



powering a cleaner tomorrow

RUN OF RIVER POWER INC.

Management Discussion and Analysis

Three Months and Nine Months Ended September 30, 2009

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The following MD&A dated November 27, 2009 should be read in conjunction with the unaudited Interim Consolidated Financial Statements for the nine months ended September 30, 2009 of Run of River Power Inc. (“Corporation” or “ROR”) and with the audited Consolidated Financial Statements dated December 31, 2008 and December 31, 2007. The Corporation reports its financial position, results of operations and cash flows in accordance with Canadian generally accepted accounting principles (“GAAP”) in Canadian dollars. This MD&A was prepared with information available as of November 27, 2009. Additional information and disclosure relating to the Corporation can be found on SEDAR at www.sedar.com or on the Corporation’s website at www.runofriverpower.com.

FORWARD-LOOKING STATEMENTS

This MD&A includes forward-looking statements. All statements other than statements of historical facts contained in this MD&A, including statements regarding the future financial position, business strategy, plans and objectives of management for future operations, are forward-looking statements. The words “believe”, “may”, “will”, “estimate”, “continue”, “anticipate,” “intend”, “should”, “plan”, “expect” and similar expressions, as they relate to the Corporation, are intended to identify forward-looking statements. The Corporation has based these forward-looking statements on the current expectations and projections about future events and financial trends that it believes may affect its financial condition, results of operations, business strategy and financial needs. These forward-looking statements are subject to a number of risks, uncertainties and assumptions as described elsewhere in this MD&A.

Other sections of this MD&A may include additional factors that could adversely affect the business and financial performance. Moreover, the Corporation operates in a very competitive and rapidly changing business environment. New risk factors emerge from time to time and it is not possible for management to predict all risk factors, nor can the Corporation assess the impact of all factors on its business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

Readers should not rely upon forward-looking statements as predictions of future events or performance. The Corporation cannot provide assurance that the events and circumstances reflected in the forward-looking statements will be achieved or will occur. Although the Corporation believes that the expectations reflected in the forward-looking statements are reasonable, the Corporation cannot guarantee future results, levels of activity, performance, or achievements.

OVERVIEW

Run of River Power Inc. develops renewable, sustainable energy through its portfolio of run-of-river and biomass projects in British Columbia. The Corporation’s first run-of-river power project in operation is an Eco Logo® certified 7.6 MW facility based on Brandywine Creek near Whistler, BC. The facility began producing electricity in 2005, with all of its production sold to BC Hydro under a 20 year Electricity Purchase Agreement (“EPA”). Currently the Brandywine facility is Run of River’s sole source of revenue; however, 639 MW of run-of-river power projects and 94 MW of biomass power projects are currently in various stages of development.

The Corporation and its wholly owned subsidiaries: 1554675 Ontario Limited (currently inactive), Rockford Energy Corporation (“Rockford”), Jascott Holdings Corp. (“Jascott”), Northwest Cascade Power Ltd.. (“NWCP”), Crawford Energy Corp., Raffuse Energy Corporation, Skookum Energy Corp., Sea to Sky Power Corporation, Western Biomass Power Corp (“Western Biomass”) and its 80% owned subsidiary Pacific Northwest Biomass Corporation (“PNBC”) are incorporated in the Province of British Columbia, Canada. The

Corporation is a reporting issuer in British Columbia and Alberta and its common shares trade on the TSX Venture Exchange (TSX-V) under the symbol ROR.

The Corporation's 38 run-of-river power sites are comprised of five clusters that will have an estimated capacity of 639 MW and an annual output of 2,277 GWh of electricity. Two power clusters, the Mamquam Cluster and Upper Pitt Cluster, comprised of 11 projects, are strategically located near the lower mainland of BC where the demand for power is the greatest. These two clusters will have an estimated capacity of 202 MW and an annual output of 777 GWh of electricity. The remaining three power clusters are located in central BC in the Klinaklini, Mosley and Bella Cooola watersheds, all of which are accessed via Highway 20. They comprise 27 projects that will have a combined estimated capacity of 437 MW and an annual output of 1,500 GWh of electricity.

In 2005 the Corporation acquired the Upper Pitt Cluster that comprises projects covering eight tributaries of the Upper Pitt River. The Upper Pitt River is located about 40 kilometres from Vancouver and drains into an area immediately to the east of the Mamquam River Watershed where the Corporation has other projects. A comprehensive development plan is being advanced for the 25 MW Skookum Creek project in the Mamquam Cluster with the Upper Pitt Cluster accounting for a further 155 MW. These run-of-river projects use the proximity of their locations to transmission infrastructure, and other projects within their clusters, to take advantage of economies of scale. All of these projects are expected to utilize the same transmission line, subject to the necessary permitting being obtained, which will result in shared infrastructure costs and minimized visual impacts.

