MANAGEMENT'S DISCUSSION AND ANALYSIS
DECEMBER 31, 2005

Attached is management's discussion and analysis of Brookfield Power Inc., formerly Brascan Power Inc.
Brookfield Power Inc. is a subsidiary of Brookfield Asset Management Inc., formerly Brascan Corporation.

MANAGEMENT'S DISCUSSION AND ANALYSIS

MARCH 3, 2006

INTRODUCTION

The information provided in this management discussion and analysis (MD&A) is intended to provide readers with an assessment of our performance for the past twelve months, the fourth quarter of 2005 and the comparable periods of last year, while also serving to give a framework for understanding our competitive advantages, the long-term growth trends of our business and the ability of our assets to deliver strong and stable cash flows. The MD&A should be read in conjunction with our audited consolidated financial statements. Additional information can also be found on our website at www.brookfieldpower.com and on the SEDAR website at www.sedar.com. The financial information contained herein is prepared in accordance with Canadian generally accepted accounting principles ("GAAP") unless otherwise indicated. If required by the context or unless otherwise indicated, the terms "the Company", "we," "our" and "us" refer to Brookfield Power Inc. (formerly known as Brascan Power Inc.) and all of its subsidiaries and joint ventures. The following MD&A is the responsibility of management and is prepared in accordance with the requirements of national instrument 51-102 of the Ontario Securities Commission.

Effective January 1, 2005, our functional and reporting currency changed from the Canadian ("CDN") dollar to the United States ("US") dollar as a result of the increase in US dollar denominated activity in the operations as compared to prior years. For additional information on the impact of the change in functional currency, please refer to note 3 of the December 31, 2005 consolidated financial statements. Unless expressly indicated otherwise, all amounts are reflected in US dollars.

On January 1, 2005, we adopted the revisions to CICA Handbook Section 3860, Financial Instruments – Disclosure and Presentation on the classification of financial instruments as debt or equity, with retroactive restatement of prior periods. The new rules require that capital securities that are convertible into a variable number of common shares and interest payments on the capital securities that can be paid by way of a variable number of common shares, be classified as liabilities. We reclassified a portion of capital securities to liabilities and included it in debt portion of capital securities due to the fact that the interest may be paid in a variable number of common shares at our option. For the year ended December 31, 2004, the corresponding interest expense on the capital securities has been reclassified from shareholders' equity to interest expense on the consolidated statement of income, with the remainder recognized through retained earnings.

On January 1, 2005, we adopted Accounting Guideline 15, Consolidation of Variable Interest Entities ("AcG 15"), issued by the Canadian Institute of Chartered Accountants ("CICA"). AcG 15 provides guidance for applying the principles in handbook section 1590, "Subsidiaries," to those entities (defined as Variable Interest Entities ("VIE")), in which either the equity at risk is not sufficient to permit that entity to finance its activities without additional subordinated financial support from other parties, or equity investors lack voting control, an obligation to absorb expected losses, or the right to share expected residual returns. AcG 15 requires consolidation of VIEs by the primary beneficiary, which is defined as the party which has exposure to the majority of a VIEs expected losses and/or expected residual returns. As a result of the adoption of this new standard, Great Lakes Hydro Income Fund (the "Fund"), of which we own a 50.1% interest, is now fully consolidating its proportionate joint venture interests in Powell River Energy Inc. ("PREI") and Powell River Energy Partnership ("PREP"), versus the 50% proportionate consolidation method previously used. We are also fully consolidating our 75% residual interest in Catalyst Old River Hydroelectric Limited Partnership ("CORHLP"), also referred to as Louisiana HydroElectric Power ("LAH"), versus the equity accounting method previously used.

OVERVIEW OF THE BUSINESS

As at December 31, 2005, we own and operate 119 hydroelectric power generating stations throughout North America, located on 35 river systems and 2 co-generation plants with an installed capacity of 3,189 MW, capable of generating approximately 11,000 GWh of electricity annually.

Our power generating operations are located in the regionally interconnected markets of Ontario, Quebec, New England and New York, as well as British Columbia and Louisiana. We also own a regulated transmission and distribution business in Ontario. The transmission and distribution business consists of 17 transmission stations and 14 distribution stations servicing approximately 11,500 customers. Some of our assets are owned through the Fund, a publicly traded reporting issuer on the Toronto Stock Exchange (symbol: GLH.UN). The Company also operates 12 hydroelectric power generating stations owned indirectly by Brookfield Asset Management Inc. ("Brookfield"), formerly known as Brascan Corporation. The Company, which has an investment in preferred shares in these facilities, manages the operations. These stations are located on 9 river systems in Brazil, have an installed capacity of 205 MW and can generate, on an annual basis, in excess of 900 GWh of electricity.

We are a wholly owned subsidiary of Brookfield, an asset manager. Focused on property, power and infrastructure assets, Brookfield has approximately US $50 billion of assets under management and is co-listed on the Toronto and New York Stock Exchanges under the symbol BAM.

OPERATING STRATEGY AND OUTLOOK

We are committed to expanding our power generation base by strategically acquiring existing hydroelectric assets and developing renewable energy projects such as small hydroelectric facilities and wind farms. Furthermore, we are committed to reinvesting in our regulated transmission and distribution system in Ontario. During the year, we increased generating capacity by 681 megawatts through the acquisition of the Hydro Kennebec, West Delaware, Piney, Deep Creek and Bear Swamp facilities. Our acquisitions in the past few years have allowed us to establish a geographic presence in several regions, including the regionally interconnected markets of Ontario, Quebec, New England and New York. We will continue to identify new opportunities to optimize the performance of our portfolio and expand and continue our diversification strategy in 2006 and beyond.

We are focused on delivering long-term sustainable cash flows through the operation of low-cost hydroelectric power generating facilities. We strive to maximize the stability and predictability of power generating revenues through the use of fixed price contracts and a managed hedging strategy, which serve to minimize the impact of price fluctuations, and through diversification of watersheds and water storage reservoirs to manage fluctuations in generation levels.

We will continue to preserve and enhance the value and reliability of our operations through capital additions and major maintenance work. In 2006, we expect to invest more than $424 million to that effect. The completion of the Northern Ontario wind power project ($279 million), the reinforcement of the transmission system ($11 million), the Shikwamkwa dam repairs ($14 million) and the refurbishment of the High Falls generating station of the Lièvre Power System ($14 million) are estimated to account for approximately $318 million of the total 2006 capital program spending.

Overall, we are optimistic with respect to our 2006 outlook on operations. As at December 31, 2005, the majority of our reservoirs had returned to their expected seasonal levels. As such, long-term average continues to be the best estimate for anticipated generation in 2006. Although prices have somewhat declined from the peak in 2005, they still remain strong. As a result, we expect net operating income during 2006 to exceed 2005 assuming the current pricing environment remains high and water inflows stay consistent with long-term average.

We continue to manage the business in a way that will optimize cash flows and create value. We are confident that we should realize our 2006 performance objectives.

PERFORMANCE MEASUREMENT

We focus principally on net operating income for performance measurement since it is a tangible measurement and best reflects the value of our assets. We define net operating income as revenues from our power operations, net of operating and maintenance costs, fuel purchases for the co-generation plants, power purchases, selling, marketing and administration expenses and municipal and other generation taxes on our facilities. Interest and financing fees, interest on capital securities, depreciation and amortization, provision for income taxes and non-controlling interest are deducted from net operating income to obtain net income. Refer to the Net Income Analysis section for a reconciliation of net operating income to net income. Net operating income is a non-GAAP measure and may differ from definitions of net operating income used by other companies.

PERFORMANCE OVERVIEW

Our 2005 financial results were the strongest in the history of our company. Net operating income increased to $463 million in 2005, compared with $365 million in 2004. Our New York operations, acquired in September 2004, contributed $140 million to our net operating income in 2005, compared to $18 million for the three month period of 2004. The continued increase in fossil fuel prices has led to an increase in power prices in Ontario, New York and New England, as the electricity prices in those regions are set by natural gas. This positively impacted our net operating income, as our cost of generation for hydroelectric facilities was not affected by the increase in fuel costs. Lower than average hydrology conditions, mostly in Louisiana and Ontario, negatively impacted net operating income in 2005.

Overall, generation from assets owned at December 31, 2005, before the impact of 2004 and 2005 acquisitions, totalled 6,611 GWh for the year, 10% below our long-term average and 12% below 2004, mostly resulting from below average water inflows in our Ontario, Quebec and Louisiana power systems. Our New England and New York operations partly offset this shortfall and generated more than their long-term average in 2005, demonstrating the benefits of our diversification strategy.

