



Direct Dial: (416) 216-2311
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Toronto, July 8, 2009

DELIVERED

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700, PO Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

**RE: Fortis Ontario Inc. Purchase of Shares of Great Lakes Power Distribution Inc.
Section 86 Application/Section 81 Notice (*Ontario Energy Board Act, 1998*)**

On June 23, 2009, FortisOntario Inc. ("FortisOntario") and Brookfield Renewable Power Inc. ("BRPI") reached an agreement whereby BRPI will sell all of the issued and outstanding shares of Great Lakes Power Distribution Inc. ("GLPD") to FortisOntario. Pursuant to sections 86 and 81 of the *Ontario Energy Board Act, 1998* (as amended), please find enclosed six hard copies of:

- (a) an application for an Order granting leave to FortisOntario to acquire the voting securities of GLPD (a licensed electricity distributor) (the "Section 86 Application");
- (b) a notice of proposal by FortisOntario (and its electricity affiliate Fortis Properties Corporation) related to the acquisition of the shares of GLPD (the "Section 81 Notice"); and
- (c) a Summary of Section 86 Application and Section 81 Notice.



We have also provided a copy of all three documents electronically via the Board's Regulatory Electronic Submission System (RESS). In addition to myself, please ensure that the following two individuals are also copied on all correspondence:

Mr. R. Scott Hawkes
Vice-President, Corporate Services,
General Counsel & Corporate Secretary
FortisOntario Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, ON L2A 5Y2
Tel: (905) 994-3642
Fax: (905) 994-2211
Email: scott.hawkes@fortisontario.com

Mr. Doug Bradbury
Director, Regulatory Affairs
FortisOntario Inc.
1130 Bertie Street
P.O. Box 1218
Fort Erie, ON L2A 5Y2
Tel: (905) 994-3634
Fax: (905) 994-2207
Email: doug.bradbury@cnpower.com

Please note that Appendices D and F are being filed today in confidence, in accordance with the Board's Practice Direction on Confidential Filings.

Yours truly,

A handwritten signature in blue ink, appearing to read 'RJ King', with a stylized flourish at the end.

Richard J. King

Encls.

cc: S. Hawkes (FortisOntario)
D. Bradbury (FortisOntario)
C. Keizer (Torys)
A. Moore (Davies)

Summary

SUMMARY OF SECTION 86 APPLICATION AND SECTION 81 NOTICE

This summary provides an overview of: (a) the application (the “Section 86 Application”) by FortisOntario Inc. (“FortisOntario”), pursuant to section 86 of the *Ontario Energy Board Act, 1998* (“OEB Act”); and (b) FortisOntario’s notice in respect of the acquisition of an interest in a distribution system, pursuant to section 81 of the OEB Act (the “Section 81 Notice”).

1. THE PARTIES TO THE TRANSACTION

(i) FortisOntario

FortisOntario, which is headquartered in Fort Erie, Ontario, owns and operates generation, transmission and distribution businesses in the province of Ontario. It is the Ontario-based subsidiary of Fortis Inc., which is the largest investor-owned distribution utility in Canada. For a comprehensive description of FortisOntario and its Electricity Sector Affiliates (as defined in the Section 86 Application), refer to the attached Section 86 Application, responses to questions 1.3.1 and 1.3.2.

(ii) Brookfield Renewable Power Inc. (“BRPI”)

BRPI, a wholly-owned subsidiary of Brookfield Asset Management Inc. (“BAM”), has more than 100 years of experience as an owner, operator and developer of hydroelectric power facilities. Its total portfolio includes more than 160 generating facilities with approximately 4,000 MW of capacity. BRPI's operations are primarily located in North America and Brazil, with the assets held through various subsidiaries. For a more comprehensive description of BRPI, refer to the attached Section 86 Application, responses to questions 1.3.1 and 1.3.2. Descriptions of BRPI’s Electricity Sector Affiliates are set out in **Appendix A**.

(iii) Great Lakes Power Distribution Inc. (“GLPD”)

The proposed transaction that gives rise to this Section 86 Application and Section 81 Notice is BRPI’s proposed sale of all the issued and outstanding shares in GLPD (a licensed distributor) to

FortisOntario. Thus, although not a “party” to the transaction (i.e., not the vendor or purchaser of the shares), it is appropriate to provide a description of GLPD.

GLPD is a wholly-owned subsidiary of BRPI. GLPD was recently established to hold the distribution assets of Great Lakes Power Limited (“GLPL”), which had been a vertically-integrated utility that owned and operated generation and distribution, and was licensed to operate the transmission system of Great Lakes Power Transmission LP (“GLPTLP”). The transfer of GLPL’s distribution assets into GLPD (to create a stand-alone distribution company) was completed on July 1, 2009, following Ontario Energy Board (“OEB”) approval granted on May 5, 2009 (OEB Case Number EB-2009-0073). GLPD’s distribution system covers an area of approximately 14,200 square kilometres in a remote area of northern Ontario, north and east of Sault Ste. Marie, and serves approximately 11,600 customers. It consists of 1,705 pole kilometres of lines and 1,823 circuit kilometres of lines with voltages ranging from 2.4kV to 44kV. GLPD has 13 distribution supply points from the GLPTLP transmission system and 17 sub-transmission distribution substations. GLPD’s Electricity Distribution Licence (ED-2009-0072) is attached hereto as **Appendix B**.

2. THE SHARE PURCHASE TRANSACTION

Pursuant to a Share Purchase Agreement executed by FortisOntario, BRPI and Fortis Inc. (as guarantor of FortisOntario’s obligations) on June 23, 2009, FortisOntario agreed to purchase all the issued and outstanding shares of GLPD from BRPI, subject to receiving approval from the OEB (the “proposed Share Purchase Transaction”).

The proposed Share Purchase Transaction triggers the attached Section 86 Application and Section 81 Notice, for the following reasons:

- Subsection 86(2), paragraph (a) of the OEB Act states that no person, without first obtaining an order from the OEB granting leave, shall acquire such number of voting securities of a distributor that (together with voting securities already held by such person and one or more affiliates or associates of that person) will in the aggregate exceed 20 per cent of the voting securities of the distributor. Because the proposed Share Purchase

Transaction involves the purchase by FortisOntario of 100% of the voting securities of GLPD (a licensed distributor), leave of the OEB is required under section 86 of the OEB Act.

- Section 81 of the OEB Act states that no generator or affiliate of a generator shall acquire an interest in a distribution system or purchase shares of a corporation that owns a distribution system in Ontario unless it has first given notice of its proposal to do so to the OEB, and the OEB either: (a) does not issue a notice of review of the proposal within 60 days of the filing of the notice; or (b) approves the proposal under section 82 of the OEB Act. Both FortisOntario and an affiliate of FortisOntario (Fortis Properties Corporation (“FPC”)) own and operate generation facilities in Ontario (and are both licensed as electricity generators by the OEB). Consequently, the proposed Share Purchase Transaction gives rise to the attached Section 81 Notice.

The proposed Share Purchase Transaction would not trigger the need for a new or amended Electricity Distribution Licence. GLPD will continue to own or operate the distribution system pursuant to Electricity Distribution Licence ED-2009-0072. There will be no rate harmonization process or consolidation of GLPD with any other electricity distributor as a consequence of the proposed Share Purchase Transaction.

The cash consideration for the shares being purchased by FortisOntario is approximately \$68 million, subject to adjustments to be made in accordance with the Share Purchase Agreement.

3. SECTION 86 APPLICATION (THE “NO HARM” TEST)

The test established by the OEB in evaluating applications under section 86 of the OEB Act is one of “no harm”. In other words, the transaction that gives rise to the section 86 application should result in no harm (either in terms of rates, service quality or reliability) to ratepayers.

The proposed Share Purchase Transaction satisfies the OEB's "no harm" test for the following reasons:

- (a) there are no material incremental costs to GLPD arising from the proposed Share Purchase Transaction;
- (b) the transfer of the GLPD shares from BRPI to FortisOntario is rate neutral; and
- (c) the transfer of the GLPD shares from BRPI to FortisOntario will have no operational impacts (i.e., service quality and reliability will not be adversely affected).

These reasons are expanded below.

a. Incremental Costs

GLPD (the regulated utility) is not incurring any material transactional costs in connection with the proposed Share Purchase Transaction. GLPD is not a party to the transaction. Its parent corporation (BRPI) and FortisOntario are the parties to the Share Purchase Transaction (along with Fortis Inc., as guarantor). Transaction costs will be borne by the respective parties to the proposed Share Purchase Transaction, and not GLPD. In addition, the proposed Share Purchase Transaction will not result in any other material incremental costs to GLPD (i.e., operating and maintenance costs, capital expenditures, depreciation, taxes, etc.).

b. Rate Neutrality

Because there will be no material transactional or other incremental costs associated with the proposed Share Purchase Transaction, no such costs will be passed on to GLPD distribution customers. Consequently, there will be no harm to distribution ratepayers as a result of the proposed Share Purchase Transaction.

c. Operational Neutrality

The proposed Share Purchase Transaction should have no impact on distribution operations. The electricity distribution services currently being provided to GLPD customers will continue in the same manner as in the past. The same assets and employees (with the exception of some senior management) providing service today would be used and employed after the transfer of shares to

FortisOntario. There will be no adverse change to GLPD's distribution service quality or reliability as a result of the proposed Share Purchase Transaction.

4. SECTION 81 NOTICE (IMPACT ON COMPETITION)

Section 81 of the OEB Act is meant to provide the regulator with notice of any transaction that involves entities operating in both the competitive (i.e., generation) and monopoly (i.e., distribution and transmission) parts of the electricity sector in Ontario. The restructuring of the Ontario electricity market a decade ago is premised on the principle of "open access" by generators to Ontario's transmission and distribution systems. Proper implementation of this principle requires the clear separation of the competitive and regulated functions in the electricity sector. Section 81 of the OEB Act provides the OEB with the ability to oversee and review transactions that have the potential to impact upon the separation of the competitive and monopoly businesses.

The proposed Share Purchase Transaction triggers the Section 81 Notice because FortisOntario (the proposed purchaser of the shares of GLPD, an electricity distributor) owns and operates generation facilities in Ontario, and is affiliated with FPC, which also owns and operates generation facilities in Ontario.

The proposed Share Purchase Transaction will not adversely impact the separation of monopoly and competitive functions in the Ontario electricity sector, for the following reasons:

- The current sole shareholder of GLPD also has Electricity Sector Affiliates that own and operate generation facilities in Ontario. GLPD is a corporate entity that operates on a stand-alone basis relative to its affiliates in the electricity generation business, and GLPD's sole function is to own and operate its distribution system. That stand-alone distribution function would continue, should the proposed Share Purchase Transaction be approved by the OEB (and FortisOntario thereby becomes the sole shareholder of GLPD).

- FortisOntario is already the sole shareholder of two licensed electricity distributors in Ontario (Canadian Niagara Power Inc. (“CNPI”) and Cornwall Street Railway, Light and Power Company Limited (“Cornwall Electric”)). CNPI and Cornwall Electric are separate corporate entities from FortisOntario (and from each other). CNPI and Cornwall Electric each own and operate their respective distribution systems as stand-alone distribution companies.
- The generation facilities owned and operated by FortisOntario and FPC are not physically connected to GLPD’s distribution system.
- There are no issues of market power in the electricity generation business that arise as a result of the proposed Share Purchase Transaction.

Section 86 Application



Application Form for Applications under Section 86 of the *Ontario Energy Board Act, 1998*

Application Instructions

1. Purpose of this Form

This form is to be used by parties applying under section 86 of the *Ontario Energy Board Act, 1998* (the "Act"). Please note that the Board may require information that is additional or supplementary to the information filed in this form and that the filing of the form does not preclude the applicant from filing additional or supplementary information.

For applications made under section 86(1)(b) of the Act that involve the sale of assets between licensed distributors or transmitters, the applicant must use the application form for Applications Under Section 86(1)(b) of the *Ontario Energy Board Act, 1998*. For transactions involving a non-licensed entity, please contact Market Operations at market.operations@oeb.gov.on.ca for further guidance.

Persons required to provide a Notice of Proposal under section 80 or 81 of the Act must also complete the "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" form in addition to this form.

Depending on the nature of the proposed transaction, the parties to the proposed transaction may be required to apply for the cancellation of an existing licence, an amendment to an existing licence, the issuance of a new licence or any combination thereof. Such applications are to be made under separate cover; however, parties may apply for the cancellation of an existing licence, an amendment to an existing licence, the issuance of a new licence or any combination thereof at the same time the parties apply for approval of the proposed transaction.

2. Completion Instructions

The applicant must:

- (a) provide responses to all questions; and
- (b) print and sign two copies of the form.

Please send both copies of the completed form and two copies of the responses and attachments to:

Board Secretary
Ontario Energy Board
P.O Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

If you have any questions regarding the completion of this application, please contact the Market Operations Hotline by telephone at 416-440-7604 or 1-888-632-6273 or e-mail at market.operations@oeb.gov.on.ca.

The Board's "Performance Standards for Processing Applications" are indicated on the "Corporate Information and Reports" section of the Board's website at www.oeb.gov.on.ca. Applicants are encouraged to consider the timelines required to process applications to avoid submitting applications too late. If the submitted application is incomplete, it may be returned by the Board or there may be a delay in processing the application.

Ontario Energy
Board
P.O. Box 2319
2300 Yonge Street
27th Floor
Toronto ON M4P 1E4
Telephone: 1-888-632-6273
Facsimile: (416) 440-7656

Commission de l'énergie
l'Ontario
C.P. 2319
2300, rue Yonge
27^e étage
Toronto ON M4P 1E4
Téléphone: 1-888-632-6273
Télécopieur: (416) 440-7656



Application Form for Applications under Section 86 of the *Ontario Energy Board Act, 1998*

For Office Use Only	
Application Number	EB -
Date Received	

PART I : GENERAL INFORMATION

1.1 Nature of Application

1.1.1 Application Type

- ☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety (section 86(1)(a))
- ☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public (section 86(1)(b))
- ☐ For leave for a transmitter or distributor to amalgamate with any other corporation (section 86(1)(c))
- ☒ For leave for a person to acquire voting securities that will exceed 20% of a distributor or transmitter (section 86(2)(a))
- ☐ For leave for a person to acquire control of a company that holds more than 20% of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of the corporation (section 86(2)(b))

1.1.2 Notice under section 80 or 81 of the Act

Is a notice of proposal required under section 80 or 81 of the Act?