The Corporation is pursuing two biomass initiatives: the 60 MW Tsilhqot'in Biomass Power Project, to be located 75 kilometres west of Williams Lake in Hanceville, BC and the 34 MW Suskwa Biomass Power Project, to be located near New Hazelton, BC in the northwest corner of the province. Combined these projects will generate 94 MW of capacity and generate approximately 772 GWh of electricity annually.

OUTLOOK

Federal

In April 2007, the Government of Canada unveiled its action plan to reduce greenhouse gases and air pollution. The proposed framework for the Clean Air Regulatory Agenda ("CARA") targets stabilization, then reduction of greenhouse gases and air pollutants. Short-term targets are to be expressed as reductions from 2006 levels. For existing facilities, emission intensity reduction targets are to be based on an improvement of 6% each year from 2007 to 2010 (for cumulative reduction of 18% of 2006 levels by 2010). Every year thereafter, a 2% continuous emission-intensity improvement will be required, resulting in an industrial emission-intensity reduction of 26% by 2015. Carbon-emitting electricity generation companies are expected to meet their obligations by reducing their own emissions, contributing to a technology fund, using emissions trading or offsets, or by using a one-time credit for verifiable early action undertaken between 1992 and 2006. Also, in March 2008 the Government of Canada released draft regulations addressing GHG emissions. The draft has been issued for a period of consultation, after which the federal government is expected to finalize the regulations, at an as yet undetermined date. The federal government's actions on GHG emissions and other pollutants are not projected to have a negative impact on the Corporation's existing generation portfolio. However, it is reasonable to assume that such regulation will negatively impact the cost structure of competitors utilizing carbon-based fuels for electricity generation.

Provincial

Despite its vast hydroelectric resources, over the last several years BC has become a net importer of electricity and is facing a very significant supply-demand gap. BC Hydro has projected energy generation deficits of up to 1400 MW by 2015. In response to this growing shortfall, the provincial government enacted its Energy Plan in 2007 to meet the shortfall through conservation and acquisition of clean and renewable energy resources. In addition to becoming energy self-sufficient by 2016, the BC Energy Plan also includes the goals of having

90% of the province's electricity generated from clean sources, as well as having all new generation with zero net Greenhouse Gas (GHG) emissions, with overall emissions dropping 33% by 2020 from 2007 levels. In supporting the BC Energy Plan, the government initiated three programs for power acquisition. These include:

- The Clean Call for Power, for projects greater than 10MW;
- The Standing Offer Program, a standardized, fast track program for projects smaller than 10MW; and
- The Bioenergy Call for Power, consistent with the Bioenergy Strategy released on January 31, 2008, for projects using beetle-killed fibre and other sources.

On June 11, 2008, BC Hydro issued a request for proposal under the Clean Call for Power for 5,000 GWh per year of seasonal and hourly firm energy to help ensure that the Province of BC has sufficient electricity to meet its electricity needs by 2016. The final evaluation and EPA awards for the 2008 Clean Power Call were scheduled to occur by the end of June 2009 following approval of BC Hydro's 2008 Long Term Acquisition Plan ("2008 LTAP") by the British Columbia Utilities Commission ("BCUC"). The BCUC decision was delayed until July 27, 2009. In it, the BCUC rejected the 2008 LTAP as being deficient in a number of respects and concluded that generation from the gas-fired Burrard Thermal Plant should be increased to 5,000 GWh/yr. It was the Commission Panel's position that the 2008 LTAP was not in the public interest.

On July 30, 2009, the Provincial Minister for Energy, Mines and Petroleum Resources stated unequivocally that the BC Government has no plans to increase the use of the Burrard Thermal Plant. Furthermore, the Provincial Energy Plan of energy self-sufficiency by 2016 supports BC Hydro's plan to replace the firm energy supply from the Burrard Thermal Plant with clean, renewable energy. The 2008 Climate Action Plan of the BC Government calls for a 33% reduction in greenhouse gas emissions and for the Burrard Thermal Plant, the single largest source of such emissions, to be replaced by 2014. On October 28, 2009, the BC Government issued an order-in-council directing that BC Hydro and the BCUC must use the Burrard Thermal Plant for only 900 MW of emergency capacity.

