	-
Common shares, end of period	136,122,780	95,422,778

12. Shareholders' Capital (continued)

Authorized

APUC is authorized to issue an unlimited number of common shares. The holders of the common shares are entitled to dividends if, as and when declared by the Board of Directors (the Board); to one vote per share at meetings of the holders of common shares; and upon liquidation, dissolution or winding up of APUC to receive pro rata the remaining property and assets of APUC; subject to the rights of any shares having priority over the common shares, of which none are authorized or outstanding.

APUC is authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board of Directors of APUC. As at December 31, 2011, APUC does not have any issued and outstanding preferred shares.

On June 29, 2010, the Company issued 1,180,180 shares valued at $4,763 pursuant to the Management Internalization Agreement signed on December 21, 2009. The issuance of shares and final settlement was approved by the Company's shareholders at its annual general meeting held on June 23, 2010.

In 2010, $4,473 principal amount of New Series 1 Debentures were converted at the option of the holders at a price of $4.08 for each share into 1,096,336 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $4,094 has been recorded as share capital.

In 2010, $345 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 82,142 shares of APUC. The carrying amount of these debentures net of unamortized issuance costs and the bifurcated equity component totaling $311 has been recorded as share capital.

On April 1, 2011, APUC called for the redemption of the Series 1A Debentures on May 16, 2011 ("Redemption Date"). Prior to the Redemption Date, a principal amount of $60,339 of Series 1A Debentures were converted into 14,788,975 shares of APUC. On May 16, 2011, APUC redeemed the remaining Series 1A Debentures by issuing and delivering 430,666 APUC shares. On December 31, 2011, as a result of the Redemption there were no Series 1A Debentures outstanding.

During the year ended December 31, 2011, $10 principal amount of Series 2A Debentures were converted at the option of the holders at a price of $6.00 for each share into 1,666 shares of APUC.

During the year ended December 31, 2011, $334 principal amount of Series 3 Debentures were converted at the option of the holders at a price of $4.20 for each share into 79,517 shares of APUC.

Subsequent to year-end, the remaining principal amount of $59,967 of Series 2A Debentures were redeemed and converted into 10,322,518 shares of APUC.

Subsequent to the year end, $66 principal amount of Series 3 Debentures were converted at the option of the holders into 15,711 shares of APUC.

12. Shareholders' Capital (continued)

Shareholders' Rights Plan

On June 23, 2010, the Company's shareholders adopted a shareholders' rights plan (the "Rights Plan"). The Rights Plan has an initial term of three years. Under the Rights Plan, one right is issued with each issued share of the Company. The rights remain attached to the shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20 percent or more of the outstanding shares (subject to certain exceptions) of the Company, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase shares at a 50 percent discount from the then current market price. The rights provided under the Rights Plan are not triggered by any person making a "Permitted Bid", as defined in the Rights Plan.

Dividend reinvestment plan

The Company has a Common Shareholder Dividend Reinvestment Plan, which provides an opportunity for shareholders to reinvest dividends for the purpose of purchasing common shares. Additional Common Shares acquired through the reinvestment of cash dividends will be purchased in the open market or will be issued by APUC at a discount of up to 5% from the average market price, all as determined by the Company from time to time.

Employee Share Purchase Plan

In September 2011, the Company approved an employee share purchase plan ("ESPP") which commenced in October 2011. Eligible employees may have a portion of their earnings withheld to be used to purchase the Company's common shares. The Company will match a) 20% of employee contribution amount for the first five thousand dollars per employee contributed annually and 10% of employee contribution amount for contributions over five thousand dollars up to ten thousand dollars annually, for Canadian employees, and b) 15% of employee contribution amount for the first fifteen thousand dollar per employee contributed annually, for U.S. employees. Shares purchased through the Company match portion shall not be eligible for sale by the participant for a period of one year following the contribution date on which such shares were acquired. At the Company's option, the shares may be (i) issued to participants from treasury at the average share price or (ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares.

The Company uses the fair value based method to measure the compensation expense related to the Company's contribution. For the year ended December 31, 2011, a total of 7,176 common shares were issued to employees under the ESPP plan for a total compensation expense related to the ESPP in 2011 of $9.