- ☒ Yes
- ☐ No

If yes, the applicant must also file a completed "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" with the Board.

1.2 Identification of the Parties

1.2.1 Name of Applicant

Legal name of the applicant: FortisOntario Inc.

Name of Primary Contact:

Mr. ☒	Mrs. ☐	Last Name	First Name	Initial
Miss ☐	Ms. ☐	Bradbury	Douglas	
Other ☐		Title/Position		
		Director Regulatory Affairs		

Address of Head Office:

City	Province/State	Country	Postal/Zip Code
Fort Erie	Ontario	Canada	L2A 5Y2
Phone Number	Fax Number	E-mail Address	
(905) 994-3634	(905) 994-2207	doug.bradbury@fortisontario.com	

1.2.2 Other Party to the Transaction (if more than one attach a list)

Name of the other party: Brookfield Renewable Power Inc.

Name of Primary Contact:

Mr. ☐	Mrs. ☐	Last Name	First Name	Initial
Miss ☐	Ms. ☒	Bood	Patricia	
Other ☐		Title/Position		
		Secretary, Vice President of Legal Services and General Counsel		

Address of Head Office:

City	Province/State	Country	Postal/Zip Code
Gatineau	Quebec	Canada	J8T 8R3
Phone Number	Fax Number	E-mail Address	
(819) 561-8659	(819) 561-7188	Patricia.Bood@brookfieldpower.com	

1.3 Description of the Business of Each of the Parties

- 1.3.1 Please provide a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity ("Electricity Sector Affiliates").
- 1.3.2 Please provide a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable.
- 1.3.3 Please provide a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.
- 1.3.4 Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction.
- 1.3.5 Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

1.4 Description of the Proposed Transaction

- 1.4.1 Please provide a detailed description of the proposed transaction.
- 1.4.2 Please provide the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.
- 1.4.3 Please attach the financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.
- 1.4.4 Please attach the pro forma financial statements for each of the parties (or if amalgamation, the one party) for the first full year following the completion of the proposed transaction.

1.5 Documentation

- 1.5.1 Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years.
- 1.5.2 Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction.
- 1.5.3 Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.)

1.6 Consumer Protection

- 1.6.1 Please explain whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.
- 1.6.2 Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.
- 1.6.3 Please describe the steps, including details of any capital expenditure plans, that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction.
- 1.6.4 Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times.
- 1.6.5 Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan.
- 1.6.6 If the application is for an amalgamation, please provide a proposal for the time of rebasing the consolidated entity in accordance with the five-year limit set by the Board.
- 1.6.7 Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances), and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs.
- 1.6.8 Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction.
- 1.6.9 Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction.

1.7 Economic Efficiency

- 1.7.1 Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service.

1.8 Financial Viability

- 1.8.1 Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels.

- 1.8.2 If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility.
- 1.8.3 Please provide details of the financing of the proposed transaction.
- 1.8.4 If the proposed transaction involves a leasing arrangement , please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant.
- 1.8.5 Please outline the capital (debt /equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to allow the Board to assess any potential impacts on the utility's financial viability, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed.
- 1.8.6 Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities.

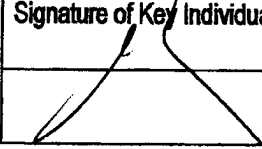
1.9 Other Information

- 1.9.1 If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction.
- 1.9.2 Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates.
- 1.9.3 Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility.
- 1.9.4 Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity.

PART II : CERTIFICATION AND ACKNOWLEDGMENT

2.1.1 Certification and Acknowledgment

I certify that the information contained in this application and in documents provided are true and accurate.

Signature of Key Individual 	Print Name of Key Individual Glen King	Title/Position Vice President, Finance & CAO
	Date July 8, 2009	Company Fortis Ontario Inc.

(Must be signed by a key individual. A key individual is one that is responsible for executing the following functions for the applicant: matters related to regulatory requirements and conduct, financial matters and technical matters. These key individuals may include the Chief Executive Officer, the Chief Financial Officer, other officers, directors or proprietors.)

PART 1: GENERAL INFORMATION

1.1 Nature of Application

See Application Form

1.2 Identification of the Parties

See Application Form

1.3 Description of the Business of Each of the Parties

1.3.1 Please provide a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity (“Electricity Sector Affiliates”).

RESPONSE:

FortisOntario Inc. (“FortisOntario”)

FortisOntario, which is headquartered in Fort Erie, Ontario, owns and operates generation, transmission and distribution businesses in the province of Ontario. Founded in 1892, FortisOntario began generating electricity in 1905 from its Rankine Generating Station located on the Canadian side of the Niagara River, and subsequently began distributing electricity to the Town of Fort Erie in 1907. Most of FortisOntario’s generation assets have been transferred to Fortis Properties Corporation (“FPC”). The exception to this is a 5.5 MW cogeneration district heating plant located in Cornwall, Ontario. This facility is an embedded generator selling district heating to local customers, and electricity to Cornwall Street Railway, Light and Power Company Limited (“Cornwall Electric”). FortisOntario’s electricity distribution business is carried on through two subsidiaries – Cornwall Electric and Canadian Niagara Power Inc. (“CNPI”).

Fortis Inc.: FortisOntario is the Ontario-based subsidiary of Fortis Inc., which is the largest investor-owned distribution utility in Canada. With total assets exceeding \$10 billion and annual revenues exceeding \$3.5 billion, Fortis Inc. serves almost 2,000,000 gas and electricity consumers. Its regulated holdings include a natural gas distribution utility in British Columbia, and electric distribution utilities in five Canadian provinces and three Caribbean countries. Fortis Inc. owns non-regulated hydroelectric generation assets in Newfoundland and Labrador, Ontario, British Columbia, Belize and New York State. Fortis Inc. is a publicly-traded company listed on the TSX (Ticker Symbol: FTS).

CNPI: The electricity distribution systems for the service areas of Fort Erie and Gananoque are owned by CNPI. The electricity distribution system for the service area of Port Colborne is leased by CNPI from Port Colborne Hydro Inc., a wholly-owned subsidiary of the Corporation of

the City of Port Colborne. CNPI-Gananoque serves over 3,000 customers, CNPI-Fort Erie serves over 15,000 customers, and CNPI-Port Colborne serves over 9,000 customers. CNPI is also licenced as an electricity transmission company by the Ontario Energy Board (“OEB”).

Cornwall Electric: FortisOntario also owns Cornwall Electric, which serves over 23,000 electricity distribution customers in Cornwall, Ontario. Cornwall Electric is not connected to the IESO-controlled grid.

Other Distribution: FortisOntario also holds a ten percent (10%) interest in Westario Power Inc. (a 21,000 customer electricity distributor located in mid-western Ontario), Rideau St. Lawrence Holdings Inc. (a 6,000 customer electricity distributor located in southeastern Ontario), and Grimsby Power Inc. (a 10,000 customer electricity distributor located in the Niagara region of Ontario).

FPC: FPC owns and operates five hydroelectric generating stations located on the Rideau Canal system in eastern Ontario with combined capacity of 5.6 MW (embedded generators for CNPI), and a 2 MW hydroelectric generating station located at Rideau Falls in Ottawa. These stations are licensed by the OEB.

Brookfield Renewable Power Inc. (“BRPI”)

BRPI is wholly-owned by Brookfield Asset Management Inc. (“BAM”), and has more than 100 years of experience as an owner, operator and developer of hydroelectric power facilities. Its total portfolio includes more than 160 generating facilities with approximately 4,000 MW of capacity. BRPI's operations are primarily located in North America and Brazil, with the assets held by various subsidiaries. Some of its generation assets are owned through Great Lakes Hydro Income Fund, a publicly traded reporting issuer on the TSX. Descriptions of the affiliates of BRPI (other than GLPD) are set out in **Appendix A**.

Great Lakes Power Distribution Inc. (“GLPD”)

GLPD was recently established to hold the distribution assets of Great Lakes Power Limited (“GLPL”). The transfer of those assets took place on July 1, 2009, following a separate application before the OEB (EB-2009-0073) for which approval was granted on May 5, 2009. GLPD’s distribution system covers an area of approximately 14,200 square kilometres in a remote area of Northern Ontario, north and east of Sault Ste. Marie, serving approximately 11,600 customers. There are 13 distribution supply points from the GLPL transmission system and 17 sub-transmission distribution stations.

1.3.2 Please provide a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable.

RESPONSE:

FortisOntario

A brief description of the geographic territories served by the Electricity Sector Affiliates of FortisOntario is set out below. More specific descriptions are found in the licences noted below. Copies of these licences are not attached to this application since these licences (and their service areas) will be unaffected by the proposed Share Purchase Transaction (as that term is defined in the Summary of Section 86 Application and Section 81 Notice).

CNPI: CNPI is a licenced distributor providing electricity distribution service to the Town of Fort Erie, the City of Port Colborne and the Town of Gananoque. The specific service areas are set out in CNPI's Electricity Distribution Licence (ED-2002-0572).

CNPI is also a licenced transmitter. Its transmission facilities are interconnected with Hydro One Networks Inc. in Niagara Falls, Ontario and provide transmission service to CNPI's distribution facilities in Fort Erie. CNPI's transmission system is also interconnected with US National Grid in New York State. This is more specifically described in its Electricity Transmission Licence (ET-2003-0073).

Cornwall Electric: Cornwall Electric is a licenced distributor providing electricity distribution service to the City of Cornwall. The specific service area is set out in Cornwall Electric's Electricity Distribution Licence (ED-2004-0405).

GLPD

GLPD is a licenced distributor providing electricity distribution services to approximately 11,600 customers in a 14,200 square kilometre service area located north and east of Sault Ste. Marie, Ontario. The geographic territory served by GLPD is set out in detail in GLPD's Electricity Distribution Licence (ED-2009-0072), attached hereto as **Appendix B**.

1.3.3 Please provide a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

RESPONSE:

CNPI-Fort Erie (Year End 2008)

Residential:	14,182
General Service < 50 kW:	1,181
General Service > 50 kW:	144
Unmetered Scattered Load:	109
Sentinel Lighting:	961
Street Lighting:	3,080

CNPI-Port Colborne (Year End 2008)

Residential:	8,151
General Service < 50 kW:	910
General Service > 50 kW:	77
Unmetered Scattered Load:	14
Sentinel Lighting:	38
Street Lighting:	1,991

CNPI-Gananoque (Year End 2008)

Residential:	3,100
General Service < 50 kW:	402
General Service > 50 kW:	35
Unmetered Scattered Load:	6
Sentinel Lighting:	89
Street Lighting:	594

Cornwall Electric (Year End 2008)

Residential:	21,403
General Service:	2,075
Seasonal:	184
Lighting:	5

GLPD

Residential (R1 and R2 subclasses combined):	7,787
Seasonal:	3,707
Street Lighting:	99

1.3.4 Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction.

RESPONSE: The proposed transaction will not affect the geographic service area of GLPD, or any other electricity distributor.

1.3.5 Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

RESPONSE: Please see the corporate charts attached as **Appendix C**.

1.4 Description of the Proposed Transaction

1.4.1 Please provide a detailed description of the proposed transaction.

RESPONSE: FortisOntario is purchasing all the issued and outstanding shares of GLPD from BRPI.

1.4.2 Please provide the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.

RESPONSE: The cash consideration being paid by FortisOntario for the shares is approximately \$68 million[, **subject to adjustment in accordance with the terms of the Share Purchase Agreement**].

1.4.3 Please attach the financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

RESPONSE: Please see the financial statements for FortisOntario for the years ending December 31, 2007 and December 31, 2008 at **Appendix D**.

GLPD, as a newly created corporation, does not have separate legal entity financial statements for prior years. However, audited financial statements for GLPL's distribution business for 2007 and 2008 are provided at **Appendix E**.

1.4.4 Please attach the pro forma financial statements for each of the parties (or if amalgamation, the one party) for the first full year following the completion of the proposed transaction.

RESPONSE: GLPD's pro-forma financial statements for 2010 are attached at **Appendix F**.

1.5 Documentation

1.5.1 Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years.

RESPONSE: As FortisOntario is not a public company, no annual reports are produced. However, the 2007 and 2008 annual reports for Fortis Inc. are provided at **Appendix G**.

As BRPI is not a public company, no annual reports are produced. However, the 2007 and 2008 annual reports for BAM (BRPI's parent) are provided at **Appendix H**.

1.5.2 Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction.

RESPONSE: The documents are:

- Share Purchase Agreement executed June 23, 2009.

1.5.3 Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.)

RESPONSE: Please see response to question 1.3.4 in the Section 81 Notice Form for a complete list of the licenses. The parties to the proposed Share Purchase Transaction and GLPD (to the knowledge of the parties and GLPD) will be in compliance with all licence, code and rule requirements both before and after the proposed Share Purchase Transaction.

1.6 Consumer Protection

1.6.1 Please explain whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

RESPONSE: The proposed Share Purchase Transaction involves GLPD's current sole shareholder (BRPI) transferring all of the shares in GLPD to FortisOntario.

1.6.2 Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.

RESPONSE: The proposed Share Purchase Transaction will have no adverse impact on GLPD's electricity customers with respect to prices, or the adequacy, reliability and quality of GLPD's electricity service. The transfer of shares to FortisOntario is rate neutral, and there will be no harm to GLPD's distribution ratepayers. There will be no adverse change to GLPD's distribution service adequacy, reliability or quality as a result of the proposed Share Purchase Transaction. The same assets and employees providing service today will be used and employed after the share transfer. Please see section 3 of the Summary of Section 86 Application and Section 81 Notice.

1.6.3 Please describe the steps, including details of any capital expenditure plans, that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction.

RESPONSE: The proposed transaction will have no adverse impact on GLPD's operational safety and system integrity. GLPD's operations (and capital programs) will continue in the normal course, consistent with past practice.

1.6.4 Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times.

RESPONSE: As the proposed Share Purchase Transaction is a share transfer, the management, employees (with the exception of some senior management) and assets currently operating GLPD's distribution system will continue in the same capacity. Capital expenditures will remain fairly consistent with past practice in order to maintain quality and reliability of electricity service. The service centres and expected response times will remain unchanged.