On November 2, 2009, the Premier of British Columbia announced that the Province will establish a Green Energy Advisory Task Force with the mandate to ensure that BC remains a leader in clean and renewable energy by developing its resources, maximizing its opportunities and establishing its potential as the supplier of choice for clean power. The task force groups will consist of clean-energy experts, energy consultants, climate experts, leading academics, First Nation representatives and environmentalists. The Green Energy Advisory Task Force will be comprised of four advisory task force groups that will address:

- Procurement and Regulatory Reform
- Carbon Pricing, Trading and Export Market Development
- Community Engagement and First Nations Partnerships
- Resource Development

On November 17, 2009 BC Hydro announced that it will advance discussions with proponents of 47 projects and that 21 projects will not proceed further at this stage due to higher levels of proposed risk. BC Hydro notified the Corporation that its 25 MW Mamquam project would be proceeding to the next stage. BC Hydro also advised ROR that uncertainty related to the transmission route posed sufficient risk to the project such that the Upper Pitt proposal would not be proceeding to the next stage of the 2008 Clean Power Call. The Corporation intends to solve the transmission routing and will submit the Upper Pitt proposal into BC Hydro's next Clean Power Call, expected to be announced in the first half of 2010.

In terms of the 2009 Bioenergy Call for Power Phase II, BC Hydro had indicated initially that it would be issuing draft RFP documents in May 2009. On October 9, 2009, BC Hydro announced it was continuing to work to resolve key aspects of the Biomass Projects RFP. These include fuel risk sharing options, consideration and integration of new First Nations-related requirements, and refining the eligibility criteria to limit participation by customers who are eligible to receive funding under the Government of Canada's Pulp and Paper Green Transformation Program. When the Biomass Phase II RFP documents are issued, the Corporation will submit proposals for both of its Biomass projects.

PROJECT UPDATES

Mamquam Cluster Run-of-River Project (Advanced Development)

Mamquam Power Cluster (47 MW)		
	Capacity (MW)	Estimated Energy GWh/yr
Skookum Creek	25	98
Crawford Creek	7	28
Raffuse Creek	10	40
Mamquam Headwaters	5	19

The Mamquam project is approximately 70 km north of Vancouver. The cluster will connect to BC Hydro's grid at the Cheekye Substation, just north of Squamish, BC. This cluster of run-of-river power projects will have a combined capacity of 47 MW and will generate an estimated 185 GWh/yr of green electricity. A Feasibility Interconnection Study Agreement for connection to the grid was submitted to the British Columbia Transmission Corporation (BCTC) on November 17, 2008. On November 25, 2008, the Corporation submitted a proposal for Skookum Creek (25 MW) into BC Hydro's Clean Call for Power. The remaining creeks with a combined capacity of 22 MW may be advanced at a later date into BC Hydro's Standing Offer Program. On November 17, 2009 BC Hydro notified the Corporation that the 25 MW Mamquam proposal would be proceeding to the next stage of the 2008 Clean Power Call, aimed at securing an EPA in the near term.

Upper Pitt Cluster (Advanced Development)

Upper Pitt Cluster (155 MW)		
	Capacity (MW)	Estimated Energy GWh/yr
Bucklin Creek	30	108
Pinecone Creek	25	90
Shale Creek	15	54
Steve Creek	15	51
Corbold Creek	20	84
East Corbold Creek	15	69
Homer Creek	10	44
Boise Creek	25	92

The Upper Pitt project is in close proximity to the Mamquam watershed. It will also connect to BC Hydro's grid at the Cheekye Substation.

The Corporation and its wholly owned subsidiary, NWCP, have been exploring the development of run-of-river power projects in the Fraser Valley Regional District since the successful development of the Brandywine Creek project in 2005. The cluster includes seven run-of-river power projects on eight tributaries of the Upper Pitt River, located North of Pitt Lake, approximately 40 km east of Vancouver, BC and 45 km north of Pitt Meadows, BC.

NWCP proposed a 138 kV, 42 kilometre transmission line (Upper Pitt – Mamquam transmission line) to transmit renewable energy from the Upper Pitt and Mamquam projects to BC Hydro's Cheekye substation. Optimized hydrology studies support a combined plant capacity of 155 MW for the Upper Pitt Cluster and an estimated 592 GWh/yr of green electricity generation. These sites were chosen not only for the suitability of high-elevation creeks for run-of-river green power, but also for the proximity to the major population of the

Lower Mainland, where so much of BC's new residential and commercial growth has increased the demand for electricity.

NWCP submitted an application for a park boundary adjustment to BC Parks (Ministry of Environment) in respect of its Upper Pitt Project. A park boundary adjustment would be required to allow for 4.3 kilometres of transmission line to cross a remote mountain pass in Pinecone Burke Provincial Park. In March 2008, the BC Environment Minister advised he would not recommend to Cabinet or the BC Legislature acceptance of a park boundary adjustment for Pinecone Burke Provincial Park.