GENERATION	Twelve months ended December 31		
Gigawatt hours	**2005**	2004[1]	Long-term average[2]
Assets owned at December 31, 2003			
Ontario	**1,766**	2,311	2,412
Quebec	**1,475**	1,661	1,639
British Columbia	**560**	568	523
New England	**1,124**	952	1,010
Louisiana	**813**	1,099	903
Gas co-generation	**873**	880	850
Total assets owned as of December 31, 2003	**6,611**	7,471	7,337
Acquisitions – 2004	**3,224**	894	3,028
Acquisitions – 2005	**426**	-	418
	10,261	8,365	10,783

(1) 2004 comparative generation has been restated to reflect the adoption of Accounting Guideline 15, Consolidation of Variable Interest Entities.
(2) Adjusted long-term average for date of acquisition of the facilities.

Results for the past two years are summarized as follows:

US $ millions (except generation)	**2005**	2004[1]
Power generated (GWh)	**10,261**	8,365
Power revenues	**774**	667
Net operating income	**463**	365
Power generating assets and other assets	**3,891**	3,611
Total assets	**5,368**	5,136

(1) All 2004 comparatives have been restated to reflect the adoption of revisions to Section 3860, Financial Instruments- Disclosure and Presentation and Accounting Guideline 15, Consolidation of Variable Interest Entities.

Financial results for the year ended December 31, 2005 compared to 2004 are shown by business segment in the following table:

US $ millions	**2005**			2004[1]		
	GWh	**Revenue**	**Net operating income**	GWh	Revenue	Net operating income
Hydroelectric generation						
Ontario	**1,766**	**$ 114**	**$ 92**	2,311	$ 123	$ 101
Quebec	**1,475**	**76**	**64**	1,661	70	57
British Columbia	**659**	**21**	**15**	671	19	15
New England	**1,274**	**65**	**47**	1,056	49	34
New York	**3,089**	**196**	**140**	687	38	18
Louisiana	**813**	**133**	**112**	1,099	159	135
Sub-total	**9,076**	**605**	**470**	7,485	458	360
Gas co-generation	**926**	**66**	**21**	880	53	21
Transmission and Distribution	**n/a**	**35**	**24**	n/a	29	18
Other	**259**	**68**	**(52)**	-	127	(34)
TOTAL	**10,261**	**$ 774**	**$ 463**	8,365	$ 667	$ 365
Hydroelectric revenue/ MWh (in $)		**$ 66.66**			$ 61.19	

(1) All 2004 comparatives have been restated to reflect the adoption of revisions to Section 3860, Financial Instruments- Disclosure and Presentation and Accounting Guideline 15, Consolidation of Variable Interest Entities.

During 2005, power prices continued to increase in most of the regions in which we operate. Consistent with our strategy to mitigate the impact of price volatility on our power generating revenues, a significant portion of our generation was hedged and, as a result, prevented us from capturing all of the benefit of these higher market prices.

ONTARIO

Revenue from Ontario operations decreased by 7% or $9 million from the prior year, due to a significant decrease in power generation of 545 GWh from 2004. Our dispatching strategy, which consists of maximizing generation in periods when power is in higher demand, the favourable impact of the Canadian dollar exchange rate and the impact of higher prices on non-hedged generation, partially offset the effect of below average water inflows in Ontario. Despite a stronger Canadian dollar, lower generation resulted in stable operating costs when compared to 2004. The combination of lower revenue and comparable operating costs resulted in a decrease in net operating income of $9 million.

QUEBEC

Revenue from our operations in Quebec totalled $76 million during the year, representing an increase of 9% from 2004, despite lower generation. The favourable impact of the Canadian dollar exchange rate, an effective optimization of contracts and dispatch strategy, combined with an overall increase in the average selling price, offset the decrease in generation from 1,661 GWh in 2004 to 1,475 GWh in 2005. Lower operating costs resulting from lower generation were offset by the higher Canadian dollar exchange rate.

BRITISH COLUMBIA

Generation in British Columbia totalled 659 GWh in 2005, which is 2% below the 671 GWh generated in 2004. Revenue from our British Columbia operations totalled $21 million in 2005, representing an increase of 11% over 2004, primarily as a result of a stronger Canadian dollar. Costs increased by $2 million due primarily to higher major maintenance costs, increased property taxes and the stronger Canadian dollar.

NEW ENGLAND

Power generated by our operations in New England increased by 21% to 1,274 GWh in 2005, from 1,056 GWh in 2004. The increase in generation is partly attributable to the Hydro Kennebec and Fife Brook facilities acquired in 2005, which generated 103 GWh and $10 million in revenue. The remaining increase is the result of higher generation from existing facilities and higher market prices in 2005, compared to 2004, on non-hedged volume. In total, our New England operations contributed $65 million to our revenue in 2005 compared to $49 million in 2004. Overall, our New England operations generated $47 million of net operating income in 2005, an increase of 38% over 2004.

NEW YORK

Power generated by our operations in New York increased to 3,089 GWh in 2005, from 687 GWh in 2004. The full year contribution of the 71 hydroelectric power generating plants acquired in September 2004, combined with higher market prices, contributed $191 million to our revenues in 2005 versus $38 million in 2004. Furthermore, the 2005 acquisitions of the West Delaware, Piney and Deep Creek facilities contributed an additional $5 million in revenues. Operating costs for the region have increased by $36 million over the prior year, reflecting a full year of operation. Overall, New York's contribution of $140 million of net operating income makes it our most significant region and provides substantial geographic diversification to our watersheds.

LOUISIANA

Generation in Louisiana totalled 813 GWh in 2005, which is 26% below the 1,099 GWh generated in 2004 and 10% below the long-term average. This is the result of lower than normal hydrology conditions observed in 2005. Lower generation resulted in a decrease of $26 million in revenues, from $159 million in 2004, to $133 million in 2005. The impact of lower generation was partly offset by an increase in the average selling price. Costs have decreased by $3 million compared to 2004, which is relatively consistent in terms of percentage variation with the decrease in revenues. As a result, net operating income decreased by $23 million compared to 2004.

CO-GENERATION

Co-generation includes a 110 megawatt facility located in Ontario and a 105 megawatt facility located in New York. The twelve months of operation of the New York facility acquired in 2004 contributed an additional 52 GWh in 2005, for a total of 926 GWh in 2005 for these facilities, representing a 5% increase over the 880 GWh generated in 2004. The favourable impact of the Canadian dollar exchange rate on the Ontario facility and the incremental profit from gas remarketing resulting from higher gas prices at the end of the year resulted in a stable net operating income for the year.

TRANSMISSION AND DISTRIBUTION

Revenue from the transmission and distribution business contributed $35 million to the Company's 2005 revenues, an increase of $6 million from last year. This increase is due to the higher rate base approved by the Ontario Energy Board in 2005 to strengthen our Northern Ontario transmission systems. These higher revenues, combined with stable operating costs, resulted in an increase in net operating income from this segment of 33% over 2004.

OTHER

Other includes the New England pump storage facility, arbitrage revenues, power sales to an affiliate and other administration costs. The pump storage facility, acquired in 2005, contributed 259 GWh of generation, $21 million of revenue and $3 million in net operating income. The Company sold power to an affiliate, pursuant to a contract that expired in May 2005. Revenues earned from the sales of power to this affiliate amounted to $49 million in 2005, compared to $119 million in 2004. Corresponding costs amounted to $67 million in 2005, compared to $137 million in 2004.

NET INCOME ANALYSIS

Net income for 2005 totalled $60 million, compared to $76 million for last year. Despite higher net operating income for the year, lower net income in 2005, as compared to 2004, is primarily the result of interest on capital securities increasing to $120 million from $43 million in 2004. This increase is a result of an additional $909 million of capital securities that were issued in September 2004 to Brookfield, as a result of a special dividend paid and additional capital invested to support our New York acquisition.

US $ millions	2005	2004(1)
Net operating income	**$ 463**	$ 365
Investment income and other	**48**	68
	511	433
Interest and financing fees	**228**	176
Depreciation and amortization	**102**	74
Non-controlling interests	**16**	31
(Recovery of) provision for income taxes	**(15)**	33
Net income before interest on capital securities	**180**	119
Interest on capital securities	**120**	43
Net income	**$ 60**	$ 76

(1) All 2004 comparatives have been restated to reflect the adoption of revisions to Section 3860, Financial Instruments- Disclosure and Presentation and Accounting Guideline 15, Consolidation of Variable Interest Entities.

INVESTMENT INCOME AND OTHER

Investment and other income in 2005 decreased by $20 million relative to 2004, to a total of $48 million. Investment and other income consists of dividend income from long-term investments and the Company's securities portfolio, interest on cash and cash equivalents, swap recouponing income and gains and losses on foreign exchange. The decrease from 2004 is primarily due to less income received from investments which were sold to Brookfield on July 1, 2005.

INTEREST AND FINANCING FEES

US $ MILLIONS	Twelve months ended December 31	
	2005	2004(1)
Ontario	**$ 32**	$ 28
Quebec	**21**	11
British Columbia	**8**	7
New England	**8**	8
New York	**33**	6
Louisiana	**95**	86
Transmission and Distribution	**8**	4
Other businesses	**23**	26
Total	**$ 228**	$ 176

(1) 2004 comparative interest and financing fees have been restated to reflect the adoption of Accounting Guideline 15, Consolidation of Variable Interest Entities.