1.6.5 Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan.

RESPONSE: The proposed Share Purchase Transaction will not give rise to any rate harmonization process. GLPD's rates will not be harmonized with other distributors owned by FortisOntario. GLPD's distribution system is unique in that it covers a large service area, with relatively few customers. As a result, GLPD's customers are eligible for rate relief under the Rural or Remote Rate Protection ("RRRP") program. Customers served by CNPI and Cornwall Electric are not eligible for RRRP.

1.6.6 If the application is for an amalgamation, please provide a proposal for the time of rebasing the consolidated entity in accordance with the five-year limit set by the Board.

RESPONSE: Not applicable.

1.6.7 Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances), and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs.

RESPONSE: GLPD (the regulated utility) is not incurring any material incremental costs (transactional or ongoing) as a result of the proposed Share Purchase Transaction. GLPD is not a party to the transaction. It's parent corporation (BPRI) and FortisOntario are the parties to the Share Purchase Agreement (along with Fortis Inc., as guarantor). Transaction costs will be borne by the respective parties to the Share Purchase Transaction, and not GLPD.

1.6.8 Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction.

RESPONSE: There will be no changes in distribution or transmission rate levels as a result of the proposed Share Purchase Transaction.

1.6.9 Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction.

RESPONSE: Because the proposed Share Purchase Transaction is a share transfer, GLPD will continue to operate its distribution system in accordance with its current policies, procedures and rates. Thus, the proposed Share Purchase Transaction will have no adverse impact on customers from a cost or operational perspective.

1.7 Economic Efficiency

1.7.1 Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service.

RESPONSE: The proposed Share Purchase Transaction will have no economic efficiency impacts. In the short to medium-term, FortisOntario does not expect any rationalization of GLPD's administrative support functions with those of any other distributors controlled by Fortis Inc. Given the uniqueness of GLPD, and the distance between its service area and those of CNPI

and Cornwall Electric, opportunities for rationalization of operational functions may be minimal. Over the long term (e.g., beyond two years), GLPD should realize some economies of scale in respect of some IT and certain back-office functions (e.g., accounting).

1.8 Financial Viability

1.8.1 Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels.

RESPONSE: A discounted cash flow valuation of GLPD's business, which approximates book value, was prepared as the basis for the purchase price of \$68 million, which includes regulatory assets and working capital (with no debt being assumed).

1.8.2 If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility.

RESPONSE: Not applicable.

1.8.3 Please provide details of the financing of the proposed transaction.

RESPONSE: The proposed Share Purchase Transaction will be financed initially by equity (approximately 40% of purchase price) and an inter-company loan (approximately 60% of purchase price). Should the proposed Share Purchase Transaction be approved, GLPD would issue third party debt to replace the inter-company debt some time in 2010.

1.8.4 If the proposed transaction involves a leasing arrangement, please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant.

RESPONSE: Not applicable.

1.8.5 Please outline the capital (debt/equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to allow the Board to assess any potential impacts on the utility's financial viability, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed.

RESPONSE: GLPD's distribution business is currently financed with equity and inter-company debt. The inter-company debt is considered a form of shareholder equity as it is not part of any

third party borrowing. As noted in the response to question 1.8.3 above, FortisOntario will finance the share purchase with a mix of equity and debt (initially, inter-company debt, but eventually third-party debt) in a ratio that will approximate the OEB's deemed capital structure.

1.8.6 Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities.

RESPONSE: Any potential liabilities in relation to public health and safety matters or any environmental matters are liabilities of GLPD, and would continue to be so after the proposed Share Purchase Transaction closes. Subject to certain conditions, material off-site environmental contamination resulting from pre-closing activities, which would be the responsibility of BRPI.

1.9 Other Information

1.9.1 If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction.

RESPONSE: For FortisOntario, please see resolutions attached as **Appendix I**.

For BRPI, no parent company approval was required, so there are no resolutions.

1.9.2 Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates.

RESPONSE: Other than as noted below, there are no relevant suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding (except proceedings before the Board) have been instituted or threatened against FortisOntario, BRPI or GLPD (or any of their affiliates):

- Application to the Ontario Labour Relations Board by the Power Workers Union relating to successor employer status (BRPI and GLPD included as respondents).

1.9.3 Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remaining utility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility.

RESPONSE: Not applicable.

1.9.4 Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity.

RESPONSE: Please see Summary of Section 86 Application and Section 81 Notice.

Section 81 Notice

Ontario Energy Board
Preliminary Filing Requirements
For Applications under Sections 80 and 81
Of the *Ontario Energy Board Act, 1998*

INSTRUCTIONS:

This form applies to all applicants who are providing a Notice of Proposal to the Ontario Energy Board (the "Board") under sections 80 and 81 of the Ontario Energy Board Act, 1998 (the "Act"), including parties who are also, as part of the same transaction or project, applying for other orders of the Board such as orders under sections 86 and 92 of the Act.

The Board has established this form under section 13 of the Act. Please note that the Board may require information that is additional or supplementary to the information filed in this form and that the filing of the form does not preclude the applicant from filing additional or supplementary information.

PART I: GENERAL MINIMUM FILING REQUIREMENTS

All applicants must complete and file the information requested in Part I.

1.1 Identification of the Parties

1.1.1 Applicant

Name of Applicant	File No: (Board Use Only)	
FortisOntario Inc. ("FortisOntario")		
Address of Head Office 1130 Bertie Street PO Box 1218 Fort Erie, ON L2A 5Y2	Telephone Number (905) 871-0330	
	Facsimile Number (905) 871-8676	
	E-mail Address	
Name of Individual to Contact Douglas Bradbury Director, Regulatory Affairs	Telephone Number (905) 994-3634	
	Facsimile Number (905) 994-2207	
	E-mail Address doug.bradbury@fortisontario.com	

1.2.2 Other Parties to the Transaction or Project

If more than one attach list

Name of Other Party	File No: (Board Use Only)	
Brookfield Renewable Power Inc. ("BRPI")		
Address of Head Office 480 de la Cite Blvd Gatineau, Quebec J8T 8R3	Telephone Number (819) 561-2722	
	Facsimile Number (819) 561-7188	
	E-mail Address	
Name of Individual to Contact Patricia Bood Secretary, Vice-President and General Counsel	Telephone Number (819) 561-8659	
	Facsimile Number (819) 561-7188	
	E-mail Address Patricia.Bood@brookfieldpower.com	

*****Although not a "party" to the proposed Share Purchase Transaction (as that term is defined in the Summary of Section 86 Application and Section 81 Notice), we have included herein information on Great Lakes Power Distribution Inc. ("GLPD"), since it is the regulated electricity distributor (the shares of which are being purchased).***

Name of Other Party	File No: (Board Use Only)	
Great Lakes Power Distribution Inc. ("GLPD")		
Address of Head Office 2 Sackville Road Sault Ste. Marie, Ontario P6B 6J6	Telephone Number (705) 759-7600	
	Facsimile Number (705) 941-5600	
	E-mail Address	
Name of Individual to Contact Patricia Bood Vice-President and Secretary	Telephone Number (819) 561-8659	
	Facsimile Number (819) 561-7188	
	E-mail Address Patricia.Bood@brookfieldpower.com	

1.2 Relationship between Parties to the Transaction or Project

1.2.1	Attach a list of the officers, directors and shareholders of each of the parties to the proposed transaction or project. RESPONSE: FortisOntario Inc. ("FortisOntario") <u>Directors</u> Peter Case (Chair) William J. Daley Geoffrey Hyland Barry V. Perry (CFO, Fortis Inc.) <u>Officers</u> William J. Daley (President and Chief Executive Officer) Glen King (Vice President, Finance and Chief Financial Officer) Angus S. Orford (Vice President, Operations) R. Scott Hawkes (Vice President, Corporate Services, General Counsel & Corporate Secretary) <u>Shareholder</u> Fortis Inc. BRPI <u>Directors</u> Jeffrey Blidner Jack Cockwell	

	Harry A. Goldgut James K. Gray Edward C. Kress Allan O. Kupcis Richard Legault Ronald W. Osborne Jamie Wallace <u>Officers</u> Patricia Bood (Secretary, Vice President of Legal Services and General Counsel) Richard Bordeleau (Senior Vice President, Portfolio Management) Madeleine Bourdon (Vice President, Human Resources and Organizational Development) Lee Butler (Chief Financial Officer, Canadian Operations) Colin Clark (Executive Vice President and Chief Technical Officer) Brian Cook (Chief Financial Officer, Brookfield Energy Marketing Inc.) Harry A. Goldgut (Chairman) Kevin Hall (Chief Information Officer) Stephane Landry (Senior Vice President, Strategy and Market Development) Michel Lecour (Vice President, Asset and Corporate Financings) Andre Legault (Chief Operating Officer, Canadian Operations) Richard Legault (President and Chief Executive Officer) Shaun Logue (Assistant Secretary) Julie Morin (Vice President, Finance) Felipe Pinel (Senior Vice President, Finance) Ralf Rank (Vice President, Corporate Development) Donald Tremblay (Executive Vice President and Chief Financial Officer) Ben Vaughan (Executive Vice President and Chief Operating Officer, North America) <u>Shareholders</u> Great Lakes Holdings Inc. Brookfield Asset Management Inc. GLPD <u>Directors</u> Edward C. Kress Harry A. Goldgut Richard Legault <u>Officers</u> Patricia Bood (Vice President and Secretary) Mark Faught (Business Controller) Duane Fecteau (Director of Administration) Tim Lavoie (General Manager) Richard Legault (President and Chief Executive Officer) Jeff Rosenthal (Chief Operating Officer, Canadian Transmission and Distribution) Donald Tremblay (Executive Vice President)	

	<u>Shareholder</u> Brookfield Renewable Power Inc.	
1.2.2	Attach a corporate chart describing the relationship between each of the parties to the proposed transaction or project and each of their respective affiliates. RESPONSE: Please see the corporate charts attached as Appendix C to the Section 86 Application.	

1.3 Description of the Businesses of Each of the Parties

1.3.1	Attach a description of the business of each of the parties to the proposed transaction or project, including each of their affiliates licenced under the OEB Act to operate in Ontario for the generation, transmission, distribution, wholesaling or retailing of electricity or providing goods and services to companies licenced under the OEB Act in Ontario ("Electricity Sector Affiliates"). RESPONSE: Please see the response to question 1.3.1. in the Section 86 Application.	
1.3.2	Attach a description of the geographic territory served by each of the parties to the proposed transaction or project, including each of their Electricity Sector Affiliates, if applicable, and the geographic location of all existing generation facilities. RESPONSE: Please see the response to question 1.3.2 in the Section 86 Application.	
1.3.3	Attach a breakdown of the annual sales (in C\$, and in MWh) as of the most recent fiscal year end of the existing generation output among the IESO Administered Markets ("IAM"), bilateral contracts, and local distribution companies. RESPONSE: Energy sales from FortisOntario to the IESO Administered Market (Rankine Generating Station) for 2008 were as follows: 655,286 MWh \$31,997,216 Cdn This generation, 653,496 MWh, does not originate at FortisOntario's Rankine generating station. By way of an agreement with Ontario Power	

	Generation, water that would have otherwise been utilized at the Rankine Generating Station is allowed to flow to Ontario Power Generation's facilities and FortisOntario is compensated by an amount equivalent to that which is available at the Rankine Generating Station. Energy sales from FortisOntario to Cornwall Electric (Cornwall District Heating) for 2008: 4,611 MWh \$562,904 Cdn Cornwall District Heating, a subsidiary of FortisOntario, is not connected to the IESO-Controlled Grid and therefore its production does not contribute to the Ontario Primary Demand.	
1.3.4	Attach a list identifying all relevant Board licences and approvals held by the parties to the proposed transaction or project and each of their Electricity Sector Affiliates, and any applications currently before the Board, or forthcoming. Please include all Board file numbers. RESPONSE: Fortis Ontario <u>Board Licences and Approvals Held :</u> • CNPI: ED-2002-0572; ET-2003-0073 • Cornwall Electric: ED-2004-0405 • FortisOntario: EG-2003-0107 <u>Current Applications:</u> There are currently three 2009 Electricity Distribution Rate Applications before the Board • CNPI (Fort Erie): EB-2008-0223 • CNPI (Port Colborne): EB-2008-0224 • CNPI (Gananoque): EB-2008-0222 BRPI <u>Board Licences and Approvals Held :</u> • GLPD : ED-2009-0072 • GLPL: EG-2003-0175 • GLPTLP: ET-2007-0649 • Valerie Falls LP: EG-2003-0177 • MPT: EG-2002-0276 • LSPI: EG-2003-0176 • BPWC: EG-2004-0426 • BPWP LP: EG-2006-0130 • BEMI: EW-2005-0471, ER-2005-0440	

	• BEMLP: EW-2005-0300 • Beaver Power: EG-2002-0408 • Algonquin Power (Nagagami) LP: EG-2006-0072 • Carmichael LP: EG-2006-0070 <u>Current Applications:</u> Other than an application under section 80 of the OEB Act made by BRPI, Great Lakes Hydro Income Fund, Great Lakes Power Trust, GLPL and related entities on July 7, 2009 related to a reorganization of generation assets, there are no current applications before the OEB from any BRPI affiliate. The aforementioned application is unrelated to the proposed Share Purchase Transaction.	

1.4 Current Competitive Characteristics of the Market

1.4.1

Describe the generation capacity (in MW), within the Province of Ontario, of the parties to the proposed transaction or project, including each of their respective Electricity Sector Affiliates, prior to the completion of the proposed transaction or project.

RESPONSE: None of the generation facilities listed below will be impacted by the proposed Share Purchase Transaction.

FortisOntario

Rankine Generating Station is no longer owned by FortisOntario. Cornwall District Heating has a capacity of 5.5 MW.

Fortis Properties Corporation (“FPC”), a subsidiary of Fortis Inc., owns six small hydro plants in eastern Ontario. These plants have a combined capacity of 7.6 MW. Specifically, FPC owns the following hydro electric facilities in Ontario: Jones Falls (near Elgin, Ontario); Brewers Mills (near Seeley’s Bay, Ontario); Kingston Mills (Kingston Mills, Ontario); Washburn (also near Seeley’s Bay, Ontario); Gananoque (Gananoque, Ontario); and Rideau Falls (New Edinburgh, Ontario).