12. Shareholders' Capital (continued)

Stock Option Plan

During 2010, the Company's shareholders approved a stock option plan (the "Plan") that permits the grant of share options to key officers, directors, employees and selected service providers. The aggregate number of shares that may be reserved for issuance under the Plan must not exceed 10% of the number of Shares outstanding at the time the options are granted. The number of shares subject to each option, the option price, the expiration date, the vesting and other terms and conditions relating to each option shall be determined by the Board from time to time. Dividends on the underlying shares do not accumulate during the vesting period. Option holders may elect to surrender any portion of the vested options which is then exercisable in exchange for the In-the-Money Amount. In accordance with the Plan, the In-The-Money Amount represents the excess, if any, of the market price of a share at such time over the option price, in each case such In-the-Money amount being payable by the Company in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these options are accounted for as equity awards.

In the case of qualified retirement, the Board may accelerate the vesting of the unvested options then held by the optionee at the Board's discretion. All vested options may be exercised within ninety days after retirement. In the case of death, the options vest immediately and the period over which the options can be exercised is one year. In the case of disability, options continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the plan. Employees have up to thirty days to exercise vested options upon resignation or termination.

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. The Company determines the fair value of options granted using the Black-Scholes option-pricing model. The risk-free interest rate is based on the zero-coupon Canada Government bond with a similar term to the expected life of the options at the grant date. Expected volatility was estimated based on the adjusted historic volatility of the Company's shares. The expected life was estimated to equal the contractual life of the options. The dividend yield rate was based upon recent historical dividends paid on APUC shares.

The following assumptions were used in determining the fair value of share options granted:

	2011	2010
Risk-free interest rate	3.0%	2.9%
Expected volatility	30%	29%
Expected dividend yield	5.3%	5.9%
Expected life	8 years	8 years
Weighted average grant date fair value per option	$ 0.99	$ 0.61

12. Shareholders' Capital (continued)

Stock option activity during the period is as follows:

	Number of shares		Weighted average exercise price	Weighted average remaining contractual term		Aggregate intrinsic value
Balance at January 1, 2011	1,160,204	$	4.05	7.62	$	1,056
Granted	1,326,900		5.38	8.00		22
Balance at December 31, 2011	2,487,104	$	4.76	6.96	$	4,134
Exercisable at December 31, 2010	386,735	$	4.05	6.62	$	917

On March 14, 2012, 1,194,606 stock options were granted to senior executives of APUC which allow for the purchase of common shares at a price of $6.22.

Directors Deferred Share Units

In June 2011, the Shareholders approved a Deferred Share Unit Plan. Under the plan, non-employee directors of the Company may elect annually to receive all or any portion of their compensation in Deferred Share Units ("DSUs") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Company's common share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of the Company. As the Company expects to settle these instruments in cash, these DSUs are accounted for as liability awards and dividends accumulated are recognized as additional compensation cost. The DSU liabilities are marked-to-market at the end of each period based on the common share price at the end of the period. As at December 31, 2011, no DSUs had been issued.

12. Shareholders' Capital (continued)

Performance Share Units

The Company approved a performance share unit plan to its employees as part of the Company's long-term incentive program. Performance share units ("PSUs") are granted annually for three-year overlapping performance cycles. PSUs vest at the end of the three-year cycle and will be calculated based on established performance criteria. At the end of the three-year performance periods, the number of shares issued can range from 0% to 144% of the number of PSUs granted. Dividends accumulating during the vesting period are converted to PSUs based on the market value of the shares on that date and are recorded in equity as the dividend's are declared. None of these PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire. The PSUs provide for settlement in cash or shares at the election of the Company. As the Company does not expect to settle these instruments in cash, these PSUs will be accounted for as equity awards. Compensation expense associated with PSUs is recognized ratably over the performance period based on the Company's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest

A summary of the PSUs activity follows:

	Employees PSUs Outstanding
December 31, 2010	-
Granted	21,123
December 31, 2011	21,123

A summary of the non-vested PSUs follows:

	Employees PSUs	
	Shares	Weighted Average Grant-Date Fair Value
Non-vested at January 1, 2011	-	$ -
Granted	21,123	5.62
Non-vested at December 31, 2011	21,123	$5.62

Share-based compensation

For the year ended December 31, 2011, APUC recorded $769 (2010 - $108) in total share-based compensation expense. No tax deduction was realized in the current year. The compensation expense is recorded as part of the operating expenses in the Consolidated Statement of Operations. The portion of share-based compensation costs capitalized as cost of construction is insignificant.