Interest and financing fees increased by $52 million from the prior year. The full year impact of interest on the $500 million bridge financing obtained to acquire the New York assets in late September of 2004, resulted in a $27 million increase when compared to the prior year. A yield maintenance payment of CDN $10 million, which was made as a result of the early redemption of the CDN $100 million Great Lakes Power Trust ("GLPT") first mortgage bonds on April 27, 2005, also impacted our interest and financing fees in 2005. The early redemption allowed us to secure long-term financing at very attractive rates. The CDN $77 million senior secured bonds issued in September 2004, secured by our co-generation facility in Ontario, increased our interest and financing fees by an additional $4 million. The increase in interest and financing fees of $9 million in Louisiana is related to interest payable on a note due to an affiliate of Brookfield Power.

DEPRECIATION AND AMORTIZATION

US $ MILLIONS	Twelve months ended December 31	
	2005	2004[(1)]
Ontario	**$ 14**	$ 15
Quebec	**8**	7
British Columbia	**3**	3
New England	**12**	8
New York	**24**	6
Louisiana	**19**	14
Transmission and Distribution	**8**	10
Other businesses	**14**	11
Total	**$ 102**	$ 74

(1) 2004 comparative depreciation and amortization have been restated to reflect the adoption of Accounting Guideline 15, Consolidation of Variable Interest Entities.

Depreciation and amortization in 2005 totalled $102 million compared to $74 million in 2004. The increase of $28 million is primarily attributed to additional depreciation on the New York assets acquired in the third quarter of 2004, as well as depreciation of other power generating facilities acquired in 2005.

NON-CONTROLLING INTERESTS

Non-controlling interests relate to income associated with the non-controlling interests in our consolidated entities. The decrease of $15 million in 2005 compared to the prior year is primarily due to lower net income from the Fund and the Louisiana operations. The portion of the Fund's net income attributed to the non-controlling interest is $11 million in 2005, compared to $19 million in 2004, as a result of lower water inflows in Ontario and Quebec. The portion of Louisiana's net income is $3 million in 2005 compared to $10 million last year, also as a result of lower water inflows on the Mississippi River.

PROVISION FOR INCOME TAXES

Provision for income taxes resulted in a $15 million recovery for 2005, compared to a $33 million expense in 2004. This primarily resulted from the impact of a reduction in the statutory corporate income tax rate to 34%, from 36% in 2004, a reduction in net income before tax due to additional interest on capital securities, and from a provision for a potential tax reassessment that was accounted for in 2004. A full reconciliation between the statutory tax rate and the effective tax rate is presented in the notes to the annual consolidated financial statements.

INTEREST ON CAPITAL SECURITIES

Following the retroactive adoption of CICA Handbook Section 3860, a large portion of the interest on the subordinated convertible debentures, which we refer to as capital securities, is recorded through the consolidated statement of income. Interest on the capital securities totalled $120 million in 2005, compared to $43 million in 2004. This increase is the result of recording a full year of interest on $909 million of capital securities which were issued to Brookfield during the third quarter of 2004.

BALANCE SHEET ANALYSIS

SHORT-TERM AND LONG-TERM INVESTMENTS

Short-term and long-term investments decreased by $712 million to $407 million as at December 31, 2005 (December 31, 2004 - $1,119 million) primarily due to dispositions. Demand deposits held with affiliates decreased by $289 million to $112 million as at December 31, 2005, which is a result of the timing of cash flow requirements. The Company increased its investment in preferred shares of Brascan Brazil Limited by $75 million during the second quarter of 2005.

POWER GENERATING ASSETS

Power generating assets as of December 31, 2005 totalled $2,997 million compared to $2,765 million as of December 31, 2004, an increase of $232 million.

US $ MILLIONS	
Power Generating Assets – 2004	**$ 2,765**
Acquisitions of power generating assets	**113**
Additions to existing power generating assets	**224**
Disposals	**(51)**
Depreciation	**(79)**
Other	**25**
Power Generating Assets – 2005	**$ 2,997**

This increase is partially attributable to the acquisitions of West Delaware, Hydro Kennebec, Bear Swamp, Piney and Deep Creek facilities, the construction of our first wind farm in Northern Ontario and our Cedar Dam project on the Lièvre River in Quebec. We also continued to progress on our transmission reinforcement project in Ontario by investing an additional $31 million in our regulated assets. In line with the Company's 20 year sustainable capital investment plan, we also continued to invest in several capital projects during 2005 to preserve and enhance the reliability of our operations. Significant capital projects during 2005 included the Shikwamkwa dam rebuild and the Weldon conversion project in Maine. The strengthening of the Canadian dollar further contributed to the increase of our power generating assets. These additions were offset by the sale of the White Mountain energy co-generator in the second quarter and of the Company's coal properties during the fourth quarter of 2005 and by the depreciation for the year.

OTHER ASSETS

Other assets as of December 31, 2005 totalled $894 million compared to $846 million as of December 31, 2004, an increase of $48 million.

US $ millions	Net book value as at December 31	
	2005	2004
Power purchase agreements	**$ 161**	$ 155
FERC licences	**38**	39
Deferred financing fees	**47**	41
Accrued levelized revenues	**543**	535
Commodity derivatives	**33**	-
Cash held in escrow	**56**	76
Other	**16**	-
	$ 894	$ 846

In 2005, an amount of $15 million of the acquisition price of Hydro Kennebec was allocated to the new power purchase agreements. Amortization of the power purchase agreements totalled $9 million ($1 million in 2004).

In 2005, the Company incurred $18 million of financing fees (2004 – $12 million) which have been deferred and are being amortized over the term of the underlying debt. Amortization totalled $8 million (2004 – $5 million).

Catalyst Old River Hydroelectric Limited Partnership ("CORHLP") sells power at predetermined fixed rates. These rates increase and decrease over the term of the power sales contract, which expires December 31, 2031. Power sales are recognized on a levelized basis over the term of the contract. The difference between levelized power sales and cash received is recorded as accrued levelized revenue on the balance sheet.

Commodity derivatives are explained in more detail in the Derivative Financial Instruments section of the MD&A.

Cash held in escrow is composed of $21 million related to the new financing in New York for a debt service reserve (2004 - $nil) and $35 million related to CORHLP (2004 - $76 million). The decrease in the CORHLP balance is due to the scheduled distributions made to the partners during the year, offset by undistributed earnings for the year.

DUE FROM / TO RELATED PARTIES

On July 1, 2005, the Company exchanged all of its common and preferred shares in wholly owned First Toronto Equities Inc. ("FTEI") for preferred shares in a new amalgamated company, Trilon Bancorp Inc. ("TBI"). TBI is wholly owned by Brookfield. Subsequently, on July 1, 2005, the Company purchased, through a subsidiary, all of the preferred shares of The Catalyst Group ("TCG") from TBI for $75 million. The TCG preferred shares were owned by the Company through FTEI prior to the exchange of shares described above. As a result of these transactions, the Company recorded an increase in its contributed surplus of $198 million, representing the excess of consideration received over that given up. In addition, the TCG $177 million junior note that was previously payable to FTEI, and therefore eliminated upon consolidation, is now presented on the balance sheet as Due to related party.

On August 1, 2005, the Company redeemed all of its preferred shares in TBI for $689 million. The consideration is presented on the balance sheet as Due from a related party.

CAPITAL STRUCTURE AND FINANCING

We are committed to maintaining a strong and flexible capital structure that is comprised largely of long-term financial obligations and permanent equity. This enables us to provide financial stability and a low cost of capital to the operations.

We continue to maintain investment grade unsecured issuer ratings from DBRS (BBB High) and Standard and Poor's (BBB), which is influenced by a prudent level of low-cost asset financing and modest levels of corporate debt. The long-life nature of our assets allows us to finance with non-recourse debt and minimal near-term maturities.

The composition of the Company's capital structure is as follows:

	As at December 31	
	2005	2004(1)
Credit facilities, property specific borrowings and term debentures and other	**61%**	60%
Other long-term liabilities	**5%**	5%
Non-controlling interests	**5%**	6%
Shareholders' equity and debt portion of capital securities	**29%**	29%
Total	**100%**	100%

(1) All 2004 comparatives have been restated to reflect the adoption of revisions to Section 3860, Financial Instruments-Disclosure and Presentation and Accounting Guideline 15, Consolidation of Variable Interest Entities.

Overall, the composition of our capital structure as at December 31, 2005 is fairly consistent with that as of December 31, 2004. At December 31, 2005, our weighted average interest rate and term to maturity for long-term debt excluding capital securities were 7.3% and 16.7 years respectively.

During the year, we were successful in securing financing at low rates for an extended duration, hence minimizing liquidity requirements and refinancing risk.

On January 27, 2005, we issued an additional CDN $50 million in Series 1 Canadian unsecured term debentures. These debentures bear interest at 4.65% and mature on December 16, 2009. The $200 million Series 3 corporate debentures were repaid upon maturity in March 2005.