There are no other generating facilities associated with FortisOntario in Ontario.

BRPI

Entity	MWh
GLPL	349.0
Valerie Falls LP	10.0
MPT*	488.0
LSPI	110.0
BPWP LP*	189.0
Beaver Power	29.7
Carmichael*	20.4
TOTAL	1196.1

	*These entities are owned by Great Lakes Hydro Income Fund ("GLHIF"). BRPI's proportionate share of generation produced by these facilities is 50.01% of the capacity listed.																												
1.4.2	Describe the generation market share based on actual MWh production as a percent of the Annual Primary Demand, within the Province of Ontario, of the parties to the proposed transaction or project, including each of their respective Electricity Sector Affiliates, prior to completion of the proposed transaction or project. RESPONSE: FortisOntario As noted, FortisOntario no longer owns the Rankine Generating Station (as of May 1, 2009). Cornwall District Heating, a subsidiary of FortisOntario, is not connected to the IESO-controlled grid and therefore its production does not contribute to the Ontario Primary Demand. BRPI <table border="1"> <thead> <tr> <th>Entity</th><th>MWh (2008)</th><th>% market share</th></tr> </thead> <tbody> <tr> <td>GLPL</td><td>1,591,499</td><td>●</td></tr> <tr> <td>Valerie Falls LP</td><td>58,121</td><td>●</td></tr> <tr> <td>MPT*</td><td>801,624</td><td>●</td></tr> <tr> <td>LSPI</td><td>794,669</td><td>●</td></tr> <tr> <td>BPWP LP*</td><td>456,480</td><td>●</td></tr> <tr> <td>Beaver Power</td><td>120,266</td><td>●</td></tr> <tr> <td>Carmichael*</td><td>84,642</td><td>●</td></tr> <tr> <td>TOTAL</td><td>3,907,301</td><td></td></tr> </tbody> </table> *These entities are owned by GLHIF. BRPI's proportionate share of generation produced by these facilities is therefore 50.01% of the capacity listed. Please note that Annual Primary Demand is no longer calculated by the IESO. As such, we are unable to calculate the generation market share percentage.	Entity	MWh (2008)	% market share	GLPL	1,591,499	●	Valerie Falls LP	58,121	●	MPT*	801,624	●	LSPI	794,669	●	BPWP LP*	456,480	●	Beaver Power	120,266	●	Carmichael*	84,642	●	TOTAL	3,907,301		
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Carmichael*	84,642	●																											
TOTAL	3,907,301																												

1.5 Description of the Proposed Transaction or Project and Impact on Competition - General

1.5.1	Attach a detailed description of the proposed transaction or project, including geographic locations of proposed new transmission or distribution systems, or new generation facilities. RESPONSE: FortisOntario would purchase all of the issued and	

	outstanding shares of GLPD from BRPI. The proposed Share Purchase Transaction will not involve any new transmission or distribution systems, or generation facilities. See also the Summary of Section 86 Application and Section 81 Notice.	
1.5.2	Describe the generation capacity (in MW), within the Province of Ontario, of the parties to the proposed transaction or project, including each of their respective Electricity Sector Affiliates, after the completion of the proposed transaction or project. RESPONSE: The proposed Share Purchase Transaction will not modify the generation capacity noted in section 1.4.1 above.	
1.5.3	Describe the generation market share based on anticipated MWh production as a percentage of the Annual Primary Demand, within the Province of Ontario, of the parties to the proposed transaction or project, including each of their respective Electricity Sector Affiliates, after the completion of the proposed transaction or project. RESPONSE: The proposed Share Purchase Transaction will not modify the generation market share of either party (or their Electricity Sector Affiliates).	
1.5.4	Attach a short description of the impact, if any, of the proposed transaction or project on competition. If there will be no impact on competition, please state the reasons. Cite specifically the impacts of the proposal on customer choice regarding generation, energy wholesalers, and energy retailers. RESPONSE: The proposed Share Purchase Transaction amounts to a share transfer that will maintain the status quo in regard to the operation of GLPD's distribution system, thereby having no impact on competition. There will be no impact on customer choice regarding generation, energy wholesalers, and energy retailers.	
1.5.5	Provide confirmation that the proposed transaction or project will have no impact on open access to the transmission or distribution system of the parties or their affiliates. If open access will be affected explain how and why. RESPONSE: The proposed Share Purchase Transaction amounts to a share acquisition that will have no impact on open access to the distribution facilities at issue. None of the generation owned or operated by FortisOntario or FPC will physically connect to the GLPD distribution system.	

1.6 Other Information

1.6.1	Attach confirmation that the parties to the proposed transaction or project are in compliance with all licence and code requirements, and will continue to be in compliance after completion of the proposed transaction or project. RESPONSE: The parties to the proposed Share Purchase Transaction confirm that, to the best of their knowledge, they are in compliance with all licence and applicable code requirements and will continue to be in compliance after the completion of the proposed Share Purchase Transaction.	

**Part II: SECTION 80 OF THE ACT—TRANSMITTERS AND DISTRIBUTORS
ACQUIRING AN INTEREST IN GENERATORS OR CONSTRUCTING A
GENERATION FACILITY**

All applicants filing a Notice of Proposal under section 80 of the Act must complete and file the information requested in Part II.

2.1 Effect on Competition

2.1.2	Describe whether the proposed generation output will be primarily offered into the IAM, sold via bilateral contracts, or for own use. RESPONSE: Not applicable.	
2.1.3	Provide a description of the generation including fuel source, technology used, maximum capacity output, typical number of hours of operation in a year, and peaking versus base-load character. RESPONSE: Not applicable.	
2.1.4	Provide details on whether the generation facility is expected to sign a “must run” contract with the IESO. RESPONSE: Not applicable.	
2.1.5	Provide details of whether the generation facility is expected to serve a “load pocket”, or is likely to be “constrained on” due to transmission constraints. RESPONSE: Not applicable.	

2.2 System Reliability

Section 2.2 must be completed by applicants who are claiming that the proposed transaction or project is required for system reliability under section 82(2)(b) of the Act.

2.2.1	Provide reasons why the proposal is required to maintain the reliability of the transmission or distribution system. Provide supporting studies. RESPONSE: Not applicable.	
2.2.2	Discuss the effect of the proposal on the adequacy (ability of supply to meet demand) of supply in the relevant control area or distribution region, citing effects on capacity plus reserve levels in comparison to load forecasts. RESPONSE: Not applicable.	
2.2.3	Discuss the effect of the proposal on the security (ability of supply to respond to system contingencies) of supply. RESPONSE: Not applicable	
2.2.4	Provide a copy of the IESO Preliminary System Impact Assessment Report, if completed, and the IESO Final System Impact Assessment Report, if completed. If the IESO is not conducting a System Impact Assessment Report, please explain. RESPONSE: Not applicable.	

PART III: SECTION 81 OF THE ACT—GENERATORS ACQUIRING AN INTEREST IN OR CONSTRUCTING A TRANSMISSION OR DISTRIBUTION SYSTEM

All applicants filing a Notice of Proposal under section 81 of the Act must complete and file the information requested in Part III.

3.1 Effect on Competition

3.1.1	Provide a description of the transmission or distribution system being acquired or constructed. RESPONSE: A description of the distribution system being acquired is set out in detail in GLPD's Electricity Distribution Licence, attached hereto as Appendix B. Also see the description of GLPD set out in the response to section 1.3.1 of the Section 86 Application.	

3.1.2	Provide details on whether the generation facilities owned by the acquiring company are or will be directly connected to the transmission or distribution system being acquired or constructed. RESPONSE: The generation facilities owned by FortisOntario will not be directly connected to the distribution system being acquired.	
3.1.3	Provide details of whether the generation facility is expected to serve a “load pocket”, or is likely to be “constrained on” due to transmission constraints. RESPONSE: Not applicable.	
3.1.4	Provide details on whether the generation facilities are expected to sign a “must run” contract with the IESO. RESPONSE: Not applicable.	

How to Contact the Ontario Energy Board

The Ontario Energy Board is located at:

P.O. Box 2319
2300 Yonge Street, Suite 2701
Toronto, Ontario
M4P 1E4

Telephone:	416-481-1967
Toll Free Number:	1-888-632-6273
Fax:	416-440-7656
Website:	http://www.oeb.gov.on.ca
Board Secretary's e-mail address:	boardsec@oeb.gov.on.ca

Appendix A

APPENDIX “A”

Brookfield Asset Management Inc. (“BAM”)

BAM is focused on property, power and infrastructure assets, with approximately US\$90 billion of assets under management. BAM’s securities trade on the Toronto, New York and Euronext Amsterdam stock exchanges under the symbol BAM.A, BAM and BAMA respectively. BAM is the ultimate parent company to the electricity sector affiliates mentioned below.

Great Lakes Power Transmission Inc. (“GLPT”)

GLPT is the general partner of Great Lakes Power Transmission LP (“GLPTLP”), a limited partner that owns transmission facilities in Northern Ontario that are operated by Great Lakes Power Limited (“GLPL”). GLPT and GLPTLP are indirect subsidiaries of Brookfield Infrastructure Partners L.P. (“BIP”). BAM is a major shareholder of BIP. BIP has securities trading on the New York Stock Exchange under the symbol BIP. GLPT is a licensed transmitter on behalf of GLPTLP pursuant to transmission licence ET-2007-0649. GLPL operates the GL+PTLP transmission facilities pursuant to operator licence EB-2008-0342.

Brookfield Energy Marketing Inc. (“BEMI”)

BEMI, located in Gatineau, Quebec, is wholly owned by BRPI and conducts most of BRPI’s wholesale energy marketing business in Canada and the United States. It manages the scheduling of BRPI’s generating assets, sells power into the applicable wholesale electricity markets and enters into short-term financial contracts and power purchase agreements on behalf of the relevant entities. BEMI is a licensed energy wholesale marketer and retailer under OEB licences EW-2005-0471 and ER-2005-0440.

Brookfield Power Wind Prince LP (“BPWP LP”)

BPWP LP owns the Prince Wind Energy Project, a wind farm west of Sault Ste. Marie located in the townships of Dennis, Pennefather, Korah, Aweres and Prince, in the District of Algoma in the Province of Ontario. It is owned by BRPI’s publicly traded subsidiary, Great Lakes Hydro Income Fund. It is a licensed electricity generator (EG-2006-0130).

Brookfield Power Wind Corporation (“Brookfield Wind”)

Brookfield Wind has been actively involved in the development of wind power projects in Ontario for many years. Brookfield Wind is a licensed electricity generator (EG-2004-0426), but does not currently have any operating generation.

Valerie Falls General Partner Limited (“Valerie GP”)

Valerie GP is the general partner of Valerie Falls Limited Partnership (“Valerie LP”), a limited partnership generating electricity through its 10 MW hydroelectric station on the Seine River at Valerie Falls, three miles north of Atikokan in northwestern Ontario. Valerie GP is a licensed generator on behalf of Valerie LP pursuant to licence EG-2003-0177. Brookfield Renewable Power holds a 65% controlling interest in Valerie GP. The other 35% interest in Valerie GP is held by Seine River Power Inc. (“Seine”), a wholly owned subsidiary of Brookfield Renewable Power. Valerie LP is held 99.99% by Brookfield Renewable Power and 0.01% by Valerie GP.

Mississagi Power Trust (“MPT”)

MPT generates electricity through four hydroelectric facilities: the Aubrey Falls Generating Station, the George W. Rayner Generating Station, the Wells Generating Station and the Red Rock Falls Generating Station. It is owned by Brookfield Renewable Power’s publicly traded subsidiary, Great Lakes Hydro Income Fund. MPT is a licensed generator pursuant to OEB licence EG-2002-0276.

Lake Superior Power Inc. (“LSPI”)

LSPI’s cogeneration facility is located in Sault Ste. Marie, Ontario. Lake Superior Power Limited Partnership (“Lake Superior Power LP”) is a limited partnership formed to develop and operate a 110 MW natural gas-fired cogeneration plant in Sault Ste. Marie, Ontario. Brookfield Renewable Power is the sole limited partner in the Lake Superior Power LP. The general partner is LSPI, which holds a 1% interest in the project. Brookfield Renewable Power is the sole shareholder of LSPI. LSPI is a licensed generator on behalf of Lake Superior Power LP pursuant to OEB licence EG-2003-0176.

Beaver Power Corporation (“Beaver Power”)

The hydroelectric facilities of Beaver Power are located in northern Ontario. Beaver Power directly and indirectly owns three run-of-river hydro-electric generating facilities. It directly owns the Serpent River Project (7 MW) and the Aux Sables Project (4 MW). It also holds a 99.99% limited partnership interest in Algonquin Power (Nagagami) Limited Partnership (“Algonquin LP”) which owns the Nagagami Project (19 MW). The remaining 0.01% of Algonquin LP is held by Algonquin Power General Partner (Nagagami) Inc. (“Algonquin GP”), which is 75% held by Algonquin Power Financial Services (Nagagami) Inc., which is a wholly owned subsidiary of Beaver Power. The balance of Algonquin GP is held by the Matawa First Nations Economic Development Corporation. Beaver Power and Algonquin LP are licensed generators pursuant respectively to licences EG-2002-0408 and EG-2006-0072.

Carmichael Limited Partnership (“Carmichael LP”)

The hydroelectric facility of Carmichael LP is located in northern Ontario. Carmichael LP directly owns Carmichael Falls, a 20 MW generating station on Groundhog River. Carmichael LP is held 99.99% by Great Lakes Power Trust, a wholly-owned subsidiary

of Great Lakes Hydro Income Fund, and 0.01% by its general partner, Carmichael GP Inc., which is also wholly-owned by Great Lakes Power Trust. Carmichael LP is a licensed generator pursuant to licence EG-2006-0070.

Brookfield Energy Marketing LP (“BEMLP”)

Brookfield Energy Marketing LP (“BEMLP”), located in Gatineau, Quebec, is a limited partnership which acts in the same capacity as BEMI. Brookfield Wind is its sole limited partner holding a 99.999% interest and BEMI is its general partner with a 0.001% interest. BEMLP is a licensed energy wholesale marketer under OEB licence EW-2005-0300.

Appendix B



Electricity Distribution Licence

ED-2009-0072

Great Lakes Power Distribution Inc.