The Katzie First Nation, which has a co-management agreement for Pinecone Burke Provincial Park, has initiated a Supreme Court civil suit against the BC Ministry of Environment regarding the Minister's decision. The civil suit claims a breach of obligations to comply with the terms of a 1995 cooperative management agreement between the parties for the park.

Subsequent to the Minister's announcement regarding the Corporation's application for a park boundary adjustment and his advice to the Corporation to consider other transmission route options for the project, the Corporation initiated discussions with the BC Ministry of Environment in relation to a "park use permit" for the purposes of constructing a 4.3 km transmission link under Pinecone Burke Provincial Park. This route option addresses concerns brought forward by the public and stakeholders during the "park boundary adjustment" process. The Corporation intends to pursue a park use permit concurrently with the environmental assessment review of the project.

A Feasibility Interconnection Study Agreement for connection to the grid was submitted to the British Columbia Transmission Corporation (BCTC) on November 17, 2008, for the Upper Pitt – Mamquam transmission line, in connection with the Upper Pitt Project.

ROR Power's Upper Pitt – Mamquam transmission line will be a joint venture with its First Nation partners. The Corporation signed a Benefit and Support Agreement with the Katzie First Nation and recently signed a Memorandum of Understanding with the Squamish First Nation with respect to this shared transmission line.

On November 17, 2009 BC Hydro notified the Corporation that uncertainty related to the transmission route posed sufficient risk to the project such that the Upper Pitt proposal would not be proceeding to the next stage of the 2008 Clean Power Call. The Corporation intends to solve the transmission routing and will submit the Upper Pitt proposal into BC Hydro's next Clean Power Call, expected to be announced in the first half of 2010.

Future Development Prospects

Throughout 2008, the Corporation advanced 27 new run-of-river power projects in central British Columbia. Water License and Crown Land applications have been submitted to the Integrated Land Management Bureau (Ministry of Agriculture and Lands) and the Water Stewardship Division (Ministry of the Environment), and ROR has commenced further analysis on these projects.

The projects are located in the upper Klinaklini and Mosley watersheds, and in the area west of Williams Lake on the Chilcotin Plateau of central British Columbia, stretching to Bella Coola.

The Klinaklini power cluster has a capacity estimated at 117 MW. The Mosley power cluster has a capacity estimated at 96 MW, and the Bella Coola Cluster has a capacity estimated at 224 MW. The combined total output for these projects is estimated to be 1500 GWh of green energy per year, enough power to meet the energy needs of approximately 150,000 homes.

Seasonality of Run-of-River Production

Production of electricity from run-of-river developments is highly dependent on weather conditions, and can vary significantly; thus, it is not necessarily meaningful to compare monthly production results. The use of month-to-month and year-to-year analysis rather than long-term averages provides a guide only; for example, a wet or dry month can vary significantly from that month's long-term average. A generally cooler spring would be expected to result in a slower ice pack melt and extend utilizable water volumes later into the summer. The feasibility of the Corporation's run-of-river projects is based upon long-term averages. Production by fiscal quarter based on these long-term averages is expected, over the longer term, to approximate:

Q1 – 10% Q2 – 34% Q3 – 36% Q4 – 20%

Biomass Projects

Run of River Power Inc.'s advanced development pipeline consists of the following biomass projects:

Biomass (94 MW)		
	Capacity (MW)	Estimated Energy GWh/yr
Tsilhqot'in Power Project (Western Biomass)	60	420
Suskwa Power Project (PNBC)	34	252

The Corporation currently has two large scale biomass power initiatives totalling 94 MW of base load capacity under development. The 60 MW Tsilhqot'in Power Project, located 75 km west of Williams Lake in Hanceville, BC is a joint venture between the Corporation's wholly owned subsidiary, Western Biomass, and the Tsilhqot'in National Government ("TNG"). It will utilize mountain pine beetle damaged timber, which has devastated over 8 million hectares of pine forests in central British Columbia, unlogged roadside debris and sawmill waste for its fuel supply.

The second project is the 34 MW Suskwa Power Project, to be located in Northwest BC near New Hazelton. The Corporation, via Western Biomass, purchased 80% of PNBC whereby PNBC holds a 100% interest in the project with an option for its partners, the Suskwa Chiefs, to acquire up to 40% of the facility. The plant is strategically located less than four kilometres from the provincial transmission grid and will draw from what has been described as one of the best fibre baskets in the province, primarily utilizing decadent (dead) standing timber as well as biomass waste from existing logging operations in the area, for its fuel supply.