On February 11, 2005, we issued CDN $35 million of senior secured Series 1 first mortgage bonds. These bonds are secured by a first ranking lien on the Pingston Creek Hydro Joint Venture assets, bear interest at a rate of 5.28% payable semi-annually, and mature on February 11, 2015.

On October 6, 2005, the Fund completed a private placement of CDN $225 million of senior secured bonds maturing in 20 years and bearing an interest rate of 5.6% per annum. The bonds are secured by the Lièvre Power assets and were used to repay the GLPT CDN $125 million bridge loan and all outstanding amounts on the GLPT CDN $50 million bank facility.

On December 16, 2005, Brookfield Power New York Finance LP refinanced the $500 million bridge financing obtained to acquire the New York assets in late September of 2004 by issuing three series of a senior secured note for a total amount of $550 million. The agreement is secured by a first ranking lien on all Erie Boulevard Hydropower LP assets. The Series A notes bear an annual interest rate of 5.45% and expire on December 18, 2017. The Series B notes bear an annual interest rate of 5.91% and are due December 16, 2025. The Series C notes bear an annual interest rate of 5.96% and are due December 16, 2030.

As a result of the adoption of AcG 15, as explained in note 3 of the annual consolidated financial statements, we are now consolidating our 75% residual interest in CORHLP, versus the equity accounting method previously used. As a result of this change, the finance debt obligation of CORHLP, amounting to $813 million, was included on our balance sheet. The implicit annual interest rate of the finance debt obligation is 10.30%, and lease payments are due on a semi-annual basis until November 1, 2031. All revenues generated by CORHLP are contractually required to be deposited into a series of trust accounts administered by an independent collateral agent pursuant to a disbursement agreement which provides for the disbursement of funds for operating costs, lease and royalty payments. Under the terms of the disbursement agreement, in May of each year, the funds held in trust for the partners are distributed providing that all the terms of the agreement are satisfied. As of December 31, 2005, there were no restrictions on any partner distributions. Part of the acquisition price of an additional 25% partnership interest in CORHLP from our partners was funded by a note payable, which is secured by the Company's 25% additional partnership interest in CORHLP. The note bears a simple annual interest rate of 5.90% and is repayable, principal and interest, on July 1, 2014.

At December 31, 2005, the Company's total debt was as follows:

US $ millions (unless otherwise noted)	Maturity	Interest rates	Rating	Agency	**2005**	2004
Property specific borrowings						
Great Lakes Power Limited						
First Mortgage Bonds						
Series 1 (CDN $384)	2023	6.60%[1]	A Low	DBRS	**$ 331**	$ 320
Subordinated debt (CDN $115)	2023	7.80%	BBB	DBRS	**99**	96
Great Lakes Power Trust						
First Mortgage Bonds						
Series 1 (CDN $50)	2005	7.33%			**-**	41
Series 2 (CDN $25)	2010	7.55%			**-**	21
Series 3 (CDN $25)	2015	7.78%			**-**	21
Lièvre Power LP senior secured note (CDN $225)	2025	5.56%	A Low	DBRS	**194**	-
Powell River Energy Inc.						
Mortgage bonds (CDN $75)	2009	6.39%	A Low	DBRS	**65**	62
Lake Superior Power						
Senior secured note (CDN $57)	2009	4.39%	BBB High	DBRS	**49**	61
Pontiac Power						
Mortgage loans						
Coulonge LP (CDN $36)	2018	10.26%	Not rated	N/A	**31**	31
Waltham LP (CDN $21)	2020	10.99%	Not rated	N/A	**18**	18
Valerie Falls first mortgage bonds (CDN $32)	2042	6.84%	Not rated	N/A	**28**	27
Mississagi Power first mortgage bonds (CDN $175)	2020	6.92%	A Low	DBRS	**151**	146
Pingston Power Inc. series 1 senior secured bonds (CDN $35)	2015	5.28%	A High	DBRS	**30**	-
GLHA Senior secured notes	2014	5.60%	Not rated	N/A	**125**	125
GLHA bridge facility	2006	US Prime +150bps			**-**	11
Hydro Kennebec senior secured term notes	2008	5.98%	Not rated	N/A	**9**	-
Brookfield Power New York						
Bridge financing facility	2006	LIBOR +100bps			**-**	500
Senior secured notes - Series A	2017	5.45%	A Low	DBRS	**175**	-
Senior secured notes - Series B	2025	5.91%	A Low	DBRS	**250**	-
Senior secured notes - Series C	2030	5.96%	A Low	DBRS	**125**	-
Total – Property specific borrowings					**$ 1,680**	$ 1,480
Term debentures and other						
US Corporate debentures						
Series 3	2005	8.30%[2]			**$ -**	$ 200
CDN Corporate debentures						
Series 1 (CDN $450; 2004 – CDN $400)	2009	4.65%	BBB High	DBRS	**388**	333
Series 2 (CDN $100)	2006	CDOR + 68 bps	BBB High	DBRS	**86**	84
Powell River Energy Inc.						
Shareholders note (CDN $22)	N/A	N/A	Not rated	N/A	**19**	18
CORHLP						
Finance debt obligation	2031	10.30%	Not rated	N/A	**813**	816
Note payable	2014	5.90%	Not rated	N/A	**31**	30
Total – Term debentures and other					**$ 1,337**	$ 1,481
TOTAL DEBT					**$ 3,017**	$ 2,961

1. The Company had entered into an interest rate swap with a notional amount of CDN $284 million. This contract was terminated in February 2005.
2. The Company entered into an interest rate swap for these debentures.

In April 2005, we obtained a $200 million revolving unsecured credit facility for general corporate purposes, which can be drawn upon in Canadian or US dollars to replace the CDN $118 million unsecured credit facility previously held for general corporate purposes. The credit facility bears a floating interest rate, expires on April 29, 2008 and ranks pari passu with all senior unsecured indebtedness. At December 31, 2005, we had drawn $nil on the credit facility but had issued $130 million in letters of credit.

GLPT, a 100% wholly owned subsidiary of the Fund, had available a credit facility of $50 million, which was cancelled on October 6, 2005 and replaced by a CDN $25 million credit facility secured by the Lièvre Power assets. Lièvre Power Limited Partnership ("LPLP") is a 100% wholly owned subsidiary of the Fund and has available this senior secured credit facility of CDN $25 million for general corporate purposes. The credit facility is secured by the power generating assets of LPLP, has a one year term and may be extended for additional individual periods of one year at the request of the borrower. The credit facility bears interest based on prime plus applicable margin. Standby fees, ranging from 15 to 37.5 basis points, are charged on the undrawn balance. If not renewed, the credit facility is due in October 2006.

We provided covenants to certain of our lenders as do most borrowers. As at December 31, 2005, the Company is in compliance with all covenants.

CAPITAL SECURITIES

Capital securities represent long-term subordinated convertible debentures, which are held by Brookfield. The principal portion of the capital securities can be settled, at the Company's option, by issuing a fixed number of our common shares. The Company also has the option to pay the interest in the form of a variable number of our common shares. As a result of new accounting guidelines, these debentures are primarily recorded as debt in our financial statements.

US $ millions		**As at December 31, 2005**			As at December 31, 2004	
	Debt portion of capital securities	**Equity portion of capital securities**	**Total**	Debt portion of capital securities	Equity portion of capital securities	Total
Capital securities, CDN $248	**$ -**	**$ -**	**$ -**	$ 206	$ -	$ 206
Capital securities, US $909 million	**905**	**4**	**909**	913	3	916
Capital securities, US $200 million	**199**	**1**	**200**	-	-	-
Total	**$ 1,104**	**$ 5**	**$ 1,109**	$ 1,119	$ 3	$ 1,122

On April 1, 2005, the CDN $1,100 million capital securities owned by Brookfield were converted into an equivalent of US $909 million. On June 30, 2005, we repaid the CDN $248 million capital securities and issued capital securities totaling $200 million to Brookfield. These debentures bear an annual interest rate of 11.3%, payable quarterly, mature on June 30, 2054, and are convertible in full at the option of Brookfield any time prior to the maturity date into 43.9 million common shares.

For the year ended December 31, 2005, $120 million (2004 - $43 million) was recorded as interest on capital securities on the consolidated statement of income.

SHAREHOLDERS' EQUITY

The Company is authorized to issue an unlimited number of common shares, of which the following were issued and outstanding as at December 31:

US $ millions (except share amounts)	**2005**	2004
101,512,218 (2004 - 101,383,135) Common shares	**$ 422**	$ 419
Deficit	**(215)**	(222)
Contributed surplus	**197**	-
Cumulative translation adjustment	**(53)**	105
	351	302
Capital securities	**5**	3
	$ 356	$ 305

On March 31, 2005, we issued an additional 129,024 common shares to Brookfield as non-cash consideration for the acquisition of the common shares of Harmony Wind. In the third quarter of 2005, we issued another 59 common shares to Brookfield as non-cash consideration for the acquisition of its investment held in FTEI. As of the date of this MD&A, the Company has 101,512,218 common shares issued and outstanding.