Valid Until

May 4, 2029

Original signed by

Kirsten Walli

Board Secretary

Ontario Energy Board

Date of Issuance: May 5, 2009

Effective Date: Date the Commercial Transaction Closes (as defined in section 1 of this licence)

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
27th. Floor
Toronto, ON M4P 1E4

Commission de l'énergie de l'Ontario
C.P. 2319
2300, rue Yonge
27e étage
Toronto ON M4P 1E4

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Great Lakes Power Distribution Inc.
Electricity Distribution Licence ED-2009-0072

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1 Definitions

In this Licence:

"Accounting Procedures Handbook" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"Act" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"Affiliate Relationships Code for Electricity Distributors and Transmitters" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"commercial transaction" means the transfer of ownership of all of Great Lakes Power Limited's distribution facilities and any related assets, rights and obligations in respect of its distribution business to Great Lakes Power Distribution Inc.;

"distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"Distribution System Code" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"Electricity Act" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"Licensee" means Great Lakes Power Distribution Inc.;

"Market Rules" means the rules made under section 32 of the Electricity Act;

"Performance Standards" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"Rate Order" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"regulation" means a regulation made under the Act or the Electricity Act;

"Retail Settlement Code" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"service area" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"Standard Supply Service Code" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"wholesaler" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

- 2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

- 3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:
- a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;
 - b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and
 - c) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

- 4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.
- 4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

- 5.1 The Licensee shall at all times comply with the following Codes (collectively the "Codes") approved by the Board, except where the Licensee has been specifically exempted from such

compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

- a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;
- b) the Distribution System Code;
- c) the Retail Settlement Code; and
- d) the Standard Supply Service Code.

5.2 The Licensee shall:

- a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and
- b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

- 6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee's distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

- a) the building lies along any of the lines of the distributor's distribution system; and
- b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

- a) the building is within the Licensee's service area as described in Schedule 1; and
- b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

- 8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

- 9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

- 10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

- 11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

- 12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

- 13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.
- 13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

- 14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.
- 14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

- 15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.
- 15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:
- a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;
 - b) for billing, settlement or market operations purposes;
 - c) for law enforcement purposes; or
 - d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.
- 15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.
- 15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.
- 15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

- 16.1 The Licensee shall:
- a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;
 - b) publish information which will make its customers aware of and help them to use its dispute resolution process;
 - c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;
 - d) give or send free of charge a copy of the process to any person who reasonably requests it; and
 - e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

- 17.1 This Licence shall take effect on May 5, 2009 and expire on May 4, 2029. The term of this Licence may be extended by the Board.

18 Fees and Assessments

- 18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

- 19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.
- 19.2 All official communication relating to this Licence shall be in writing.
- 19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:
- a) when delivered in person to the addressee by hand, by registered mail or by courier;
 - b) ten (10) business days after the date of posting if the communication is sent by regular mail; and
 - c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

- 20.1 The Licensee shall:
- a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and
 - b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

1. The Licensee is licensed in respect to the geographic area comprised of the following list of townships:

Memaskwosh	Wishart	Miskokomon
Alanen	Herrick	Dulhut
Charbonneau	Tilley	Nebon
Dahl	Marne	Laronde
Dumas	Havilland	Redsky
Finan	Shields	Allouez
Riggs	Kars	Stone
Rennie	Vankoughnet	Alaire
Keating	Hodgins	Barager
Knicely		Bray
Leclaire	Aweres	Broome
Aguonie	Anderson	Goodwillie
Bruyere		Grootenboer
Legarde Add'l	Garden River Reserve IR14	Labonte
Levesque	Chesley Add'l	Peever
Menzies	Aberdeen	Raaflaub
Corbiere		Smilsky
Debassige	Tarbutt & Tarbutt Add'l	Tronsen
Echum	Plummer Add'l	Nicolet
Warpula	Rose	Olsen
Michipicoten	St. Joseph	Palmer
Fiddler	Jocelyn	Brule
Keesickquayash	Ashley	Fisher
Groseilliers	Chapais	Archibald
Bostwick	Dambrossio	Ley
Lastheels		Tupper
Michano	Jacobson	Gaudette
Nadjiwon	West	Fenwick
Rabazo	Stover	Deroche
Nebonaionquet	Killins	Whitman

Peterson	Lalibert	Pennefather
Restoule	Abotossaway	Jarvis
Tiernan	Bird	Chesley
Stoney	Copenace	Noganosh
Asselin	Legarde	Pawlis
Barnes	Macaskill	Quill
Brimacombe	Musquash	Giles
Bullock	Cowie	Rix
Greenwood	Dolson	Duncan
Labelle	St. Germain	Kehoe
Larson	Andre	MacDonald, Meredith & Aberdeen Add'l
Home	Esquega	Galbraith
Slater	Isaac	Laird
Tolmonen	Laforme	Johnson
Kincaid	Franchere	
Norberg	Michipicoten	Hilton
Ryan	Maness	Morin

2. Concessions 3, 4 and 5 of the Township of Dennis;
3. Approximately forty (40) square kilometres at the western limit of the former Township of Thessalon;
4. 5 rural customers in Kirkwood Township supplied off two short line taps into the Township;
5. Plus the following locations within the City of Sault Ste. Marie:
 - (a) 45 Third Line West as at March 14, 2003, excluding those areas of land within 45 Third Line West that are serviced by PUC Distribution Inc. (PUC) as identified in PUC's distribution licence, those being:
 - the areas of land on which the facilities on the northeast corner of 45 Third Line West are located, namely the "gatehouse" and "office";
 - (b) 77 Third Line West as at July 9, 2004;
 - (c) 3 Sackville Road;
 - (d) 150 Conmee Avenue;
 - (e) 429 Hudson Street, excluding those areas within 429 Hudson Street that are serviced by PUC as identified in PUC's distribution licence, those being:

- (i) the area of land on which the facility near the northwest corner of Hudson Street and Wellington Street West is located, namely the "yard office";
 - (ii) the area of land on which the facility near the junction of Hudson Street and St. George Avenue West is located, namely the "skimmer shack";
and
 - (iii) the area of land on which the railroad crossing signals are located, near the junction of Hudson Street and St. Andrew Terrace; and
- (g) 2 Sackville Road.

The service area excludes the following locations west of Thessalon on the north side of Hwy.17 which are supplied by Hydro One Networks Inc.:

- (a) 12564 Highway 17 West
- (b) 12600 Highway 17 West

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

The Licensee is exempt from the requirements of section 2.5.3 of the Standard Supply Service Code with respect to the price for small volume/residential consumers, subject to the Licensee offering an equal billing plan as described in its application for exemption from Fixed Reference Price, and meeting all other undertakings and material representations contained in the application and the materials filed in connection with it

APPENDIX A

MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

- a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:
 - i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and
 - ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.
- b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:
 - i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and
 - ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.
- c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity

consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

- a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;
- b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and
- c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

“embedded distributor” means a distributor who is not a market participant and to whom a host distributor distributes electricity;

“embedded generator” means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

“host distributor” means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

- a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:
 - i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and
 - ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.
- b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

- i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and
 - ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.
- c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

- a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;
- b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and
- c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

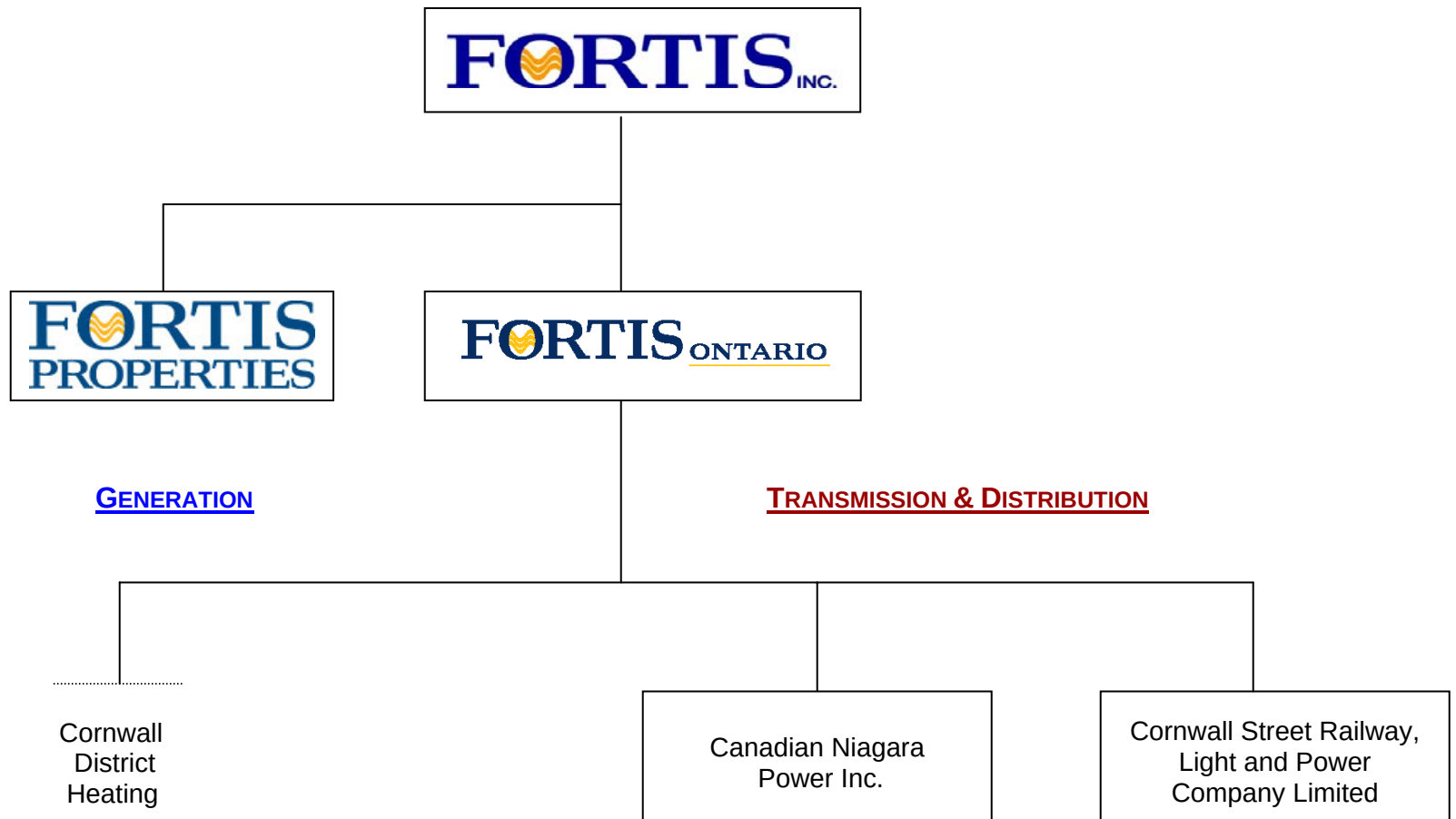
Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

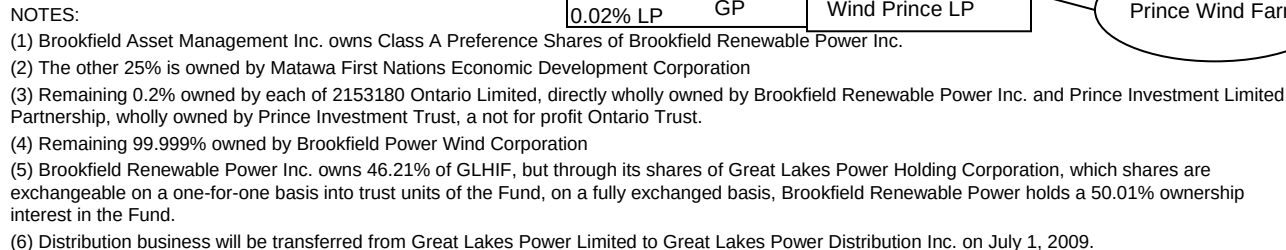
Appendix C

FORTISONTARIO INC. – CORPORATE CHART



June 25, 2009

ONTARIO OPERATIONS - CORPORATE STRUCTURE



Appendix D

Appendix D

Filed in confidence in accordance with
the Ontario Energy Board
Practice Direction on Confidential Filings

Appendix E

Financial Statements

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
December 31, 2007



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Canada

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Auditors' Report

To the Directors of
Great Lakes Power Limited

We have audited the balance sheet of Great Lakes Power Limited Distribution Division (the "Division") as at December 31, 2007 and the statements of capital account, operations and comprehensive loss, and cash flows for the year then ended. These financial statements are the responsibility of the Division's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Division as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants
March 14, 2008

Member of
Deloitte Touche Tohmatsu

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
BALANCE SHEET
As at December 31

<i>thousands of CDN dollars</i>	<i>Notes</i>	2007	2006
Assets			
Current assets			
Cash		\$ 100	\$ 1,215
Accounts and interest receivable	9	6,007	7,053
Due from related parties	5	1,781	657
Prepaid expenses and other		118	85
Materials and supplies		1,301	1,280
		9,307	10,290
Regulatory assets	9	1,265	1,266
Rate mitigation accrual	9, 12	13,690	11,070
Property, plant and equipment	6	57,503	52,467
		\$ 81,765	\$ 75,093
Liabilities and Capital Account			
Current liabilities			
Accounts and other payables		\$ 3,527	\$ 3,910
Taxes payable		4,474	4,356
		8,001	8,266
Due to related parties	5	19,313	12,394
Regulatory liabilities	9	767	560
Operating debt facility	5	12,000	12,000
Capital debt facility	5	20,500	20,500
		60,581	53,720
Capital account		21,184	21,373
		\$ 81,765	\$ 75,093

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
STATEMENT OF CAPITAL ACCOUNT
Year ended December 31

<i>thousands of CDN dollars</i>	2007	2006
Balance, beginning of year	\$ 21,373	\$ 21,630
Net loss	(189)	(257)
Balance, end of year	\$ 21,184	\$ 21,373

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
STATEMENT OF OPERATIONS AND COMPREHENSIVE LOSS
Year ended December 31

<i>thousands of CDN dollars</i>	Notes	2007	2006
Revenues		\$ 13,182	\$ 12,885
Operating expenses			
Operating and administration		4,768	4,881
Depreciation		3,559	3,465
Maintenance		3,368	2,871
Taxes, other than income taxes		320	348
		1,167	1,320
Expenses			
Interest, net	5	1,257	1,178
Loss on disposal of property, plant and equipment		22	155
Income taxes - current		77	244
		1,356	1,577
Net loss and comprehensive loss		\$ (189)	\$ (257)

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
STATEMENT OF CASH FLOWS
Year ended December 31

<i>thousands of CDN dollars</i>	Notes	2007	2006
Operating activities			
Net loss		\$ (189)	\$ (257)
Items not affecting cash			
Depreciation		3,559	3,465
Loss on disposal of property, plant and equipment		22	155
Net change in non-cash working capital and other	8	(10,884)	(3,681)
		(7,492)	(318)
Investing activities			
Due from related party		(1,150)	-
Additions to property, plant and equipment		(8,872)	(7,051)
		(10,022)	(7,051)
Financing activities			
Due to related parties		16,399	7,998
		16,399	7,998
Increase in cash		(1,115)	629
Cash, beginning of year		1,215	586
Cash, end of year		\$ 100	\$ 1,215
Supplementary Information			
Income taxes paid during the year		\$ -	\$ -

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007
(In thousands of CDN dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared on the basis that the Distribution Division (the "Division") of Great Lakes Power Limited operates as a separate legal entity. The Division is engaged in the distribution of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board (the "OEB"). These divisional statements have been prepared, for the purpose of complying with Section 2.1.6 of the Electricity Reporting and Record Keeping Requirements, in accordance with the accounting principles prescribed in the OEB Accounting Procedures Handbook (the "OEB Handbook") and, in circumstances where the OEB Handbook is not prescriptive, in accordance with Canadian generally accepted accounting principles. These financial statements do not include all of the assets, liabilities, revenues and expenses of Great Lakes Power Limited ("GLPL").