As at December 31, 2011, total unrecognized compensation costs related to non-vested options and share unit awards were $1,216 and $70 respectively, which are expected to be recognized over a period of 1.76 years and 2 years respectively.

13. Cash dividends

All dividends of the Company are made on a discretionary basis as determined by the Board of the Company. For the year ended December 31, 2011, the Company declared cash dividends to shareholders totaling $32,426 (2010 - $22,765) or $0.24 per common share (2010 - $0.24 per common share).

On November 14, 2011, the Board declared a dividend on the Company's shares of $0.07 per share payable on January 16, 2012 to the shareholders of record on December 30, 2011 for the period from October 1, 2011 to December 31, 2011.

14. Income Taxes

The provision for income taxes in the consolidated statements of operations represents an effective tax rate different than the Canadian enacted statutory rate of 28.25% (2010 - 31%). The differences are as follows:

	2011	2010
Expected income tax expense / (recovery) at Canadian statutory rate	$1,204	$ (45)
Increase (decrease) resulting from:		
Recognition of deferred credit	(6,581)	(6,636)
Differences in tax rates in subsidiaries and changes in tax Rates	(861)	(202)
Change in valuation allowances	(16,834)	(5,979)
Foreign exchange on intercompany items	2,250	(6,228)
Non-taxable corporate dividend	(1,418)	(1,191)
Non-controlling interests share of income	(1,317)	-
Other permanent difference	518	(510)
Income tax recovery	$ (23,039)	$(20,791)

For the years ended December 31, 2011 and 2010, income/(loss) before taxes consists of the following:

	2011	2010
Canadian operations	$ (5,242)	$ (6,405)
U.S. operations	9,505	4,007
	$ 4,263	$ (2,398)

14. Income Taxes (continued)

As a result of the business combination transaction in 2009, APUC recorded certain additional tax attributes. These tax attributes have been recognized to the extent management believes they are more likely than not to be realized. The excess of the carrying amount of the tax attributes recorded over the consideration was reflected as a deferred credit of $55,647 on the transaction date. The deferred credit is being recognized in income as a deferred income tax recovery in relative proportion to the amount of the related deferred tax assets that are utilized in the period.

Income tax expense (recovery) attributable to income/(loss) consists of:

	Current	Deferred	Total
Year ended December 31, 2011			
Canada	$ 268	$ (1,936)	$ (1,668)
United States	32	(21,403)	(21,371)
	$ 300	$ (23,339)	$ (23,039)
Year ended December 31, 2010			
Canada	200	(1,081)	(881)
United States	(269)	(19,641)	(19,910)
	$ (69)	$ (20,722)	$ (20,791)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2011 and 2010 are presented below:

	2011	2010
Deferred income tax assets:		
Non-capital loss, investment tax credits, currently non-deductible interest expenses, and financing costs	$ 133,625	$ 120,973
Unrealized foreign exchange difference on intercompany notes	-	17,860
Customer advances in aid of construction	6,610	5,559
Regulatory liabilities	4,313	-
Foreign exchange hedges and interest rate swaps	2,233	1,459
Total deferred income tax assets	146,781	145,851
Less: Valuation allowance	(15,063)	(31,896)
Total deferred income tax assets	131,718	113,955
Deferred tax liabilities:		
Property, plant and equipment	(96,158)	(96,554)
Intangible assets	(7,812)	(7,639)
Other	(1,009)	(1,697)
Total deferred income tax liabilities	(104,979)	(105,890)
Net deferred income tax assets	$ 26,739	$ 8,065

14. Income taxes (continued)

The valuation allowance for deferred tax assets as of December 31, 2011 and 2010 was $15,062 and $31,896, respectively. The net change in the total valuation allowance was a decrease of $16,834 in 2011 and a decrease of $5,979 in 2010. The valuation allowance at December 31, 2011 was primarily related to operating losses that, in the judgment of management, are not more likely than not to be realized. In assessing the realizability of deferred tax assets, management considers whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities (including the impact of available carry back and carry forward periods), projected deferred taxable income, and tax-planning strategies in making this assessment.

Deferred income taxes are classified in the financial statements as:

	2011	2010
Current deferred income tax asset	$ 13,022	$ 14,015
Non-current deferred income tax asset	67,671	74,006
Current deferred income tax liability	(723)	(514)
Non-current deferred income tax liability	(53,231)	(79,442)
	$ 26,739	$ 8,065

As at December 31, 2011, the Company had non-capital losses carry forwards available to reduce future year's taxable income, which expire as follows:

Year of expiry	Non-capital losses carry forwards
2015	$ 28,406
2026 and onwards	239,823
	$ 268,229

15. Related party transactions

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

APUC has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a triple net basis. Base lease costs for year ended December 31, 2011 were $327 (2010 - $327).