In June 2008, Tsilhqot'in Power Corp. (Western Biomass and the TNG) completed a detailed engineering study and fuel supply analysis for the 60 MW Tsilhqot'in Power Project. The Corporation, through PNBC, completed a similar fuel supply analysis for the 34 MW Suskwa Power Project. Western Biomass, together with the TNG and the Suskwa Chiefs Economic Corp. ("Suskwa"), submitted proposals to BC Hydro for the two projects referred to above, in response to Phase I of its two-phase Bioenergy Call for Power, to supply energy generated from forest-based biomass. Applications were also filed with BC Transmission Corporation for feasibility interconnection studies related to the two projects. BC Hydro awarded four EPA's under Phase I, primarily to forest companies with existing fibre tenures and partial infrastructure in place.

Western Biomass will resubmit the Tsilhqot'in Power Project and the Suskwa Power Project into BC Hydro's Bioenergy Call Phase II. Although no definitive timelines have been provided by BC Hydro, the Phase II process is expected to conclude with a selection of projects for EPA's in mid-2010.

SELECTED FINANCIAL INFORMATION ¹

(\$000's except per share and generation amounts)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
Electricity sales	434	664	1,097	1,250
EBITDA	(73)	58	(476)	(627)
Net loss	(418)	(278)	(1,481)	(1,510)
Basic and diluted loss per share	(0.01)	(0.00)	(0.02)	(0.02)
Cash flow used in operations	(224)	(60)	(908)	(795)
Total assets	31,485	32,422	31,485	32,422
Total long-term financial liabilities (incl current portion)	11,250	11,542	11,250	11,542
Generation-MWh	7,464	11,484	18,853	21,615

(1) Selected financial information was derived from the unaudited consolidated financial statements for the most recent quarters with certain comparative figures reclassified to conform with the financial presentation adopted for the present year and is prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). EBITDA is provided to assist management and investors in determining the Corporation's cash flow provided by operations before interest and does not have any meaning prescribed in Canadian GAAP and may not be comparable to similar measures presented by other companies. Refer to Non-GAAP measure - EBITDA below for the reconciliation between this non-GAAP financial measure and comparable measures calculated in accordance with Canadian GAAP.

Non-GAAP measure - EBITDA

(\$000's)	Three Months Ended September 30		Nine Months Ended September 30	
	2009	2008	2009	2008
GAAP Measures in Consolidated Statements of Operations				
Net loss for the period	(418)	(278)	(1,481)	(1,509)
Net interest	178	177	507	398
Depreciation and amortization	167	159	498	484
Non-GAAP measure – EBITDA	(73)	58	(476)	(627)

RESULTS OF OPERATIONS

Revenues

Q3 2009 electricity sales of \$434,211 decreased \$229,957 or 35% from Q3 2008 sales of \$664,168 as a direct result of a decrease in electricity generated to 7,464 MWh from 11,484 MWh. YTD electricity generation decreased 13% to 18,853 MWh from 21,162 MWh. YTD electricity sales decreased 12% to \$1,096,691 from \$1,250,096. The decrease in electricity generation and sales is attributable to decreased production at the Brandywine Creek facility, predominantly due to less than expected precipitation during the quarter. A five-day unscheduled outage to remove silt from the head pond occurred in late September.

Plant operating expense

Q3 2009 plant operating expense was \$149,514 or \$15,909 lower than the same period in 2008. Similarly, 2009 YTD operating expense was \$435,734 or \$49,684 lower than the same period in 2008. This reduction of 10% resulted from a repair that occurred in Q3 2008.

Depreciation and Amortization

Depreciation expense increased to \$161,444 during the third quarter of 2009, compared to \$153,967 for the same quarter of 2008. This slight increase of \$7,477 or 5% was due to the capitalization and depreciation of additional assets at the Corporation's head office during 2009. Similarly, 2009 YTD depreciation expense was \$481,819 compared to \$468,041 for the same period in 2008.

General and administration

General and administration ("G&A") expense of \$354,000 during the third quarter of 2009 was \$79,695 or 18% lower than G&A expense of \$433,695 during the third quarter of 2008. YTD general and administration costs of \$1,126,152 were \$253,317 lower than the same period in 2008. The lower YTD G&A costs were attributable to lower legal expenditures and stock-based compensation compared to the same period last year, primarily in Q1 2008.

Interest expense

The Corporation incurred net interest expense of \$177,720 during the third quarter of 2009, compared to \$176,711 for the same quarter of 2008. YTD net interest expense was \$507,388 compared to 398,103. The variance in both Q3 and YTD numbers was the result of significant interest income earned in 2008 on the proceeds of the 2007 equity issue invested in interest bearing marketable securities.