The gain on disposition of investments to Brookfield during the year resulted in contributed surplus of $198 million, offset by a loss of $8 million on the disposition of the Company's coal assets. During the year, the Company sold securities of affiliated companies to Brookfield, which resulted in a gain of $1 million recorded in contributed surplus. All shares issued under the Company's stock based compensation plan are Brookfield shares and are recorded as contributed surplus, which represents $6 million in 2005. These transactions are discussed in more detail in the notes to the annual consolidated financial statements.

Dividends paid to holders of common shares totalled $53 million in 2005, compared to $54 million in 2004. During the year ended December 31, 2004, we paid a special dividend of $612 million as a result of the issuance of capital securities. Our policy is to distribute surplus operating cash flows not required for investment in power generating facilities to our shareholders.

CONTRACTUAL OBLIGATIONS

The following table summarizes our significant contractual obligations as of December 31, 2005:

US $ millions	Total	In years 2006-2010	In years 2011-2015	In years 2016-2020	Beyond 2021
Long-term debt	**$ 3,017**	$ 611	$ 205	$ 195	$ 2,006
Capital projects	**253**	253	-	-	-
Purchase obligations	**144**	144	-	-	-
Total	**$ 3,414**	$ 1,008	$ 205	$ 195	$ 2,006

On January 11, 2006, the Company entered into an agreement to acquire two hydroelectric generating facilities in Maine from Rumford Falls Power Company, owned by NewPage Corporation for cash consideration of $144 million. These two run-of-the-river merchant facilities are located on the Androscoggin River and have the capacity to generate approximately 270 GWh of energy per year. This transaction, which is subject to various closing conditions (including regulatory approval), is expected to close in the second quarter of 2006.

On December 28, 2005, we also entered into an agreement to acquire Beaver Power Corporation, which own four hydroelectric generating facilities in Northern Ontario totaling approximately 50 megawatts of generating capacity, for an undisclosed cash consideration. Generating facilities are located on the Groundhog River (19 MW), Shekak River (19 MW), the Serpent River (7 MW) and Aux Sables River (5 MW). This transaction closed on February 17, 2006.

SOURCES OF LIQUIDITY

Given the nature of our operations, the industry in which we operate and our contractual arrangements, our cash margin is stable and provides a strong credit profile. In addition to the risk of variable hydrology conditions, our risk with respect to liquidity arises from the financing required for acquisitions and significant capital projects. We continue to have a strong balance sheet and healthy financial ratios. As at December 31, 2005, we maintained a current cash and cash equivalents balance of $100 million. These factors, combined with the additional available resources noted above, make liquidity for us a negligible risk factor. Given our historical profitability and our ability to manage expenses, we believe that our current resources are adequate to meet our requirements for working capital and capital expenditures through the foreseeable future.

The following table explains the change in our liquidity for the year ended December 31, 2005:

US $ millions	2005	2004
Cash and cash equivalents, beginning of year	**$ 142**	$ 52
Provided by (used in)		
Operating activities	**185**	263
Financing activities	**(69)**	1,600
Investing activities	**(105)**	(1,107)
Distributions	**(53)**	(666)
Cash and cash equivalents, end of year	**$ 100**	$ 142

OPERATING ACTIVITIES

Cash flows from operating activities decreased in 2005 by $78 million as compared with 2004 due to a decrease of $16 million in net income, a decrease of $1 million in non-cash items and a decrease of $61 million in change in non-cash working capital.

The decrease in the net change in non-cash working capital from 2004 to 2005 resulted from the interest accrual on the capital securities of CDN $1,100 million and CDN $248 million as at December 31, 2004, and the impact of the stronger Canadian dollar over the last two years. The impact of these factors is offset by the application of AcG 15 and the disposition of the coal royalty receivable in December 2005.

FINANCING ACTIVITIES

The $69 million of cash used (2004 - $1,600 million of cash provided) in financing activities in 2005, excluding distributions to shareholders, is comprised of the repayments of property specific borrowings, short-term facilities and term debentures for $954 million ($316 million in 2004), primarily offset by $916 million (2004 - $1,102 million) of proceeds from property specific borrowings, term debentures and short-term facilities. In 2005, we repaid $202 million of capital securities (2004 - $nil) and issued $200 million of new capital securities (2004 - $842 million). We also distributed $34 million to the Company's minority shareholders in 2005 (2004 - $31 million).

Investing Activities

In 2005, we used $105 million in investing activities compared to $1,107 million in 2004. We invested $224 million in capital expenditures for the year, which enhanced operations and increased our asset base. Furthermore, the Company invested $113 million in the acquisition of new facilities including Hydro Kennebec, West Delaware, Piney and Deep Creek and Bear Swamp (2004 - $881 million). During the second quarter of 2005, we invested an additional $75 million in preferred shares of Brascan Brazil Limited. Subsequent to the exchange of the FTEI preferred shares for preferred shares in TBI, the Company repurchased all of the preferred shares of The Catalyst Group ("TCG") from TBI for $75 million. These cash outflows were offset by a decrease in demand deposits held with affiliates of $289 million and the sale of securities of $79 million.

Distributions

In 2005, we distributed an amount of $53 million to our shareholders, which is in line with the dividend paid in the previous year. Distributions to our shareholders in 2004 also included a special dividend of $612 million, as a result of the issuance of capital securities.

Off-Balance Sheet Arrangements

Guarantees

In the normal course of operations, we execute agreements that provide for indemnification and guarantees to third parties in transactions such as energy trading and marketing, business dispositions, business acquisitions, capital project purchases, and sales and purchases of assets and services. We have also agreed to indemnify our directors and certain of our officers and employees. The nature of substantially all of the indemnification undertakings prevents us from making a reasonable estimate of the maximum potential amount that we could be required to pay third parties, as many of the agreements do not always specify a maximum amount and the amounts are dependent upon the outcome of future contingent events, the nature and likelihood of which cannot be determined at this time. Historically, we have made no significant payments under such indemnification agreements. We provide guarantees as described in note 27 of the 2005 annual consolidated financial statements. There have been no material changes for the year ended December 31, 2005 to the disclosures related to the guarantees.

Derivative Financial Instruments

The Company uses derivative financial instruments including commodity swaps, interest rate swaps and commodity and foreign exchange forward contracts to manage risk. Derivative financial instruments involve credit and market risk.

Credit risk

Credit risk arises from the potential for a counterparty to default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the defaulted transaction. The Company's financial instruments that are potentially exposed to credit risks are cash equivalents, accounts receivable, investments, demand deposits, accrued levelized revenues and commodity contracts. The Company actively manages its exposure to credit risk by assessing the ability of counterparties to fulfill their obligations under the related contracts prior to entering into such contracts, and regularly monitors these exposures. The Company's contracted power sales are with customers with long-standing credit history or investment grade ratings.

The Company minimizes credit risk with counterparties to derivative financial transactions through the selection, monitoring and diversification of counterparties, use of the International Swaps and Derivatives Association documentation, collateral and other credit risk mitigation techniques. These risks are reviewed on a regular basis and the Company believes the exposures are manageable and not material in relation to its overall business operations.

Commodity price

The Company enters into energy derivative contracts primarily to manage the price risk associated with the sale of generated power at spot prices. The Company links forward electricity sale derivatives to specific periods and markets in which it anticipates generating electricity for sale. A part of the cash flows related to energy are currently hedged until December 2010. The Company also enters into gas derivative contracts for the sale of gas not required in its operations. Cash flows related to gas sales are currently partially hedged until December 2008. Non-hedging commodity swap settlements and unrealized gains and losses are recorded with power generation revenue.

US $ millions	**2005**		2004	
Gain / (loss)	**Recorded fair value of non-hedging swaps**	**Fair value of all swaps**	Recorded fair value of non-hedging swaps	Fair value of all swaps
Energy and gas derivatives				
Forward contracts and swaps				
Commodity derivative asset	**52**	**15**	12	75
Commodity derivative liability	**(68)**	**(204)**	(4)	(74)
	(16)	**(189)**	8	1

In 2005, the Company entered into contracts that do not qualify for hedge accounting. As such, at the end of the reporting period, these contracts are evaluated against market prices (mark-to-market) and an asset or liability is recorded. A total loss of $16 million has been recorded in the 2005 consolidated statement of income (2004 – $8 million gain). Even though these contracts do not qualify for hedge accounting, management believes they are effective in mitigating the Company's exposure to commodity price risk. These contracts are sometimes offset by contracts that are specifically de-designated as hedges. Deferred losses and gains are recorded when a contract is de-designated as a hedge or when a stand-alone contract is marked-to-market; gains or losses are deferred and will be realized upon settlement of the contracts. As at December 31, 2005, the Company has short and long-term assets related to commodity derivatives of $25 million and $33 million, respectively, (2004 - $12 million and $nil) and short and long-term liabilities of $34 million and $34 million, respectively, (2004 - $4 million and $nil). The long-term asset includes $6 million that represents a deferred loss on commodity derivatives. The short-term asset is included in the financial statements in "Accounts receivable and other", the long-term asset is included in "Other assets", the short-term liability is included in "Accounts payable and other" and the long-term liability is included in "Other long-term liabilities".