The following accounting policies have been applied in the preparation of these financial statements:

Property, plant and equipment

Property, plant and equipment are carried at cost, less accumulated depreciation. Depreciation has been calculated on the cost of the distribution assets on a straight-line basis at rates prescribed in the OEB Handbook as follows:

	Method	Rate
Buildings	Straight-line	5 to 50 years
Equipment	Straight-line	5 to 25 years
Distribution stations, towers and related fixtures	Straight-line	25 to 40 years

Impairment of long lived assets

The Division reviews long-lived assets for other than temporary impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. Should an asset be considered to be impaired, an impairment loss is recognized in an amount equal to the excess of the asset's carrying value over its fair value.

Pension and Employee Future Benefits

The cost of retirement benefits for the Division's defined benefit pension plan and post-employment benefits is recognized as the benefits are earned by employees. The Division uses the projected benefit method pro-rated on the length of service and management's best estimate assumptions to value its pension and other retirement benefits. Assets are valued at fair value for purposes of calculating the expected return on plan assets. Past service costs resulting from plan amendments are being amortized on a linear basis over the average remaining service period of active members expected to receive the benefits under the plan. Cumulative gains and losses in excess of 10% of the greater of the accrued benefit obligation and the market value of the plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan. The average remaining service lives under the defined benefit pension plan as at December 31, 2007 varies from 12.0 to 16.0 years (2006 - 12.0 to 16.5 years). The average remaining service

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007

(in thousands of CDN dollars)

life under the post-employment benefit plan as at December 31, 2007 is 17.0 years (2006 – 17.0 years).

Capitalization of Interest

Interest on funds used during construction is charged to construction work in progress at the prescribed rate of return applicable to the rate base.

Revenue recognition

Revenue from the delivery of electricity is recorded on a basis of cyclical billings and includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

Purchased power

Purchased power represents all pass through charges billed to the Division by the Independent Electricity System Operator ("IESO"). This expense is comprised of Energy, Transmission, and Wholesale Market Service charges.

Interest expense

Interest expense has been calculated using the approved rate order debt amounts and rates.

Income taxes

The Division's income taxes are calculated on a separate tax return basis. However, GLPL was managing its tax position for the benefit of its business as a whole, and its tax strategies are not necessarily reflective of the tax strategies that the Division would have followed as a stand-alone company.

Use of estimates

The preparation of financial statements in conformity with the accounting principles prescribed in the OEB handbook and Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses during the reporting period. During the years presented, management has made a number of estimates and valuation assumptions including accruals, depreciation, asset impairment and those relevant to the defined benefit pension plan. 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 estimates.

Rate Regulation

On January 1, 2005, the Division adopted CICA Handbook Accounting Guideline 19, "Disclosure by Entities Subject to Rate Regulation". The Division is regulated by the OEB. Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred costs will be recovered in the future, the Division may defer these costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007

(In thousands of CDN dollars)

future, the Division reports a regulatory liability. Also, if the regulation provides for lesser or greater planned revenue to be received or returned by the Division through future rates, the Division recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the relevant regulation.

2. CHANGES IN ACCOUNTING POLICIES

On January 1, 2007, the Division adopted the following new accounting standards for Canadian generally accepted accounting principles:

Handbook Section 1530, Comprehensive Income

This section establishes standards for reporting and presenting comprehensive income (loss), which is defined as the change in owners' equity from transactions and other events from non-owner sources. This standard requires certain gains and losses to be presented in other comprehensive income (loss) until it is considered appropriate to recognize such amounts into net income. Major components for this category 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. There was no impact on the adoption of this new standard on the Division's financial statements as at January 1, 2007.

Handbook Section 3251, Equity

The Division adopted Section 3251, Equity replacing Section 3250, Surplus. This section describes the presentation of equity and changes in equity for a reporting period as a result of the application of Section 1530, Comprehensive Income. There was no impact on the adoption of this new standard on the Division's financial statements as at January 1, 2007.

Handbook Section 3855, Financial Instruments – Recognition and Measurement

Under Section 3855, all financial instruments are classified as one of the following: held-for-trading, held-to-maturity investments, loans and receivables, other financial liabilities, or available-for-sale financial assets. Financial assets and liabilities held-for-trading are 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, are measured at amortized cost using the effective interest method of amortization. Available-for-sale financial instruments are measured at fair value with unrealized gains and losses recognized in other comprehensive income. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading. For other financial instruments, transaction costs are capitalized on initial recognition.

The Division has implemented the following classification:

- (a) Cash is designated as a financial asset held-for-trading and is measured at fair value through net income at each period end.
- (b) Accounts receivable, interest receivable and due from related parties are classified as loans and receivables. Accounts and other payables and due to related parties are classified as other financial liabilities. These accounts are measured at fair value at inception and are subsequently measured at amortized cost.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007

(In thousands of CDN dollars)

- (c) The operating and capital debt facilities are classified as other financial liabilities. After their initial fair value measurement, they are measured at amortized cost.

There was no material impact on the Division's financial statements as a result of the adoption of the above accounting standard.

3. FUTURE ACCOUNTING POLICY CHANGES

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, Capital Disclosures, Handbook Section 3862, Financial Instruments – Disclosures, and Handbook Section 3863, Financial Instruments – Presentation.

Section 1535 establishes standards for disclosing information about the Division's capital and how it is managed. The standard requires disclosures of the Division's objectives, policies and processes for managing capital, the quantitative data about what the Division regards as capital, whether the Division has complied with any capital requirements and if it has not complied, the consequences of such non-compliance.

The new sections 3862 and 3863 will replace Handbook Section 3861, Financial Instruments – Disclosure and Presentation by revising and enhancing disclosure requirements but carrying forward presentation requirements unchanged. They place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the Division manages those risks.

The Division does not expect the adoption of these new standards to have a material impact on the financial statements.

4. INCOME TAXES

The Division's future income tax liability of \$843 (2006 - \$1,183) as at December 31, 2007 and the Division's future income tax recovery of \$356 (2006 - recovery \$318) for the year ended December 31, 2007 have not been recorded in the financial statements. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time. As these financial statements report the results for the Division, the amounts presented for current income taxes represent the amounts that would be payable if the Division was a separate corporate entity.

5. RELATED PARTY TRANSACTIONS

- (a) The Division has provided advances to and received advances from entities under common control and other divisions of GLPL in the normal course of operations. These advances are non-interest bearing and unsecured. It is management's understanding that the advances due to related parties will not come due during the following year.
- (b) In the normal course of operations, Riskcorp Inc., a broker company affiliated with Brookfield Asset Management Inc., GLPL's ultimate parent, entered into transactions with GLPL to provide insurance. These transactions have been measured at exchange value. The total cost allocated

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007
(in thousands of CDN dollars)

to the Division in 2007 for these services was \$111 (2006 - \$107) and no amount remains outstanding at year end (2006 - \$nil).

- (c) Operating debt facility in the amount of \$12,000 (2006 - \$12,000) represents funds due to another division of GLPL and is non-interest bearing, unsecured and due on demand. It is management's expectation that this loan will not come due during the following year.
- (d) Capital debt facility in the amount of \$20,500 (2006 - \$20,500) represents the amount of debt permitted under the application with the OEB, as adjusted, to be allocated to fund the ownership of property, plant and equipment and is unsecured. These funds are due to another division of GLPL. Interest charged to Income on these funds is prescribed by regulation in the amount of 6.25% (2006 - 6.25%). Net interest expense on the capital debt facility during the year was as follows:

	2007	2006
Interest expense incurred	\$ 1,295	\$ 1,293
Capitalized interest	(38)	(115)
	\$ 1,257	\$ 1,178

- (e) As a result, the following balances are receivable (payable) at December 31:

	2007	2006
Advances to other divisions of GLPL	\$ 1,298	\$ 158
Advances to entities under common control	483	499
	\$ 1,781	\$ 657
Advances from other divisions of GLPL	\$ (19,285)	\$ (12,394)
Advances from entities under common control	(28)	-
	\$ (19,313)	\$ (12,394)

6. PROPERTY, PLANT AND EQUIPMENT

			2007	2006
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Land	\$ 842	\$ -	\$ 842	\$ 842
Buildings	7,236	2,201	5,035	5,157
Equipment	22,245	13,943	8,302	515
Distribution stations, towers and related fixtures	71,846	29,336	42,510	45,531
Capital work in progress	814	-	814	422
	\$ 102,983	\$ 45,480	\$ 57,503	\$ 52,467

Cost and accumulated depreciation as at December 31, 2006 were \$94,921 and \$42,454, respectively.

Throughout the year the Division disposed of assets for total net proceeds of \$nil, resulting in a loss on disposal of \$22.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007

(in thousands of CDN dollars)

7. PENSION AND EMPLOYEE FUTURE BENEFITS

GLPL maintains a multiemployer registered defined benefit, final pay pension plan and an unfunded non-pension benefit plan (the "Plans") for all of its employees. The non-pension plan includes benefits such as health and dental care, retirement bonuses and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial valuations. The benefit plan contribution allocated to the Division for 2007 was \$946 (2006 - \$783). The investment rate of return was 6.75% (2006 - 7.00%). The discount rate used was 5.25% (2006 - 5.00%) with a rate of compensation increase of 3.50% (2006 - 3.50%).

GLPL also offers a defined contribution pension plan to certain employees. GLPL contributes amounts based on the level of employee contributions for this plan.

The defined benefit pension plan and post employment benefits information provided in the following table relates to the consolidated financial statements of GLPL.

	2007		2006	
	Defined Benefit Pension Plan	Non-Pension Benefits Plan	Defined Benefit Pension Plan ¹	Non-Pension Benefits Plan
Weighted average assumptions				
Benefit obligation				
Discount rate	5.50%	5.50%	5.25%	5.25%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%
Initial health care trend rate	-	5.91%	-	6.47%
Ultimate trend rate	-	4.27%	-	4.24%
Year ultimate rate reached	-	2016	-	2016
Benefit expense				
Discount rate	5.25%	5.25%	5.00%	5.00%
Long-term rate of return on plan assets	6.75%	-	7.00%	-
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%
Initial health care trend rate	-	6.47%	-	6.69%
Ultimate trend rate	-	4.24%	-	4.24%
Year ultimate rate reached	-	2016	-	2016
Accrued benefit obligations				
Balance, beginning of year	\$ 49,771	\$ 7,598	\$ 46,974	\$ 11,890
Current service cost	979	304	947	280
Interest cost	2,700	435	2,362	384
Employee contributions	381	-	372	-
Net benefit payments	(2,521)	(261)	(1,943)	(234)
Actuarial (gain) loss	(308)	147	(1,627)	(4,722)
Balance, end of year	\$ 51,002	\$ 8,223	\$ 47,085	\$ 7,598

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION **NOTES TO THE FINANCIAL STATEMENTS**

December 31, 2007
(In thousands of CDN dollars)

	2007		2006	
	Defined Benefit Pension Plan	Non-Pension Benefits Plan	Defined Benefit Pension Plan ¹	Non-Pension Benefits Plan
Fair value plan assets				
Balance, beginning of year	\$ 47,976	\$ -	\$ 43,550	\$ -
Employer contributions	2,398	261	1,583	234
Employee contributions	381	-	372	-
Actual return on plan assets	2,041	-	4,414	-
Benefits paid	(2,521)	(261)	(1,943)	(234)
Balance, end of year	\$ 50,275	\$ -	\$ 47,976	\$ -
Reconciliation of accrued benefit liability				
Plan (deficit) surplus	\$ (727)	\$ (8,223)	\$ 890	\$ (7,598)
Unamortized transitional obligation	3,342	3,989	1,549	4,487
Unamortized net actuarial loss (gain)	2,567	(1,421)	1,411	(1,583)
Valuation allowance	(252)	-	(227)	-
Accrued benefit asset (liability)	\$ 4,930	\$ (5,655)	\$ 3,623	\$ (4,694)
Expense				
Current service costs	\$ 979	\$ 304	\$ 947	\$ 280
Interest cost	2,700	435	2,362	384
Actual return on plan assets	(2,041)	-	(4,414)	-
Actuarial (gain) loss	(308)	147	(1,627)	(4,722)
Costs arising in the year	1,330	886	(2,732)	(4,058)
Differences between costs arising in the period and costs recognized in the period in respect of:				
Actuarial (gain) loss	308	(162)	1,627	4,691
Return on plan assets	(1,206)	-	1,367	-
Transitional obligation	520	499	310	499
Increase in valuation allowance provided against accrued benefit asset	26	-	227	-
Net expense	\$ 978	\$ 1,223	\$ 799	\$ 1,132

¹ The fiscal year ended December 31, 2006 figures did not include the GLPL Supplemental Plan. If this was included, the deficit would increase by \$2,685, unamortized transitional obligation would increase by \$2,313, the unamortized net actuarial loss would increase by \$258, and the accrued benefit asset would decrease by \$114.