Net loss and funds used in operations

The Corporation recorded a net loss for the third quarter of 2009 of \$418,079 compared to a net loss of \$277,719 for the same period in 2008. YTD 2009 loss of \$1,481,315 was substantially unchanged from the same period in 2008 at \$1,509,920. Funds used in operations were \$224,095 for the third quarter of 2009 compared to \$60,013 for the same period of 2008 as a direct result of lower production and revenue from the Brandywine facility.

Risks and Uncertainties

According to the Independent Power Producers Association for British Columbia, a run-of-river project in BC requires over 50 permits, licences, and approvals and reviews from 14 different government agencies before it can be built. Such a regulatory environment creates additional challenges and may result in unanticipated delays or material alterations in project outcomes, including cancellation. There is no guarantee that all projects within the Corporation's development portfolio will come to fruition.

SELECTED QUARTERLY FINANCIAL INFORMATION

Financial Quarter Ended (Unaudited)

(in thousands of Canadian dollars except loss per share amounts)	2009			2008				2007
	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31
Revenues	434	577	86	431	664	477	109	563
Net loss	(418)	(317)	(746)	(511)	(278)	(464)	(768)	(644)
Basic and diluted loss per share	(0.01)	(0.00)	(0.01)	(0.01)	(0.00)	(0.01)	(0.01)	(0.01)

Production of electricity is highly dependent on weather conditions and can vary significantly resulting in significant variability in quarterly operating results as more fully explained on Page 7 under "Seasonality of Operations".

LIQUIDITY AND CAPITAL RESOURCES

Liquidity

At September 30, 2009, the Corporation had \$1.4 million in cash on hand. These cash resources will be used to advance the Corporation's portfolio of development projects. Final regulatory approval of any of the facilities in development will require additional funds that will exceed the current resources of the Corporation. Additional financing in some form will be required. The completion of any of the projects in development is also expected to have a material impact on the Corporation's future operational results and cash flows. The Corporation currently foresees no impediments to its ability to meet its ongoing requirements and its development activities.

Commitments of capital expenditures will be wholly dependent on the successful completion of proposed projects. The success of these projects is dependent upon receiving the necessary water and other licences, the ability of the Corporation to obtain necessary financing to successfully complete the development and construction of the projects, the ability to economically generate electrical power and its ability to sell the electricity generated on a profitable basis to BC Hydro under EPA's. No additional projects of the Corporation have, at this point, received final approval.

Capital resources

The capital structure of the Corporation consists of shareholders' equity, long-term debt and cash and cash equivalents as noted below:

	September 30, 2009	December 31, 2008
Components of Capital:		
Shareholders' equity	\$ 19,462,774	\$ 19,828,714
Long – term debt	11,249,889	11,542,485
Less:		
Cash and cash equivalents	(2,011,181)	(4,041,607)
Net Capital	\$ 28,701,482	\$ 27,329,592

The Corporation's objectives when managing capital are to:

- balance the interest of equity and debt holders;
- maintain compliance with its financial covenants; and
- maintain a capital base so as to maintain investor, creditor and market confidence and to sustain future development.

The Corporation manages its capital structure as determined by management and approved by the Board of Directors. The Corporation's policy is to make adjustments to its capital structure based on changes in economic conditions and planned requirements. The Corporation has the ability to adjust its capital structure by issuing new equity or debt, selling assets to reduce debt or balance equity, and making adjustments to its capital expenditures program.

The Corporation monitors capital using a Debt Service Coverage Ratio that has been externally imposed as part of the loan agreement. The Corporation is required to maintain a four quarters rolling average Debt Service Coverage Ratio not less than 1.00:1. This ratio is calculated as follows:

Q4 2008	1.03
Q1 2009	0.09
Q2 2009	1.71
Q3 2009	0.83
Four quarters rolling average – December 31, 2008	0.91
Four quarters rolling average – March 31, 2009	0.84
Four quarters rolling average – June 30, 2009	1.01
Four quarters rolling average – September 30, 2009	0.91

The Corporation was in compliance with the terms of its credit facilities during each of the first three quarters of 2008 and for the second quarter of 2009. At December 31, 2008, March 31, 2009, and September 30, 2009, the Debt Service Coverage Ratio was less than 1.00:1 due to reduced revenues caused by abnormally low water flow. Pursuant to the Loan Agreement, the Corporation has notified its lenders of this event of default and has received a waiver of this covenant.

There have been no changes to the Corporation's capital structure, objectives, policies and processes over the prior year.