APUC utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI, Algonquin Airlink Inc. In 2004, APUC entered into an agreement and remitted $1,300 to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for APUC's business use of the aircraft. Under the terms of this arrangement, APUC has priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft. During the year, APUC incurred costs in connection with the use of the aircraft of $453 (2010 - $430) and amortization expense related to the advance against expense reimbursements of $274 (2010 - $112). At December 31, 2011, the remaining amount of the advance was $279 (2010 - $554) and is recorded in other assets.

15. Related party transactions (continued)

Affiliates of APMI hold 60% of the outstanding Class B limited partnership units issued by the St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of APUC and the legal owner of the St. Leon facility. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing June 17, 2008, increasing by 2.5% every 5 years to a maximum of 10% by year 15. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The related holders of the Class B units received cash distributions of $314 for the year ended December 31, 2011 (2010 - $266). APUC and the Class B holders have executed an agreement which outlines the relationship of the parties in relation to the St. Leon II expansion of the St Leon facility ("Expansion Agreement"). The terms of the Expansion Agreement allow APUC to expand the St Leon project on a "no-net-harm-basis" to the Class B holders and provide APUC with the full economic benefit of such expansion.

APMI is one of the two original developers of Red Lily I (note 5(b)) and both developers are entitled to a royalty fee based on a percentage of operating revenue and a development fee from the equity owner of Red Lily I. The royalty fee is initially equal to 0.75% of gross energy revenue, increasing every five years up to 2% after twenty-five years. During the year, APUC acquired APMI's interest in this royalty for an amount of $600. This amount has been recorded as a purchase of intangible assets and the amount owing to APMI is included in accrued liabilities at December 31, 2011.

Staff managed by APUC have historically operated an additional three hydroelectric generating facilities not owned by APUC where Senior Executives hold an equity interest. Effective January 1, 2011, management of these facilities is now being undertaken by Algonquin Power Systems Inc. ("APS") which is an entity where Senior Executives hold equity interests. APUC and APS agreed to provide some transition services to each other until December 31, 2011. Costs for providing such transition services are intended to be on a cost recovery basis with no mark-up.

As at December 31, 2011, included in amounts due from related parties is $663 (2010 - $718) owed to APUC from APMI and included in amounts due to related parties is $1,795 (2010 - $901) owed to APMI. These amounts arise from the transactions described above.

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

In 2010, APUC entered into a one year contract with a subsidiary of Emera to provide lead market participant services for fuel capacity and forward reserve markets in ISO NE for the Windsor Locks facility. During 2011 APUC paid U.S. $260 (2010 - $196) in relation to this contract. In the same period, APUC provided a corporate guarantee to a subsidiary of Emera in an amount of U.S. $1,000 in conjunction with this contract.

On December 21, 2010, a subsidiary of Emera acquired Maine & Maritimes Corporation, the parent company of Maine Public Service Company ("MPS"). For 2011, the Energy Services Business sold electricity amounting to $6,564 (2010 - $0). In the same period, APUC provided a corporate guarantee to MPS in an amount of U.S. $3,000 and a letter of credit in an amount of U.S $100, primarily in conjunction with a three year contract to provide standard offer service to commercial and industrial customers in Northern Maine.

15. Related party transactions (continued)

As of December 31, 2011, included in amounts due from related parties is $1,612 (2010 - $0) owed from Emera related to the unpaid contribution of their share of Liberty Energy (California) costs.

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

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

Subsequent to December 31, 2011, APUC and the Parties reached an Agreement to resolve a number of the historic joint business associations between APUC and the Parties. The transaction is subject to finalization of definitive agreements which are expected to be completed in the second quarter of 2012.