The accrued benefit liability allocated to the Division as at December 31, 2007 and 2006 is \$280 and \$153, respectively and has been recorded in accounts and other payables.

In 2007, the total employer expense for the Division's defined contribution pension plan was \$128 (2006 - \$132).

Actuarial valuations

Actuarial valuations for these plans are required every three years. The most recent actuarial valuations for the pension and non-pension benefit plans ranged from June 1, 2006 to December 31, 2006. GLPL measures its accrued benefit obligations and the fair value of plan assets for

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007
(in thousands of CDN dollars)

accounting purposes as at December 31 of each year. The valuations include an indexation of pension payments of 2.00% per year (2006 – 2.00% per year). GLPL may choose to perform valuations for these plans prior to the earliest required dates.

Sensitivity analysis

GLPL's sensitivity in the non-pension benefit plan to a 1% change in the health care cost trend rate, for the year ended December 31, 2007, is summarized as follows:

	Benefit Obligation	Benefit Expense
Impact of a 1% increase in health care cost trend rate	\$ 1,761	\$ 205
Impact of a 1% decrease in health care cost trend rate	\$ (1,350)	\$ (150)

Asset category

GLPL's defined benefit pension plan asset allocations at December 31, by asset category are as follows:

	2007	2006
Equity securities	60%	60%
Debt securities	40%	40%
Total	100%	100%

Cash payments

All employer contributions were fully paid during the year and as such, no balance owing remains outstanding as at year-end.

8. STATEMENT OF CASH FLOWS

The change in non-cash working capital is comprised of the following:

	2007	2006
Accounts and interest receivable	\$ 1,046	\$ (621)
Due from related parties	26	(678)
Prepaid expenses and other	(33)	6
Materials and supplies	(21)	(213)
Long-term portion of rate mitigation accrual	(2,620)	(2,584)
Accounts and other payables	(128)	1,553
Due to related parties	(9,480)	-
Taxes payable	118	330
Regulatory assets and liabilities (net)	208	(1,474)
	\$ (10,884)	\$ (3,681)

Capital asset additions totaling \$773 which were included in accruals at December 31, 2006, have been included in the statement of cash flows for 2007, as they resulted in a cash outflow during the year. Similarly, capital asset additions totaling \$518 included in accruals at December 31,

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007
(in thousands of CDN dollars)

2007, have been excluded from the statement of cash flows for 2007, as they did not result in a cash outflow during the year.

9. EFFECTS OF RATE REGULATION

The Division operates in accordance with the regulations of the OEB. Regulatory assets and liabilities represent certain revenues earned or costs incurred in the current year or in prior years that have been or are expected to be recovered from customers upon approval from the OEB. In the absence of rate regulation, these balances would have been recorded as revenues or expenses in the statement of operations and other comprehensive loss.

The recovery period for these regulatory accounts is not determinable until the application filed by the Division on August 31, 2007 is approved by the OEB. The OEB has guaranteed approval of the variance accounts as per Article 490 of the Accounting Procedures Handbook.

a) The Division recorded the following regulatory assets and liabilities as at December 31:

	2007	2006
<i>Regulatory assets</i>		
OEB variance accounts	\$ 1,109	\$ 1,110
OEB cost assessment fees	156	156
	\$ 1,265	\$ 1,266
<i>Regulatory liabilities</i>		
Transition costs recovery	\$ 767	\$ 560
	\$ 767	\$ 560

OEB variance accounts

As prescribed by regulatory order, OEB variance accounts are used to record the net amounts charged by the IESO and the amount billed to customers, resulting in a regulatory asset or liability. These balances will be recovered or refunded through rates as approved by the OEB.

OEB cost assessment fees

As prescribed by regulatory order, this regulatory account relates to the recovery of cost assessment fees in 2004 and 2005. The recovery period for this balance is unknown at this time. This balance has been included with the 2007 rate application and upon approval, a recovery period will be determined. The risk of non-approval of this balance is negligible because this balance has been recorded as a regulatory asset as prescribed by regulatory order.

Transition costs recovery

As prescribed by regulatory order, this regulatory account relates to the recovery of certain allowed transition costs based on the OEB interim regulatory asset recovery order. During 2007, \$207 (2006 - \$295) was recovered relating to this account through rates. Upon approval from the OEB, this balance will be netted against property, plant and equipment.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007

(in thousands of CAD dollars)

b) Rate mitigation accrual

The rate mitigation accrual relates to the return on equity portion of the revenue requirement from the 2002 rate application to the OEB. Distribution revenue in the amount of \$14,436 (2006 - \$11,927) has been accrued in accordance with the mitigation strategy submitted with the 2002 rate application, with the current portion in the amount \$1,066 (2006 - \$1,066) recorded in accounts and interest receivable. In 2007, \$320 (2006 - \$209) was included in the rate mitigation accrual relating to the cash shortfall that will be collected in future years due to the re-classification of customers to a class with a lower rate, as per the direction from the OEB. The application to the OEB to collect the accrual balance as at December 31, 2003 in the amount of \$4,053 has been approved and as of December 31, 2007, \$2,429 has been collected (2006 - \$1,470). On August 31, 2007, management filed an application to the OEB to continue recovery of its rate mitigation accrual balance up to the date the proposed rates become effective. This revenue has been accrued on the basis that it is collectible through future rates. Management assesses the collectibility of this amount periodically. Collectibility of this balance is supported by the fact that the OEB has approved the rate mitigation accrual at December 31, 2003 and therefore, management believes that the current balances will be approved by the OEB upon submission of the respective applications.

The methodology relating to the calculation of the rate mitigation accrual has been revised (change in accounting estimate). Refer to note 12 for more information.

c) Customer reclassification accrual

The customer reclassification accrual relates to a deficiency arising from the reclassification of one of the Division's customers. As prescribed by regulatory order (RP-2005-0013, EB-2005-0031), the Division is to record the deficiency and apply for recovery at a future date. In accordance with this order, distribution revenue in the amount of \$320 (2006 - \$209) has been recorded as part of the rate mitigation accrual.

10. FINANCIAL INSTRUMENTS

a) Fair value

The carrying amounts in the balance sheet of accounts and interest receivable, due from related parties, accounts and other payables, and taxes payable approximate their fair values, reflecting their short maturities.

The fair values of the operating and capital debt facilities with GLPL Investment Division and the amounts due to related parties are not determinable by management due to the related party nature of the balances.

b) Interest rate risk

The Division's capital debt facility debt bears interest at a rate set periodically by the OEB. Consequently, there is cash flow exposure.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007
(In thousands of CDN dollars)

c) 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 Division would incur a loss in replacing the defaulted transaction. The Division's financial instruments that are potentially exposed to credit risks are accounts and interest receivable. The Division 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 continually monitors these exposures.

These risks are reviewed on a regular basis and the Division believes the exposures are manageable and not material in relation to its overall business operations.

11. COMMITMENTS, CONTINGENCIES AND GUARANTEES

In the normal course of operations, the Division executes agreements that provide for indemnification and guarantees to third parties in transactions such as debt issuances. The nature of substantially all of the indemnification undertakings prevents the Division from making a reasonable estimate of the maximum potential amount the Division could be required to pay third parties as the agreements do not 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, the Division has not made significant payments under such indemnification agreements.

The Division may, from time to time, be involved in legal proceedings, claims, and litigation that arise in the ordinary course of business which the Division believes would not reasonably be expected to have a material adverse effect on the financial condition of the Division.

The Division has asset retirement obligations associated with its property, plant and equipment. The retirement date for these assets cannot be reasonably estimated and therefore the fair value of the associated liability cannot be estimated at this time. As a result, no liability has been accrued in these financial statements.

12. CHANGE IN ACCOUNTING ESTIMATE

The Division records the rate mitigation accrual using management's best estimate based on the latest available, reliable information. During 2007, management revised the methodology for recording the rate mitigation accrual to record a fixed annual amount, which places all volume variance risk on the Division. This method of estimation is generally accepted by the OEB.

The change in the accounting estimate for the recording of the rate mitigation accrual resulted in a change in the amount of the accrual recorded on the balance sheet during the year. The net effect of the difference of the change in estimate for the recording of the rate mitigation accrual for the current year is:

Accrual balance with revised estimate as of December 31, 2007	Balance with previous estimate as of December 31, 2007	Net effect
\$ 14,436	\$ 14,358	\$ (78)

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION NOTES TO THE FINANCIAL STATEMENTS

December 31, 2007
(in thousands of CDN dollars)

It is impracticable to estimate the net effect of the change in the accounting estimate on the future periods due to the outstanding rate application with the OEB.

Financial Statements

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

December 31, 2008



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Auditors' Report

To the Directors of
Great Lakes Power Limited

We have audited the balance sheet of Great Lakes Power Limited Distribution Division (the "Division") as at December 31, 2008 and the statements of capital account, operations and comprehensive income (loss), and cash flows for the year then ended. These financial statements are the responsibility of the Division's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Division as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Licensed Public Accountants

Toronto, Canada
April 27, 2009

Member of
Deloitte Touche Tohmatsu

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
BALANCE SHEET
As at December 31

<i>thousands of CDN dollars</i>	<i>Notes</i>	2008	2007
Assets			
Current assets			
Cash		\$ 100	\$ 100
Accounts and interest receivable		12,655	6,007
Due from related parties	5	10,114	1,781
Prepaid expenses and other		114	118
Materials and supplies		1,340	1,301
		24,323	9,307
Regulatory assets	9	2,107	1,265
Rate mitigation accrual	9	14,890	13,690
Property, plant and equipment	6	64,893	57,503
		\$ 106,213	\$ 81,765
Liabilities and Capital Account			
Current liabilities			
Accounts and other payables		\$ 5,499	\$ 3,527
Taxes payable		1,742	4,474
		7,241	8,001
Due to related parties	5	40,831	19,313
Regulatory liabilities	9	1,009	767
Operating debt facility	5	12,000	12,000
Capital debt facility	5	20,500	20,500
		81,581	60,581
Capital account		24,632	21,184
		\$ 106,213	\$ 81,765

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION **STATEMENT OF CAPITAL ACCOUNT**

Year ended December 31

<i>thousands of CDN dollars</i>	2008	2007
Balance, beginning of year	\$ 21,184	\$ 21,373
Net income (loss)	3,448	(189)
Balance, end of year	\$ 24,632	\$ 21,184

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
STATEMENT OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)
Year ended December 31

<i>thousands of CDN dollars</i>	Notes	2008	2007
Revenues		\$ 18,605	\$ 13,182
Operating expenses			
Operating and administration		5,594	4,768
Depreciation		3,728	3,559
Maintenance		2,984	3,368
Taxes, other than income taxes		45	320
		6,254	1,167
Expenses			
Interest, net	5	1,088	1,257
Loss on disposal of property, plant and equipment		19	22
Other income		(43)	-
Income taxes - current		1,742	77
		2,806	1,356
Net income (loss) and comprehensive income (loss)		\$ 3,448	\$ (189)

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION
STATEMENT OF CASH FLOWS
Year ended December 31

<i>thousands of CDN dollars</i>	Notes	2008	2007
Operating activities			
Net income (loss)		\$ 3,448	\$ (189)
Items not affecting cash			
Depreciation		3,728	3,559
Loss on disposal of property, plant and equipment		19	22
Net change in non-cash working capital and other	8	(3,506)	(10,884)
		3,689	(7,492)
Investing activities			
Due from related party		(8,333)	(1,150)
Additions to property, plant and equipment		(11,119)	(8,872)
		(19,452)	(10,022)
Financing activities			
Due to related parties		15,763	16,399
		15,763	16,399
Increase in cash		-	(1,115)
Cash, beginning of year		100	1,215
Cash, end of year		\$ 100	\$ 100
Supplementary information			
Income taxes paid during the year		\$ -	\$ -

See accompanying notes to the financial statements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008
(in thousands of CDN dollars)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared on the basis that the Distribution Division (the "Division") of Great Lakes Power Limited ("GLPL") operates as a separate legal entity. The Division is engaged in the distribution of electricity to the area adjacent to Sault Ste. Marie, Canada and is subject to the regulations of the Ontario Energy Board (the "OEB"). These divisional financial statements have been prepared, for the purpose of complying with Section 2.1.6 of the Electricity Reporting and Record Keeping Requirements, in accordance with the accounting principles prescribed in the OEB Accounting Procedures Handbook (the "OEB Handbook") which are consistent with Canadian generally accepted accounting principles. These financial statements do not include all of the assets, liabilities, revenues and expenses of Great Lakes Power Limited ("GLPL").

These financial statements have been derived from the consolidated financial statements and accounting records of GLPL using historical results of operations and historical basis of assets and liabilities of the Division. Management believes the assumptions underlying the financial statements are reasonable. However, the financial statements included herein may not necessarily reflect the results of operations, financial position and cash flows of the Division had it been a stand-alone entity during the years presented. The Division's income taxes are calculated on a separate tax return basis. However, GLPL manages its tax position for the benefit of its business as a whole, and its tax strategies are not necessarily reflective of the tax strategies that the Division would have followed as a stand-alone entity.

The following accounting policies have been applied in the preparation of these financial statements:

Property, plant and equipment

Property, plant and equipment are carried at cost, less accumulated depreciation. Depreciation has been calculated on the cost of the distribution assets on a straight-line basis at rates prescribed in the OEB Handbook as follows:

	Method	Rate
Buildings	Straight-line	5 to 50 years
Equipment	Straight-line	5 to 25 years
Distribution stations, towers and related fixtures	Straight-line	25 to 40 years

Construction work in progress is not depreciated until the assets are put into service.

Impairment of long lived assets

The Division reviews long-lived assets for other than temporary impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. Should an asset be considered to be impaired, an impairment loss is recognized in an amount equal to the excess of the asset's carrying value over its fair value.