RELATED PARTY TRANSACTIONS

At September 30, 2009, the Corporation was owed \$96,578 (December 31, 2008 - \$96,578) by Rockford Technology Corporation which has a director in common. The loan is unsecured and bears interest at 9%. The original loan due September 17, 2006 was extended under the same terms to December 17, 2009. At September 30, 2009, accrued interest totalled \$15,211.

During the period the Corporation incurred certain project costs related to its biomass projects totalling \$206,870 (2008 - \$145,470) which may be recoverable should the projects proceed to completion.

CRITICAL ACCOUNTING ESTIMATES

Measurement uncertainty

The preparation of the consolidated financial statements requires the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. These estimates will affect assets, liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements, as well as revenues and expenses during the reporting periods. Such estimates are based on informed judgments made by management. Actual results could differ from those estimated as future confirming events occur. Significant estimates used in the preparation of the financial statements include, but are not limited to, the estimates of asset retirement obligations, useful life and salvage values of property, plant and equipment, impairment of projects under development and income taxes.

The Corporation has adopted depreciation policies which are reflective of the estimated useful lives and abandonment costs, if any, of its assets. No amounts have been recorded in respect of abandonment as none of these assets have been identified at present. Hydroelectric assets tend to have long useful lives, often in excess of 50 years. Mechanical portions and assets such as transmission lines may require significant refurbishment from time to time in order to maintain their productive levels.

The Corporation capitalizes costs of developing its power generation projects. The recovery of those costs is dependent on the ability of the Corporation to obtain EPA's from BC Hydro and successfully construct the projects in an economic fashion. The Corporation believes that costs capitalized in respect of these projects are not impaired and no adjustment to carrying values is necessary at this time.

ADOPTION OF NEW ACCOUNTING STANDARDS

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Institute of Chartered Accountants confirmed that Canadian GAAP for publicly accountable enterprises will be converted to International Financial Reporting Standards (IFRS) on January 1, 2011. This change in GAAP will be effective for years beginning January 1, 2011 and will require the restatement for comparative purposes of amounts reported by the Corporation for the year ended December 31, 2010.

At this time, the Corporation has appointed internal staff to lead the conversion project along with sponsorship from the senior leadership team to manage this transition and to ensure successful implementation within the required time frame. The Corporation will provide disclosures of key elements of its plan and progress on the project as the information becomes available during the transition period. The Corporation is now assessing the impact of the conversion from Canadian GAAP to IFRS on its results of operations, financial position and disclosures, and is preparing a plan for implementation, including the preparation of required comparative information.

The key elements of the Corporation's implementation plan include:

- determining appropriate changes to accounting policies and financial disclosures;
- identifying and implementing changes to associated processes and information systems; and
- communicating changes and requirements to internal and external stakeholders.

The corporation is currently analyzing accounting policy alternatives and identifying implementation options for the corresponding process changes. In 2010, ROR expects to run parallel between Canadian GAAP and IFRS with a full IFRS implementation by January 1, 2011. Although Canadian GAAP and IFRS have certain similarities, significant differences exist which may have a high impact on the Corporation's reporting. These areas include, but are not limited to, property, plant and equipment, projects under development, impairment, business combinations, future income taxes and provisions. The Corporation will update its IFRS plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. The impact of IFRS on the Corporation's consolidated financial statements is not reasonably determinable at this time.

Business combinations, consolidated financial statements and non-controlling interests

In January 2009, the AcSB issued CICA Handbook Sections 1582 – Business Combinations, 1601 – Consolidated Financial Statements and Section 1602 – Non-controlling Interests. Section 1582 is effective for business combinations subsequent to January 1, 2011. This Standard was issued to align Canadian GAAP with IFRS. The Standard requires additional use of fair value measurements, recognition of additional assets and liabilities and increases disclosure. Adoption of this Standard will have a material effect on the method of accounting for business combinations in future periods. Upon adoption of Section 1582, entities are required to adopt Sections 1601 – Consolidated Financial Statements and 1602 – Non-controlling interest. These two standards require a change to be presented as part of shareholder's equity on the balance sheet. The income statement of the controlling parent will require all of the subsidiaries results and present an allocation between the controlling interest and the non-controlling interest. Adoption of Section 1582 is applied prospectively and Sections 1601 and 1602 are applied retroactively.