INTEREST RATE

The Company enters into interest rate swaps on its long-term debt. The swap agreements require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. The Company designates its interest rate swap agreements as hedges of the underlying debt. Interest expense is adjusted to include the payments made or received under the interest rate swaps.

In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instruments, any realized or unrealized gain or loss on such derivative instruments is recognized in income. In the event a derivative instrument in a designated hedge relationship is sold, extinguished or matures prior to the termination of the related hedged item, any realized or unrealized gain or loss is recognized in income on the same basis as the underlying hedged item.

All swap agreements were terminated in 2005. The total notional amount of principal underlying interest rate swap contracts as at December 31, 2004 was $437 million.

FOREIGN EXCHANGE

In 2004, prior to its change in functional currency, the Company used foreign exchange contracts and foreign-denominated liabilities to hedge the value of its investments in its foreign self-sustaining subsidiaries. As at December 31, 2005, the Company no longer holds any forward foreign exchange contracts (2004 notional - $310 million). For the fourth quarter of 2005, Canadian denominated liabilities in the amount of $459 million were designated as a hedge of the net investments in Canadian operations. The impact of hedging activities in 2005, as reflected in the cumulative translation adjustment was $23 million.

Refer to note 22 of the 2005 annual consolidated financial statements for the significant elements that gave rise to the change in the cumulative translation adjustment during the year.

Exchange gains and losses arising on the translation of foreign-denominated monetary assets and liabilities in the amount of $6 million (2004 – $3 million) are included in investment and other income.

RELATED PARTY TRANSACTIONS

All related party transactions are consistent with the type of transactions disclosed in the notes to the December 31, 2005 consolidated financial statements. The following table summarizes all significant year-to-date related party transactions:

US $ millions	Twelve months ended December 31	
	2005	2004
Revenues		
Sale of power to Noranda	**$ 49**	$ 119
Physical gas sales to Falconbridge Limited	**1**	10
Sale of power and financial transactions with Brookfield and affiliates	**2**	10
Sale of power to Katahdin Paper Company	**25**	23
Sale of power and tolling agreement with Fraser New Hampshire	**8**	6
	$ 85	$ 168
Investment income and other		
Interest earned on demand deposits and promissory notes with Brookfield	**$ 14**	$ 7
Income from securities with affiliated companies	**14**	21
Income from investments with affiliated companies	**8**	28
	$ 36	$ 56
Expenses		
Interest expense on note payable	**$ 18**	$ -
Interest expense on bridge facility with Brookfield	**-**	4
Income on interest rate swaps with Brookfield	**-**	(5)
Profit sharing with Noranda [1]	**(5)**	(13)
	$ 13	$ (14)

[1] Included in power purchases

As at December 31, 2005, we have demand deposits and promissory notes held with Brookfield totalling $112 million and $26 million respectively (December 31, 2004 - $401 million and $138 million). We also had an $11 million bridge facility with Brookfield as of December 31, 2004 that was repaid during the second quarter of 2005.

On July 1, 2005, the Company exchanged all of its common and preferred shares in wholly owned FTEI for preferred shares in a new amalgamated company, TBI. Refer to the Due from / to related parties discussion on page 8 for details.

On December 27, 2005, the Company sold its coal properties and all related assets and liabilities including any future royalty revenue stream, to Highvale Coal GP Ltd., an affiliated company through common ownership, for consideration of CDN $10 million. The loss upon disposition of US $8 million was recorded as a reduction in contributed surplus, given the related party nature of the transaction.

CRITICAL ACCOUNTING ESTIMATES

The consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles, which require the use of estimates and judgment in reporting assets, liabilities, revenues, expenses and contingencies. In the judgment of management, none of the estimates outlined in note 2 (Summary of Accounting Policies) of the 2005 consolidated financial statements are considered critical accounting estimates as defined in regulation 51-102. Key estimates include determination of accruals, levelized accounting, mark-to-market and derivatives, purchase price allocations, useful lives, asset impairment testing and those relevant to the defined benefit pension and non-pension benefit plans. Estimates are based on historical experience, current trends and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from those estimates.

CHANGES IN ACCOUNTING POLICIES

The notes to the financial statements include a summary of the changes in accounting policies that occurred during the year and that were used in preparation of the consolidated financial statements. Other than the translation of foreign currency, the adoption of the revisions to CICA Handbook Section 3860, Financial Instruments – Disclosure and Presentation and the implementation of Accounting Guideline 15, Consolidation of Variable Interest Entities, there have been no changes to these policies for the year ended December 31, 2005.

RECENTLY ISSUED CANADIAN ACCOUNTING STANDARDS

The Company will be required to adopt the following accounting standards for Canadian generally accepted accounting principle purposes in future years, which includes three new accounting standards (effective for the Company on January 1, 2007) and one new abstract (effective for the Company for interim and annual reporting periods ending after March 31, 2006). The impact of implementing the new standards on the consolidated financial statements is not yet determinable as it will be dependent on the outstanding positions and their fair values at the time of transition. The impact of the new abstract is also not yet determinable as no estimate can be made at this time in relation to the associated fair values.

HEDGES, CICA HANDBOOK SECTION 3865

This new standard specifies the criteria under which hedge accounting can be applied and how hedge accounting can be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a fair value hedging relationship, the carrying value of the hedged item is adjusted by gains or losses attributable to the hedged risk and recognized in net income. This change in fair value of the hedged item, to the extent that the hedging relationship is effective, is offset by changes in the fair value of the derivative. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative will be recognized in other comprehensive income. The ineffective portion will be recognized in net income. The amounts recognized in accumulated other comprehensive income will be reclassified to net income in the periods in which the net income is affected by the variability in the cash flows of the hedged item. In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, foreign exchange gains and losses on the hedging instruments will be recognized in other comprehensive income.

FINANCIAL INSTRUMENTS – RECOGNITION AND MEASUREMENT, CICA HANDBOOK SECTION 3855

Under the new standard, all financial instruments will be classified as one of the following: Held-to-maturity, Loans and Receivables, Held-for-trading or Available-for-sale. Financial assets and liabilities held-for-trading will be measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading, will be measured at amortized cost. Available-for-sale instruments will be measured at fair value with unrealized gains and losses recognized in other comprehensive income. The standard also permits designation of any financial instrument as held-for-trading upon initial recognition.

COMPREHENSIVE INCOME

As a result of adopting these standards, a new category, Accumulated Other Comprehensive Income, will be added to shareholders' equity on the consolidated balance sheet. Major components for this category will include unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation amounts, net of hedging, arising from self-sustaining foreign operations, and changes in the fair value of the effective portion of cash flow hedging instruments.

CONDITIONAL ASSET RETIREMENT OBLIGATIONS, EMERGING ISSUES COMMITTEE ABSTRACT 159

Issued in December 2005 by the Emerging Issues Committee, this abstract requires an entity to recognize the fair value of a legal obligation to perform asset retirement activities, even though the timing and/or method of settlement may be uncertain.

BUSINESS ENVIRONMENT AND RISKS

The unique nature of our hydroelectric operations provides many advantages over other forms of electricity generation. The advantages of hydroelectric power include high level of reliability, low operating costs, operational flexibility to meet ongoing base load electricity needs and peak demands, minimal environmental impact, and reliance on water, a renewable resource.

RELIABILITY

The equipment involved in producing hydroelectric power has relatively few moving parts. Since the process does not include combusting fossil fuels at high temperatures or creating steam, there is minimal wear and tear on the machinery, which contributes to long-life, high reliability and low maintenance requirements. Unplanned outage rates for hydroelectric units are among the lowest in the electricity industry.

LOW OPERATING COSTS

Other than water royalties paid to some governmental authorities, hydroelectric facilities do not have any other significant variable costs, such as fuel costs, which can be quite material and highly volatile for fossil-fuel plants. As well, most hydroelectric plants can be operated remotely by a single person from a centralized control centre. Combined with the low maintenance and outstanding reliability of the equipment, operating expenses are comparatively low.

HIGH OPERATIONAL FLEXIBILITY

Hydroelectric plants can adjust quickly to changes in demand and, depending on the flow of the river and the storage capacity of the reservoirs, hydroelectric plants can service both the base power requirements of its customers as well as their peak power requirements.

LOW ENVIRONMENTAL IMPACT

Hydroelectric generation produces virtually no greenhouse gas emissions or acid rain, both of which have major impacts on the environment. Hydroelectric generation minimizes thermal, chemical, radioactive, water and air pollution as compared to fossil-fuel and nuclear facilities. Instead of producing substantial amounts of residual wastes during the power generation process, hydroelectric generation simply returns the water to the river.