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

16. Interest, dividend and other income

Interest, dividend and other income includes the following items:

	2011	2010
Interest income	$ 2,533	$ 1,138
Dividend income	2,928	2,928
Equity income	193	431
Other	5	667
	$ 5,659	$ 5,164

17. Other revenue

Other revenue consists of the following:

	2011	2010
Hydro mulch sales	$1,352	$1,318
Red Lily development fees	209	209
Red Lily royalty income and supervisory fees	947	-
Red Lily construction services fees and natural gas sales	757	1,804
Gain on sale of assets	358	-
Other	20	-
	$ 3,643	$ 3,331

18. Commitments and Contingencies

Land and Water Lease Commitments:

Certain of the Company's operating entities have entered into agreements to lease either land, water rights or both that are used in the generation of electricity or to pay, in lieu of property tax, an amount based on electricity production. The terms of these leases have varying maturity dates that continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. APUC incurred costs of $2,654 during 2011 (2010 - $2,231) in respect of these agreements for all of its operating entities.

Contingencies:

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

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

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

The APUC subsidiary believes it is held harmless in its water lease from this decision. The Federal Authorities have decided not to appeal this decision to the Supreme Court of Canada. APUC and Seaway Management are now required to go back to the Superior Court of Quebec which will determine the amount of money reimbursable by Seaway Management to APUC pursuant to the terms of the Water Lease. As a result, the probability of loss, if any, and its quantification cannot be estimated at this time but could range from $nil to $5.4 million. Accordingly, no accruals for amounts owed or recoverable in respect of the water lease dues already paid to Seaway Management have been recorded in the financial statements. Conversely, the Company accrued $1,000 of water lease owed to Québec AG for the years 2008 to 2011, which years are subsequent to those covered by the Court Decision and might not be subject to the legal right of offset. Probable amounts recoverable from the Federal Authorities of $300 related to these years were also recorded in 2011.

18. Commitments and Contingencies (continued)

Other Commitments:

In addition to the commitments related to the proposed acquisitions disclosed in note 3 the following significant commitments exist at December 31, 2011.

Legislation in the Province of Quebec requires technical assessments be made of all dams within the province and remediation of any technical deficiencies identified in accordance with the assessment. APUC is in the process of conducting the assessments as required. Based on assessments to date, some of which are preliminary, APUC has estimated the remaining potential remedial measures involving capital expenditures to be approximately $16,900 which may be required to comply with the legislation and which would be invested over a five year period or longer.

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

	2012	2013	2014	2015	2016	Thereafter	Total
Long term service agreements	$4,559	$4,072	$4,153	$4,236	$4,321	$73,008	$94,349
Purchased power	45,053	45,155	46,375	45,867	45,053	-	227,503
Capital projects	7,871	-	-	-	-	-	7,871
Operating leases	939	609	369	282	20	-	2,219
Total	**$58,422**	**$49,836**	**$50,897**	**$50,385**	**$49,394**	**$73,008**	**$331,942**

Liberty Utilities (West) has entered into a five year all-purpose PPA with NV Energy to provide its full electric requirements at NV Energy's "system average cost" rates. The PPA has an effective starting date of January 1, 2011 with a five year renewal option. The commitment amounts included in the table above are based on market prices as of December 31, 2011. However, the effects of purchased power unit cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

19. Basic and diluted net earnings per share

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

	2011	2010
Weighted average shares – basic	116,712,934	94,338,193
Dilutive effect of share-based awards	249,854	-
Weighted average shares – diluted	116,962,788	94,338,193

The shares potentially issuable as a result of the convertible debentures and 1,326,900 stock options (2010 –1,160,204) are excluded from this calculation as they are anti-dilutive.

20. Non-cash operating items

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

	2011	2010
Accounts receivable	$ (11,674)	$ (6,817)
Related party balances	145	-
Supplies and consumable inventory	(1,087)	-
Income tax receivable	(133)	1,143
Prepaid expenses	(2,071)	1,153
Accounts payable	3,991	5,050
Accrued liabilities	9,010	-
Current income tax liability	207	195
Net regulatory assets and liabilities	70	(809)
	$ (1,542)	$ (85)

21. Segmented Information

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

Within APCo there are three divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops the Company's greenfield power generation projects as well as any expansion of the Company's existing portfolio of renewable energy and thermal energy facilities.