Goodwill and intangible assets

The CICA has issued Section 3064 – Goodwill and Intangible Assets to replace Section 3062 – Goodwill and Other Intangible Assets. Section 3064 gives guidance on the recognition of intangible assets as well as the recognition and measurement of development expenditures. Section 3064 – Goodwill and Intangible Assets is effective for annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. These changes are effective for the Corporation on January 1, 2009 and its implementation is not expected to have a material impact on the financial position or results of operations.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value of financial instruments

The fair value of financial instruments is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act. Fair values are determined by reference to quoted market prices, as appropriate, in the most advantageous market for that instrument to which the Corporation has immediate access. Where quoted market prices are not available, the Corporation uses the closing price of the most recent transaction for that instrument. In the absence of an active market, fair values are determined based on prevailing market rates for instruments with similar characteristics.

The Corporation designated cash, restricted cash and marketable securities as held-for-trading assets, measured at fair value. Amounts receivable are measured at amortized cost. Accounts payable and accrued liabilities and long-term debt are designated as other financial liabilities and measured at amortized cost. Management did not identify any material embedded derivatives, which require separate recognition and measurement under the new accounting standards. The Corporation had neither available-for-sale, nor held-to-maturity instruments during the period ended September 30, 2009.

Risk management

The Board of Directors has the overall responsibility for the establishment and oversight of the Corporation's risk management. Senior management is responsible for developing and monitoring compliance with the Board's risk management objectives. Derivative financial instruments are not used by the Corporation for speculative purposes.

In the normal course of operations, the Corporation is exposed to various risks such as commodity, interest rate, credit, liquidity, and operating risk. To manage these risks, management determines what activities must be undertaken to minimize potential exposure to risks. The objectives of the Corporation to managing risk are as follows:

- maintaining sound financial condition;
- financing operations; and
- ensuring liquidity to all operations.

In order to satisfy these objectives, the Corporation has adopted the following policies:

- prepare budget documents at prevailing market rates to ensure clear, corporate alignment to performance management and achievement of targets;
- recognize and observe the extent of operating risk within the business;
- identify the magnitude of the impact of market risk factors on the overall risk of the business and take advantage of natural risk reductions that arise from these relationships.

There have been no changes in risks that have arisen or how the Corporation manages those risks from the prior period.

Electricity commodity risk

The Corporation manages the risk of fluctuating commodity prices by entering into long-term, 20-year fixed price Electricity Purchase Agreements with B.C. Hydro for the sale of its production.

Interest rate risk

The Corporation's long term debt bears interest at fixed rates, thus mitigating the impact of fluctuations in interest rates.

Credit risk

Credit risk is the risk of loss if counterparties do not fulfil their contractual obligations and arises principally from trade receivables. The maximum exposure to credit risk is the carrying amount of amounts receivable principally from BC Hydro for the sale of production from the Corporation's Brandywine Creek facility. BC Hydro is a rated, creditworthy counterparty and amounts receivable are current as of September 30, 2009.

Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they come due. The Corporation mitigates this risk through actively managing its capital, which it defines as shareholders' equity, long term debt, net of cash, cash equivalents and marketable securities. Management of liquidity risk over the short and longer term includes continual monitoring of forecasted and actual cash flows to ensure sufficient liquidity to meet financial obligations when due and maintaining a flexible capital management structure. The Corporation strives to balance the proportion of debt and equity in its capital structure given its development assets and planned investment opportunities.

The current volatile economic and financial conditions have impacted the availability of financing for the Corporation's development initiatives. Furthermore, the associated terms have changed to reflect the increased risk. It is the Corporation's view that project financing will be available for the development projects included in the Corporation's bids in response to the BC Hydro calls, albeit under more stringent financing conditions. The credit quality of long-term Energy Purchase Agreements with BC Hydro, along with the nature of the Corporation's development projects, facilitates completion of financing in these circumstances.

The ability of the Brandywine Creek power plant to generate the maximum amount of power is a determinant of the Corporation's profitability. Regular preventative maintenance programs and insurance mitigate the risk of potential equipment failure and the consequent loss of revenue. The Corporation has no obligation under its contract to deliver minimum levels of power. Any reduction in the volume of power delivered will directly reduce the amount of power revenue received by the Corporation.

OUTSTANDING SHARE DATA

Total issued common shares at September 30, 2009	74,002,461
Total issued common shares at November 27, 2009	74,002,461
Outstanding warrants	2,950,000
Outstanding share options	6,070,000
Total fully diluted common shares at November 27, 2009	83,022,461

SUBSEQUENT EVENT

Subsequent to quarter end, an extraordinary outage at a BC Hydro substation led to the outage at the Company's Brandywine facility that resulted in damage to one of two generators. Although the generator is expected to be out of service for up to four months, the Company does not anticipate a significant impact on revenue as plant output is typically captured by one generator during the corresponding period. The Company's insurers are assessing the facility and repairs and business interruption are expected to be covered by insurance, subject to associated deductibles.