The following represents a summary of the most relevant risk factors relating to our business. This summary contains only certain risk factors and is not all-inclusive. For a more comprehensive description of these and other possible risks such as: the availability of capital to meet obligations, investment eligibility and tax issues, force majeure, operating and capital expenditure costs, leverage, insurance limits, health, safety, environmental and litigation, please see the Non-Offering Prospectus of Brookfield Power Corporation dated March 16, 2005 and filed on SEDAR at www.sedar.com.

HYDROLOGY

The revenues generated by the power systems are directly correlated to the amount of electricity generated. The amount of electricity generated by the power systems is dependent upon available water flows. Accordingly, revenues and cash flows may be affected by low and high water flows in the watersheds. There can be no assurance that the long-term historical water availability will remain unchanged or that a material hydrologic event will not impact the hydrology conditions that exist within the watershed. We strive to mitigate the risk of variable hydrology conditions by acquiring and operating a portfolio of geographically diverse facilities across six regions in North America. The diversified locations of our power generating assets assist in balancing the impact of generation fluctuations in any one geographic region. We also have access to hydrology insurance. Overall, revenues and cash flows may not necessarily be affected by fluctuations in power generation resulting from variable water conditions.

EQUIPMENT FAILURE

There is a risk of equipment failure due to wear and tear, latent defect, design error or operator error, among other things, which could adversely affect revenues and net operating income. Although the power systems have operated in accordance with expectations, there can be no assurance that they will continue to do so. Nevertheless, this risk is substantially mitigated by the proven nature of hydroelectric technology, the design of the plants, the power systems' capital programs, adherence to prudent maintenance programs, comprehensive insurance and significant operational flexibility as a result of having generating units which can operate independently.

FOREIGN EXCHANGE

The price paid for energy produced by our Canadian operations is denominated in Canadian dollars and, therefore, results may be affected by the fluctuations of the Canadian / US dollar exchange rate over time. A material decrease in the value of the Canadian dollar may negatively impact our net operating income. The Canadian operations' operating expenses and financing costs incurred are also denominated in Canadian dollars, thus providing a natural hedge. In addition, we may manage the risk associated with foreign exchange rate fluctuations by entering, from time to time, into forward foreign exchange contracts and engaging in other hedging strategies. To the extent that we engage in risk management activities related to foreign exchange rates, it will then be subject to credit risks associated with the counterparties with which it contracts.

ENERGY PRICE FLUCTUATIONS

A significant portion of our revenue is tied, either directly or indirectly, to the spot market price for electricity in the compatible electricity market we operate in. Electricity price volatility could have a material effect on our business, operating results, financial condition or prospects. We endeavour to maximize the stability and predictability of our power generating revenues by contracting future power sales to minimize the impact of price fluctuations, by diversifying watersheds, and by utilizing water storage reservoirs to minimize fluctuations in annual generation levels.

Through our wholly owned subsidiary Brookfield Energy Marketing Inc. ("BEMI"), formerly Brascan Energy Marketing Inc., we actively manage our energy production and sales, partly through physical and financial contracts, mitigating the impact of price volatility. While 78% of our power is under contract for the next year, we will still benefit from the higher price energy environment by opportunistically dispatching our non-contracted power. The remaining power is sold on a wholesale basis. Due to the low variable cost of hydroelectric power and the ability to concentrate generation during peak pricing periods, we are able to generate attractive margins on uncommitted capacity. Our PPAs have an average term of 14 years and counterparties are almost exclusively customers with long-standing credit history or investment grade ratings. Our policy is to use financial contracts which typically have a term of less than two years to lock in the future price of uncommitted power we are reasonably certain to generate. This approach provides an appropriate level of revenue stability, without exposure to undue risk of contractual shortfalls, and provides the flexibility to enhance profitability through the production of power during peak price periods. These activities are closely monitored through risk management policies. However, there is a transaction risk associated with these activities that could result in losses in extraordinary circumstances. From time-to-time, BEMI may take advantage of very short-term arbitrage opportunities when hourly prices diverge between interconnected markets in its area of operation.

The following table sets forth our contract profile over the next five years, assuming long-term average:

Years ended December 31	2006	2007	2008	2009	2010
Generation (GWh)					
Contracted:					
Power sales agreement	5,589	5,783	5,712	4,428	4,412
Financial contracts	3,684	2,886	497	293	287
Uncontracted	2,600	3,417	5,877	6,911	6,933
	11,873	12,086	12,086	11,632	11,632
Contracted revenues (US $millions)	597	583	446	375	375
Price ($/MWh)	64	67	72	80	80

REGULATORY REGIME AND GOVERNMENT PERMITS

The operation of our Company's generation assets is subject to regulation. Water rights are generally owned by governments which reserve the right to control water levels. Any new law or regulation could require additional expenditure to achieve or maintain compliance. Operations that are not currently regulated may become subject to regulation. Because legal requirements are frequently changed and are subject to interpretation, we are unable to predict the ultimate cost of compliance with these requirements or their effect on operations. Some of our operations are regulated by government agencies that exercise discretionary power conferred by statutes. Because the scope of such authority is uncertain and may be inconsistently applied, we are unable to predict the ultimate cost of compliance with these requirements or their effect on operations. The failure of our Company to obtain or maintain all necessary licenses, leases or permits, including renewals thereof or modifications thereto, may adversely affect our ability to generate income.

CREDIT

We are exposed to credit-related losses in the event of non-performance by counterparties to the financial instruments and physical electricity and gas trades.

LABOUR RELATIONS

While our labour relations have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment cannot be assured. In the event of a labour disruption such as a strike or lock out, the ability of the assets to generate income may be impaired. Our current collective agreements expire periodically and there are no assurances that we will be able to renew collective agreements without a labour disruption.

QUARTERLY ANALYSIS OF OPERATING RESULTS

Net operating income totalled $127 million in the fourth quarter of 2005, representing an increase of $40 million when compared to the same quarter of 2004.

The New York portfolio acquired in September 2004 contributed significantly to the rise in net operating income in the fourth quarter of 2005 when compared to the same period in the prior year, by adding $35 million of additional net operating income primarily as a result of higher than average inflows and higher market prices. Below normal water conditions in Ontario and Louisiana, which negatively impacted net operating income, were more than offset by higher prices and higher generation in Quebec and New England and, as a result, we succeeded at increasing total net operating income in the fourth quarter of 2005.

Overall generation from assets owned at December 31, 2005, before the impact of 2004 and 2005 acquisitions, totalled 1,501 GWh for the quarter, 10% below our long-term average and 3% below the corresponding quarter of 2004, mostly resulting from below average water inflows in our Ontario and Louisiana power systems. Our New England and New York operations partly offset this shortfall and generated more than their long-term averages in 2005, demonstrating the benefit of our diversification strategy.

GENERATION	Three months ended December 31		
Gigawatt hours	**2005**	2004(1)	Long-term average(2)
Assets owned at December 31, 2003			
Ontario	**380**	412	562
Quebec	**366**	281	384
British Columbia	**139**	153	118
New England	**311**	213	242
Louisiana	**82**	265	145
Gas co-generation	**223**	223	216
Total assets owned as of December 31, 2003	**1,501**	1,547	1,667
Acquisitions – 2004	**1,017**	720	786
Acquisitions – 2005	**96**	-	107
	2,614	2,267	2,560

(1) 2004 comparative generation has been restated to reflect the adoption of Accounting Guideline 15, Consolidation of Variable Interest Entities.

(2) Adjusted long-term average for date of acquisition of the facilities.

Variations in quarterly results are correlated with the amount of electricity generated in any given quarter, which is in turn dependent on available water inflows. Other marketing and asset enhancement initiatives also impact the quarterly results.

US $ millions (except generation)	**2005**				2004(1)			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Power generated (GWh)	**2,614**	**1,942**	**2,822**	**2,883**	2,267	1,758	2,137	2,203
Power revenues	**206**	**139**	**200**	**229**	181	148	164	174
Net operating income	**127**	**83**	**119**	**134**	87	79	94	105

(1) All 2004 comparatives have been restated following the retroactive adoption of revisions to Section 3860, Financial Instruments- Disclosure and Presentation and Accounting Guideline 15, Consolidation of Variable Interest Entities.

Financial results for the three months ended December 31, 2005 compared to 2004 are shown in the following table:

US $ millions	**2005**			2004(1)		
	GWh	**Revenue**	**Net operating income**	GWh	Revenue	Net operating income
Hydroelectric generation						
Ontario	**380**	**$ 27**	**$ 21**	412	$ 25	$ 18
Quebec	**366**	**18**	**14**	281	11	8
British Columbia	**154**	**5**	**3**	169	4	3
New England	**343**	**19**	**14**	245	11	7
New York	**1,014**	**70**	**53**	672	37	18
Louisiana	**82**	**20**	**16**	265	32	27
Sub-total	**2,339**	**159**	**121**	2,044	120	81
Gas co-generation	**227**	**21**	**10**	223	15	5
Transmission and Distribution	**n/a**	**9**	**6**	n/a	7	3
Other	**48**	**17**	**(10)**	-	39	(2)
TOTAL	**2,614**	**$ 206**	**$ 127**	2,267	$ 181	$ 87
Hydroelectric revenue / MWh (in $)		**$ 67.98**			$ 58.71	

(1) All 2004 comparatives have been restated to reflect the adoption of revisions to Section 3860, Financial Instruments- Disclosure and Presentation and Accounting Guideline 15, Consolidation of Variable Interest Entities.