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

Operational segments

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

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

21. Segmented Information (continued)

Operational Segments (continued)

	Year ended December 31, 2011							
	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non-regulated energy sales	$87,566	$46,666	$134,232	$ -	$ -	$ -	$ -	$ 134,232
Regulated energy sales and distribution	-	-	-	-	77,368	77,368	-	77,368
Waste disposal fees	-	16,406	16,406	-	-	-	-	16,406
Water reclamation and distribution	-	-	-	44,989	-	44,989	-	44,989
Other revenue	2,291	1,352	3,643	-	-	-	-	3,643
Total revenue	89,857	64,424	154,281	44,989	77,368	122,357	-	276,638
Operating expenses	29,802	44,485	74,287	22,720	62,511	85,231	38	159,556
	60,055	19,939	79,994	22,269	14,857	37,126	(38)	117,082
Depreciation of property, plant and equipment	(16,903)	(10,684)	(27,587)	(7,993)	(3,813)	(11,806)	-	(39,393)
Amortization of intangible assets	(3,007)	(2,735)	(5,742)	(691)	-	(691)	-	(6,433)
Administration expenses	(10,719)	(700)	(11,419)	(342)	(798)	(1,140)	(4,975)	(17,534)
Write down of long-lived assets	(2,032)	(13,430)	(15,462)	(1,058)	-	(1,058)	-	(16,520)
Gain on foreign exchange	-	-	-	-	-	-	652	652
Interest expense	(8,128)	(1,688)	(9,816)	(5,189)	(4,526)	(9,715)	(10,910)	(30,441)
Interest, dividend and other income	2,143	(6)	2,137	488	-	488	3,034	5,659
Acquisition related costs	-	-	-	(2,301)	(466)	(2,767)	(198)	(2,965)
Loss on derivative financial instruments	(1,068)	-	(1,068)	-	-	-	(4,776)	(5,844)
Earnings / (loss) before income taxes	$ 20,341	$ (9,304)	$ 11,037	$ 5,183	$ 5,254	$ 10,437	$ (17,211)	$ 4,263
Property, plant and equipment	$ 423,884	155,507	579,391	208,073	158,492	366,565	-	945,956
Intangible assets	25,863	7,088	32,951	-	22,318	22,318	-	55,269
Total assets	482,543	176,269	658,812	252,514	188,399	440,913	182,863	1,282,588
Capital expenditures	25,610	13,601	39,211	10,906	10,261	21,167	367	60,745
Acquisition of operating entities	-	-	-	1,253	98,805	100,058	-	100,058

21. Segmented Information (continued)

Operational Segments (continued)

Year ended December 31, 2010	Algonquin Power			Liberty Utilities			Corporate	Total
	Renewable Energy	Thermal Energy	Total	South	West	Total		
Revenue								
Non regulated energy sales	$ 80,117	$49,860	$129,977	$ -	$ -	$ -	$ -	$129,977
Waste disposal fees	-	9,039	9,039	-	-	-	-	9,039
Water reclamation and distribution	-	-	-	38,011	-	38,011	-	38,011
Other revenue	2,122	1,209	3,331	-	-	-	-	3,331
Total revenue	82,239	60,108	142,347	38,011	-	38,011	-	180,358
Operating expenses	29,481	43,817	73,298	22,199	-	22,199	-	95,497
	52,758	16,291	69,049	15,812	-	15,812	-	84,861
Depreciation of property, plant and equipment	(17,233)	(11,243)	(28,476)	(7,820)	-	(7,820)	(175)	(36,471)
Amortization of intangible assets	(6,670)	(2,774)	(9,444)	(700)	-	(700)	-	(10,144)
Administration expenses	(4,674)	(1,825)	(6,499)	(1,890)	-	(1,890)	(6,497)	(14,886)
Write down of long-lived assets	(1,836)	(656)	(2,492)	-	-	-	-	(2,492)
Foreign exchange gain	-	-	-	-	-	-	528	528
Interest expense	(7,742)	(770)	(8,512)	(1,911)	-	(1,911)	(14,416)	(24,839)
Interest, dividend and other income	783	633	1,416	149	-	149	3,599	5,164
Acquisition related costs	-	-	-	-	-	-	(3,015)	(3,015)
Loss on derivative financial instruments	(5,486)	-	(5,486)	-	-	-	4,383	(1,103)
Earnings / (loss) before income taxes	9,900	(344)	9,556	3,640	-	3,640	(15,593)	(2,397)
Property, plant and equipment	$412,159	$149,837	$561,996	$199,251	-	$199,251	$493	$761,740
Intangible assets	28,287	23,104	51,391	22,495	-	22,495	-	73,886
Total assets	467,589	194,906	662,495	237,513	-	237,513	116,941	1,016,949
Capital expenditures	2,331	11,554	13,885	6,644	-	6,644	260	20,789
Acquisition of operating entities	40,281	-	40,281	2,120	1,996	4,116	-	44,397