ONTARIO

In Ontario, generation totalled 380 GWh, a decrease of 8% from the same quarter in 2004. However, quarterly revenues were $2 million higher than last year, as a result of higher average energy prices, effective dispatch strategies and the favourable impact of the Canadian dollar exchange rate. Costs have remained stable, thus providing for an additional $3 million in net operating income.

QUEBEC

In Quebec, generation during the fourth quarter totalled 366 GWh compared to 281 GWh for the same period last year. Improved hydrology conditions, combined with higher energy prices, contributed to an increase in revenue of $7 million, from $11 million in the fourth quarter of 2004, to $18 million for the same quarter of 2005. Costs in this region have remained relatively stable, thus providing for an additional $6 million in net operating income.

BRITISH COLUMBIA

In British Columbia, generation amounted to 154 GWh for the fourth quarter of 2005 compared to 169 GWh for the same period of 2004, a decrease of 9%. Revenue for the fourth quarter of 2005 increased by $1 million compared to the same quarter of 2004, primarily as a result of the stronger Canadian dollar. Costs remaining relatively stable resulted in a comparable net operating income of $3 million for both the fourth quarter of 2004 and 2005.

NEW ENGLAND

In New England, power generation contributed $19 million of revenue compared to $11 million for the same period last year. Power generated during the fourth quarter increased by 40% from 245 GWh in 2004 to 343 GWh in 2005. Contributions from the Hydro Kennebec and Fife Brook facilities acquired in 2005, combined with higher generation and higher energy prices resulted in an increase of $8 million in revenue over the same period of 2004. As a result of these acquisitions, costs have increased by $1 million compared to the same period from last year. Overall, our New England operations generated $14 million of net operating income in 2005, an increase of 100%.

NEW YORK

In New York, power generation increased from 672 GWh in the fourth quarter of 2004 to 1,014 GWh for the same period of 2005, an increase of 51%. The increase in power generation, combined with a significant increase in energy prices, contributed to a positive revenue variation of 89% from last year. Costs have decreased by $2 million primarily due to lower property taxes compared to the same quarter of the prior year. As a result, the net operating income for the region increased by 194% to $53 million.

LOUISIANA

Generation in Louisiana totalled 82 GWh during the fourth quarter of 2005, 69% below the 265 GWh generated during the same period of 2004. Lower generation was a direct result of poor hydrology conditions, which contributed to the decrease in revenue from $32 million for the fourth quarter of 2004 to $20 million in 2005. Costs have remained fairly stable, resulting in a $11 million decrease in net operating income as compared to last year.

CO-GENERATION

Co-generation facilities contributed 227 GWh in the fourth quarter of 2005 versus 223 GWh during the same period of 2004. Higher gas re-sales and the favourable impact of the Canadian dollar exchange rate positively impacted our revenue. The combination of higher revenue and comparable operating costs resulted in a higher fourth quarter net operating income of $5 million in 2005.

TRANSMISSION AND DISTRIBUTION

Revenue from the transmission and distribution business increased by $2 million, mainly explained by a stronger Canadian dollar and a higher rate base for revenue approved by the Ontario Energy Board in 2005. Costs have remained relatively stable, decreasing by $1 million, thus providing for an additional $3 million in net operating income.

OTHER

Other includes the New England pump storage facility, arbitrage revenues, power sales to an affiliate and corporate administration costs. The pump storage facility acquired in 2005 contributed 48 GWh of generation, $17 million of revenue and $1 million of net operating income.

NET INCOME ANALYSIS

The Company's net income for the fourth quarter totalled $20 million, an increase of $27 million from the net loss of $7 million for the same quarter in the prior year. The increase in net income is primarily the result of a higher net operating income, offset by lower investment income, higher interest expenses and financing fees and a decrease in the provision for income taxes.

US $ millions	Three months ended December 31	
	2005	2004[1]
Net operating income	**$ 127**	$ 87
Investment income and other	**4**	19
	131	106
Interest and financing fees	**61**	47
Depreciation and amortization	**25**	27
(Recovery of) provision for income taxes	**(8)**	18
Non-controlling interests	**1**	4
Net income before interest on capital securities	**52**	10
Interest on capital securities	**32**	17
Net income (loss)	**$ 20**	$ (7)

(1) All 2004 comparatives have been restated to reflect the adoption of revisions to Section 3860, Financial Instruments- Disclosure and Presentation and Accounting Guideline 15, Consolidation of Variable Interest Entities.

INVESTMENT AND OTHER INCOME

Investment and other income decreased by $15 million largely due to the sale of the investments held in FTEI.

INTEREST AND FINANCING FEES

US $ MILLIONS	Three months ended December 31	
	2005	2004[1]
Ontario	**$ 6**	$ 5
Quebec	**4**	3
British Columbia	**2**	2
New England	**2**	2
New York	**12**	6
Louisiana	**25**	21
Transmission and Distribution	**5**	2
Other businesses	**5**	6
Total	**$ 61**	$ 47

(1) 2004 comparative interest and financing fees have been restated to reflect the adoption of Accounting Guideline 15, Consolidation of Variable Interest Entities.

Interest and financing fees increased by $14 million compared to the same period in the prior year. In New York, the increase of $6 million is mostly attributable to a higher variable interest rate on the $500 million bridge financing obtained to acquire the New York assets in late September of 2004. This loan was refinanced by $550 million of senior secured notes on December 16, 2005. The increase of $4 million in Louisiana is related to interest payable on a note due to an affiliate of Brookfield Power.

DEPRECIATION AND AMORTIZATION

US $ MILLIONS	Three months ended December 31	
	2005	2004(1)
Ontario	**$ 4**	$ 5
Quebec	**2**	1
British Columbia	**1**	1
New England	**3**	2
New York	**6**	6
Louisiana	**3**	3
Transmission and Distribution	**3**	6
Other businesses	**3**	3
Total	**$ 25**	$ 27

(1) 2004 comparative depreciation and amortization have been restated to reflect the adoption of Accounting Guideline 15, Consolidation of Variable Interest Entities.

Depreciation and amortization for the fourth quarter of 2005 totalled $25 million, which is comparable to the depreciation and amortization for the same period in 2004.

NON-CONTROLLING INTERESTS

Non-controlling interests relate to income associated with the non-controlling interests in the Company's consolidated entities. The decrease of $3 million in the fourth quarter of 2005 is related to lower quarterly net income resulting mostly from below average hydrology conditions in Louisiana.

PROVISION FOR INCOME TAXES

The provision for income taxes changed from an expense of $18 million in the fourth quarter of 2004 to a recovery of $8 million in the fourth quarter of 2005. This reduction of $26 million is primarily related to provisions for income taxes on lower taxable income, as well as a provision for a potential tax reassessment that was accounted for in the fourth quarter of 2004.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This MD&A may contain forward-looking statements concerning the Company's business and operations. Forward looking statements can be identified by the use of words, such as "plans", "expects", or "does not expect", "is expected", "budget", "scheduled", "estimates", "forecasts", "intends", "anticipates", or "does not anticipate", or "believes" or variations of such words and phrases or state that certain actions, events or results "may", "could", "would", "might" or "will" be taken, occur or be achieved. Forward looking statements involve assumptions and known and unknown risks, uncertainties and other factors which may cause the actual results or performance to be materially different from any future results or performance expressed or implied by the forward statements. More details relating to risk factors can be found in the section entitled Business Environment and Risks on page 16.

Examples of such statements include, but are not limited to factors relating to production and the business, financial position, operations and prospects for the Company. They include (1) the Company's level of generation; (2) the Company's cost of production; (3) interest rates as they bear on the Company's indebtedness; (4) planned capital expenditures; (5) the impact of changes in the Canadian dollar on the Company's costs and results of operations; (6) the negotiation of collective agreements with its unionized employees; (7) business and economic conditions; (8) the legislation governing air emissions, discharges into water, waste, hazardous materials and workers' health and safety as well as the impact of future legislation and regulations on expenses, capital expenditures and restrictions on operations; and (9) regulatory investigations, claims, lawsuits and other proceedings. Actual results and developments are likely to differ, and may differ materially, from those expressed or implied in the forward-looking statements contained herein and as such, you are cautioned not to place undue reliance on these forward-looking statements.

These forward-looking statements represent our views as of the date of this MD&A. While the Company anticipates that subsequent events and developments may cause the Company's views to change, the Company disclaims any obligation to update these forward-looking statements. These forward-looking statements should not be relied upon as representing the Company's views as of any date subsequent to March 3, 2006, the date of this MD&A.

Donald Tremblay
Senior Vice President and Chief Financial Officer