21. Segmented Information (continued)

Operational Segments (continued)

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2011 or 2010: Hydro Québec 17% (2010 - 14%), Pacific Gas and Electric 11% (2010 - 10%), Manitoba Hydro 16% (2010 – 15%), and AES 15% (2010 - 18%). The Company has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.
APUC and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2011	2010
Revenue		
Canada	$ 88,900	$ 72,360
United States	187,738	107,998
	$ 276,638	$ 180,358
Property, plant and equipment		
Canada	$ 474,094	$ 464,783
United States	471,862	296,957
	$ 945,956	$ 761,740
Intangible assets		
Canada	$ 25,863	$ 43,305
United States	29,406	30,581
	$ 55,269	$ 73,886
Other assets		
Canada	$ 3,577	$ 1,415
United States	-	1,940
	$ 3,577	$ 3,355

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

22. Financial instruments

a) Fair Value of financial instruments

	2011 Carrying amount	2011 Fair Value	2010 Carrying amount	2010 Fair value
Cash and cash equivalents	$ 72,887	$ 72,887	$ 4,749	$ 4,749
Short-term investments	833	833	3,674	3,674
Accounts receivable and due from related parties	46,669	46,669	26,593	26,593
Restricted cash	4,693	4,693	3,564	3,564
Notes receivable	24,534	24,534	18,744	18,744
Total financial assets	$ 149,616	$ 149,616	$ 57,324	$ 57,324
Accounts payable and due to related parties	10,177	10,177	3,716	3,716
Accrued liabilities	47,102	47,102	29,534	29,534
Dividends payable	9,566	9,566	5,719	5,719
Long-term liabilities	332,716	338,264	259,958	262,117
Convertible debentures	122,297	162,195	181,760	216,769
Interest rate swaps	6,975	6,975	5,440	5,440
Energy forward purchase contracts	1,169	1,169	378	378
Foreign exchange contracts	-	-	45	45
Total financial liabilities	$ 530,002	$ 575,448	$ 486,550	$ 523,718

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

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

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

Advances in aid of construction have a carrying value of $75,151 (2010 - $55,115) at December 31, 2011. Portions of these non-interest bearing instruments are payable annually through 2026 and amounts not paid by the contract expiration dates become nonrefundable. Their relative fair values cannot be accurately estimated because future refund payments depend on several variables, including new customer connections, customer consumption levels, and future rate increases. However, the fair value of these amounts would be less than their carrying value due to the non-interest bearing feature.

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.

22. Financial instruments (continued)

b) Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities accounted for at fair value at December 31, 2011 are as follows:

	Level 1	Level 2	Level 3	Total
Derivative liabilities:				
Energy forward purchase contracts	$ -	$ (1,169)	$ -	$ (1,169)
Interest rate swap	-	(6,975)	-	(6,975)
	$ -	$ (8,144)	$ -	$ (8,144)

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 years ended December 31, 2011 or 2010.

The fair value of derivative instruments is estimated using forward curves obtained from brokers and market participants, net of estimated credit risk.

The Red Lily conversion option (note 5 (a)) 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, discount rate and estimated cash flows. There was no change in fair value of $0 during the years ended December 31, 2011 or 2010.

22. Financial instruments (continued)

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

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

	2011	2010
Change in unrealized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ (45)	$ (1,424)
Interest rate swaps	1,536	(2,787)
Energy forward purchase contracts	833	(2,931)
Total change in unrealized loss/(gain) on derivative financial instruments	$ 2,324	$ (7,142)
Realized loss/(gain) on derivative financial instruments:		
Foreign exchange contracts	$ 691	$ (620)
Interest rate swaps	2,138	5,929
Energy forward purchase contracts	691	2,936
Total realized loss on derivative financial instruments	$ 3,520	$ 8,245
Loss on derivative financial instruments	$ 5,844	$ 1,103

(d) Risk Management

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

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

Credit Risk

Credit risk is the risk of an unexpected loss if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Company's financial instruments that are exposed to concentrations of credit risk are primarily cash and cash equivalents, short term investments, accounts receivable and notes receivable. The Company limits its exposure to credit risk with respect to cash equivalents by ensuring available cash is deposited with its senior lenders in Canada all of which have a credit rating of A or better. The Company does not consider the risk associated with accounts receivable to be significant as over 80% of revenue from Power Generation is earned from large utility customers having a credit rating of BBB or better, and revenue is generally invoiced and collected within 45 days.

22. Financial instruments (continued)

The remaining revenue is primarily earned by the Utility Services business unit which consists of water and wastewater utilities in the United States. In this regard, the credit risk related to Utility Services accounts receivable balances of U.S. $4,996 is spread over thousands of customers. The Company has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers. In addition the state regulators of the Company's utilities allow for a reasonable bad debt expense to be incorporated in the rates and therefore ultimately recoverable from rate payers.

As at December 31, 2011 the Company's exposure to credit risk for these financial instruments was as follows:

	December 31, 2011	
	Canadian $	**US $**
Cash and cash equivalents and restricted cash	$ 69,108	$ 9,149
Short term investments	833	-
Accounts receivable	14,229	29,912
Allowance for Doubtful Accounts	-	(251)
Note Receivable	22,478	2,021
	$ 106,648	$ 40,831

There are no material past due amounts in accounts receivable.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity risk is to ensure, to the extent possible, that it will always have sufficient liquidity to meet liabilities when due. As at December 31, 2011, in addition to cash on hand of $72,887 the Company had $80,400 available to be drawn on its senior debt facility. The senior credit facility contains covenants which may limit amounts available to be drawn. The Company`s liabilities mature as follows:

	Due less than 1 year	**Due 2 to 3 years**	**Due 4 to 5 years**	**Due after 5 years**	**Total**
Long term debt obligations	$ 1,624	$ 3,725	$ 9,556	$ 317,811	$ 332,716
Convertible Debentures	59,726	-	-	62,571	122,297
Interest on long term debt	25,571	40,241	37,250	124,807	227,869
Accounts Payable and due to related parties	10,177	-	-	-	10,177
Accrued liabilities	47,102	-	-	-	47,102
Derivative financial instruments:					
Interest Rate Swaps	2,935	4,113	1,096	-	8,144
Capital Lease Payments	231	260	10	-	501
Other obligations	1,063	516	516	7,681	9,776
Total obligations	$148,429	$ 48,855	$48,428	$ 512,870	$758,582

22. Financial instruments (continued)

Foreign Currency Risk

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

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

Interest Rate Risk

The Company is exposed to interest rate fluctuations related to certain of its floating rate debt obligations, including certain project specific debt and its revolving credit facility, its interest rate swaps as well as interest earned on its cash on hand. The Company does not currently hedge that risk.

In connection with the project debt at the St. Leon facility which was repaid during 2011, APCo previously entered into an interest rate swap to hedge the floating interest rate on the project debt. Under the terms of the swap, the Company pays a fixed interest rate of 4.47% on a notional amount of $67.8 million and receives floating interest at 90 day CDOR, up to the expiry of the swap in September 2015. At December 31, 2011, the estimated fair value of the interest rate swap was a liability of $6,975 (2010 –liability of $5,440). 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.

Market Risk

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

This risk is mitigated though the use of short term financial forward energy purchase contracts which are derivative instruments. In January 2011, APUC entered into electricity derivative contracts with Nextera (“counterparty”) for a term ending February 2014, which are net settled fixed-for-floating swaps whereby APUC will pay a fixed price and receive the floating or indexed price on a notional quantity of 162,128 MW-hrs of energy over the remainder of the contact term at an average rate of approximately $51.40 per MW-hr. The estimated fair value of these forward energy hedge contracts at December 31, 2011 was a net liability of $1,169 (December 31, 2010 - $nil).

23. Capital disclosures

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

The Company's objectives when managing capital are:

- To maintain appropriate debt and equity levels in conjunction with standard industry practices and to limit financial constraints on the use of capital.
- To ensure capital is available to finance capital expenditures sufficient to maintain existing assets.
- To ensure generation of cash is sufficient to fund sustainable distributions to Unitholders as well as meet current tax and internal capital requirements.
- To maintain sufficient cash reserves on hand to ensure sustainable dividends made to shareholders.
- To have proper credit facilities available for ongoing investment in growth and investment in development opportunities.

The Company monitors its cash position on a regular basis to ensure funds are available to meet current operating as well as capital expenditures. In addition, the Company regularly reviews its capital structure to ensure its individual business units are using a capital structure which is appropriate for their respective industries.

24. Comparative figures

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

NOTES

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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

The Management Group

Ian Robertson, Chief Executive Officer
Chris Jarratt, Vice-Chair
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