Pension and Employee Future Benefits

The cost of retirement benefits for the Division's defined benefit pension plan and post-employment benefits is recognized as the benefits are earned by employees. The Division uses the projected benefit method pro-rated on the length of service and management's best estimate assumptions to value its pension and other retirement benefits. Assets are valued at fair value for purposes of

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

calculating the expected return on plan assets. Past service costs resulting from plan amendments are being amortized on a linear basis over the average remaining service period of active members expected to receive the benefits under the plan. Cumulative gains and losses in excess of 10% of the greater of the accrued benefit obligation and the market value of the plan assets are amortized over the average remaining service period of active members expected to receive benefits under the plan. The average remaining service lives under the defined benefit pension plan as at December 31, 2008 varies from 12.0 to 16.0 years (2007 – 12.0 to 16.0 years). The average remaining service life under the post-employment benefit plan as at December 31, 2008 is 16.0 years (2007 – 17.0 years).

Capitalization of interest

Interest on funds used during construction is charged to construction work in progress at the prescribed rate of return applicable to the rate base.

Revenue recognition

Revenue from the delivery of electricity is recorded on a basis of cyclical billings and includes unbilled revenue accrued in respect of electricity delivered but not yet billed.

Purchased power

Purchased power represents all pass through charges billed to the Division by the Independent Electricity System Operator ("IESO"). This expense is comprised of Energy, Transmission, and Wholesale Market Service charges.

Interest expense

Interest expense has been calculated on an intercompany debt amount using an interest rate prescribed by regulation.

Income taxes

The Division's income taxes are calculated on a separate tax return basis. However, GLPL was managing its tax position for the benefit of its business as a whole, and its tax strategies are not necessarily reflective of the tax strategies that the Division would have followed as a stand-alone company.

Use of estimates

The preparation of financial statements in conformity with the accounting principles prescribed in the OEB handbook and Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities, and the reported amounts of revenues and expenses during the reporting period. During the years presented, management has made a number of estimates and valuation assumptions including accruals, depreciation, asset impairment and those relevant to the defined benefit pension plan. 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 estimates.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

Rate Regulation

On January 1, 2005, the Division adopted CICA Handbook Accounting Guideline 19, "Disclosure by Entities Subject to Rate Regulation". The Division is regulated by the OEB. Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred costs will be recovered in the future, the Division may defer these costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, the Division reports a regulatory liability. Also, if the regulation provides for lesser or greater planned revenue to be received or returned by the Division through future rates, the Division recognizes and reports a regulatory asset or liability, respectively. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the relevant regulation.

2. CHANGES IN ACCOUNTING POLICIES

On January 1, 2008, the Division adopted the following new accounting standards for Canadian generally accepted accounting principles:

Handbook Section 1535 – Capital Disclosures

Section 1535 establishes standards for disclosing information about the Division's capital and how it is managed. The standard requires disclosures of the Division's objectives, policies and processes for managing capital, the quantitative data about what the Division regards as capital, whether the Division has complied with any capital requirements and if it has not complied, the consequences of such non-compliance. Refer to Note 11 for disclosure on Capital Management.

Handbook Section 3862, Financial Instruments – Disclosures, and Handbook Section 3863, Financial Instruments – Presentation

The new sections 3862 and 3863 will replace Handbook Section 3861, Financial Instruments – Disclosure and Presentation by revising and enhancing disclosure requirements but carrying forward presentation requirements unchanged. They place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the Division manages those risks. Refer to Note 12 for disclosure on Financial Instruments and Risk Management.

Handbook Section 3031 – Inventories

The new section 3031 will replace Handbook Section 3030. Under this new standard, inventories are required to be measured at the lower of cost and net realizable value and any items considered to be major future components of property, plant and equipment are to be transferred to property, plant and equipment. The new standard also provides updated guidance on the appropriate methods of determining cost and the impact of any write-downs to net realizable value. The implementation of this standard did not have a significant impact on the Division's financial statements.

3. FUTURE ACCOUNTING POLICY CHANGES

Goodwill and Intangible Assets – Handbook Section 3064

In February 2008, the CICA issued Handbook Section 3064, Goodwill and Intangible Assets, replacing Handbook Sections 3062, Goodwill and Other Intangible Assets and 3450, Research and Development Costs. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill and intangibles by profit-oriented enterprises. The new section will be

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

applicable to the Division's financial statements beginning January 1, 2009. The Division is currently evaluating the impact of this pronouncement on its financial statements.

Rate Regulated Enterprises

During 2007, the Accounting Standards Board ("AcSB") issued an exposure draft proposing to remove all specific references to rate regulated accounting from the CICA Handbook. In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100 "Generally Accepted Accounting Principles", retain existing references to rate regulated accounting in the CICA Handbook, amend CICA Handbook Section 3465 "Income Taxes" to require the recognition of future income tax liabilities and assets as well as a corresponding regulatory asset or liability, and retain existing requirements to disclose the effects of rate regulation per AcG-19. The new rules will apply retrospectively to annual financial statements relating to fiscal years beginning on or after January 1, 2009.

Currently, the Division uses the taxes payable method of accounting for income taxes. The estimated effect of adopting these changes on December 31, 2008 would be to record a future income tax liability of \$651. Refer to note 4 for further information.

4. INCOME TAXES

The Division's future income tax liability of \$651 (2007 - \$843) as at December 31, 2008 and the Division's future income tax recovery of \$192 (2007 - recovery \$356) for the year ended December 31, 2008 have not been recorded in the financial statements. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of the regulated business at that time. As these financial statements report the results for the Division, the amounts presented for current income taxes represent the amounts that would be payable if the Division was a separate corporate entity.

5. RELATED PARTY TRANSACTIONS

- (a) The Division has provided advances to and received advances from entities under common control and other divisions of GLPL in the normal course of operations. These advances are non-interest bearing and unsecured. It is management's expectation that the advances due to related parties will not come due during the following year.
- (b) In the normal course of operations, Riskcorp Inc., a broker company affiliated with Brookfield Asset Management Inc., GLPL's ultimate parent, entered into transactions with GLPL to provide insurance. These transactions have been measured at exchange value. The total cost allocated to the Division in 2008 for these services was \$105 (2007 - \$111) and no amount remains outstanding at year end (2007 - \$nil).
- (c) Operating debt facility in the amount of \$12,000 (2007 - \$12,000) represents funds due to another division of GLPL and is non-interest bearing, unsecured and due on demand. It is management's expectation that this loan will not come due during the following year.
- (d) Capital debt facility in the amount of \$20,500 (2007 - \$20,500) represents the amount of debt permitted under the application with the OEB, as adjusted, to be allocated to fund the ownership of property, plant and equipment, and is unsecured. These funds are due to another division of GLPL. Interest charged to income on these funds is at a rate of 6.25% (2007 - 6.25%). Net interest expense on the capital debt facility during the year was as follows:

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

	2008	2007
Interest expense incurred	\$ 1,281	\$ 1,295
Regulatory carrying charge offset	(117)	-
Capitalized interest	(76)	(38)
	\$ 1,088	\$ 1,257

(e) In accordance with an OM&A agreement that exists between the Division and Great Lakes Power Transmission Limited Partnership ("GLPTLP"), a related party through common control, GLPTLP's transmission assets are operated by the Division, and all costs are passed on to GLPTLP. The Division is responsible for all operating, maintenance, administrative, and capital activity, the cost of which is tracked and billed to GLPTLP with no mark-up.

(f) As a result, the following balances are receivable (payable) at December 31:

	2008	2007
Advances to other divisions of GLPL	\$ 7,151	\$ 1,298
Costs incurred by the Division on behalf of GLPTLP	2,471	-
Advances to entities under common control	492	483
	\$ 10,114	\$ 1,781
Advances from other divisions of GLPL	\$ (40,724)	\$ (19,285)
Advances from entities under common control	(107)	(28)
	\$ (40,831)	\$ (19,313)

6. PROPERTY, PLANT AND EQUIPMENT

			2008	2007
	Cost	Accumulated Depreciation	Net Book Value	Net Book Value
Land	\$ 842	\$ -	\$ 842	\$ 842
Buildings	7,537	2,360	5,177	5,035
Equipment	23,474	14,848	8,626	8,302
Distribution stations, towers and related fixtures	79,139	31,754	47,385	42,510
Capital work in progress	2,863	-	2,863	814
	\$ 113,855	\$ 48,962	\$ 64,893	\$ 57,503

Cost and accumulated depreciation as at December 31, 2007 were \$102,983 and \$45,480, respectively.

Throughout the year the Division disposed of assets for total net proceeds of \$nil (2007 - \$nil), resulting in a loss on disposal of \$19 (2007 - \$22).

7. PENSION AND EMPLOYEE FUTURE BENEFITS

The Division is part of a multiemployer registered defined benefit, final pay pension plan and an unfunded non-pension benefit plan (the "Plans"), both provided by GLPL. The non-pension plan includes benefits such as health and dental care, retirement bonuses and life insurance. The obligation under these plans is determined periodically through the preparation of actuarial

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION **NOTES TO THE FINANCIAL STATEMENTS**

December 31, 2008

(in thousands of CDN dollars)

valuations. The benefit plan contribution allocated to the Division for 2008 was \$914 (2007 - \$946). The investment rate of return was 6.75% (2007 - 6.75%). The discount rate used was 5.50% (2007 - 5.25%) with a rate of compensation increase of 3.50% (2007 - 3.50%).

The Division also participates in a defined contribution pension plan provided by GLPL to certain employees. GLPL contributes amounts based on the level of employee contributions for this plan.

The defined benefit pension plan and post employment benefits information provided in the following table relates to the consolidated financial statements of GLPL.

	2008		2007	
	Defined Benefit Pension Plan	Non-Pension Benefits Plan	Defined Benefit Pension Plan	Non-Pension Benefits Plan
Weighted average assumptions				
Benefit obligation				
Discount rate	7.50%	7.50%	5.50%	5.50%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%
Initial health care trend rate	-	5.67%	-	5.91%
Ultimate trend rate	-	4.27%	-	4.27%
Year ultimate rate reached	-	2014	-	2016
Benefit expense				
Discount rate	5.50%	5.50%	5.25%	5.25%
Long-term rate of return on plan assets	6.75%	-	6.75%	-
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%
Initial health care trend rate	-	5.92%	-	6.47%
Ultimate trend rate	-	4.24%	-	4.24%
Year ultimate rate reached	-	2014	-	2016
Accrued benefit obligations				
Balance, beginning of year	\$ 51,002	\$ 8,223	\$ 49,771	\$ 7,598
Current service cost	930	294	979	304
Interest cost	2,813	461	2,700	435
Employee contributions	385	-	381	-
Net benefit payments	(2,432)	(257)	(2,521)	(261)
Actuarial (gain) loss	(11,910)	(2,434)	(308)	147
Balance, end of year	\$ 40,788	\$ 6,287	\$ 51,002	\$ 8,223
Fair value plan assets				
Balance, beginning of year	\$ 50,275	\$ -	\$ 47,976	\$ -
Employer contributions	1,489	257	2,398	261
Employee contributions	385	-	381	-
Actual return on plan assets	(8,646)	-	2,041	-
Benefits paid	(2,432)	(257)	(2,521)	(261)
Balance, end of year	\$ 41,071	\$ -	\$ 50,275	\$ -
Reconciliation of accrued benefit liability				
Plan surplus (deficit)	\$ 283	\$ (6,287)	\$ (727)	\$ (8,223)
Unamortized transitional obligation	2,822	3,490	3,342	3,989
Unamortized net actuarial loss (gain)	2,682	(3,820)	2,567	(1,421)
Valuation allowance	(142)	-	(252)	-
Accrued benefit asset (liability)	\$ 5,645	\$ (6,617)	\$ 4,930	\$ (5,655)

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

	2008		2007	
	Defined Benefit Pension Plan	Non-Pension Benefits Plan	Defined Benefit Pension Plan	Non-Pension Benefits Plan
Expense				
Current service costs	\$ 930	\$ 294	\$ 979	\$ 304
Interest cost	2,813	461	2,700	435
Actual return on plan assets	8,646	-	(2,041)	-
Actuarial (gain) loss	(11,910)	(2,434)	(308)	147
Costs arising in the year	479	(1,679)	1,330	886
Differences between costs arising in the period and costs recognized in the period in respect of:				
Actuarial (gain) loss	11,910	2,399	308	(162)
Return on plan assets	(12,024)	-	(1,206)	-
Transitional obligation	520	499	520	499
Increase in valuation allowance provided against accrued benefit asset	(112)	-	26	-
Net expense	\$ 773	\$ 1,219	\$ 978	\$ 1,223

The accrued benefit liability allocated to the Division as at December 31, 2008 and 2007 is \$1,220 and \$280, respectively and has been recorded in accounts and other payables.

In 2008, the total employer expense for the Division's defined contribution pension plan was \$133 (2007 - \$128).

Actuarial valuations

Actuarial valuations for these plans are required every three years. The most recent actuarial valuations for the pension and non-pension benefit plans ranged from June 1, 2006 to December 31, 2006. GLPL measures its accrued benefit obligations and the fair value of plan assets for accounting purposes as at December 31 of each year. The valuations include an indexation of pension payments of 2.50% per year (2007 - 2.00% per year). GLPL may choose to perform valuations for these plans prior to the earliest required dates.

Sensitivity analysis

GLPL's sensitivity in the non-pension benefit plan to a 1% change in the health care cost trend rate, for the year ended December 31, 2008, is summarized as follows:

	Benefit Obligation	Benefit Expense
Impact of a 1% increase in health care cost trend rate	\$ 1,202	\$ 212
Impact of a 1% decrease in health care cost trend rate	\$ (946)	\$ (155)

Asset category

GLPL's defined benefit pension plan asset allocations at December 31, by asset category are as follows:

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

	2008	2007
Equity securities	59%	60%
Debt securities	41%	40%
Total	100%	100%

Cash payments

All employer contributions were fully paid during the year and as such, no balance owing remains outstanding as at year-end.

8. STATEMENT OF CASH FLOWS

The change in non-cash working capital is comprised of the following:

	2008	2007
Accounts and interest receivable	\$ (6,648)	\$ 1,046
Due from related parties	-	26
Prepaid expenses and other	4	(33)
Materials and supplies	(39)	(21)
Long-term portion of rate mitigation accrual	(1,200)	(2,620)
Accounts and other payables	1,954	(128)
Due to related parties	1,281	(9,480)
Taxes payable	1,742	118
Regulatory assets and liabilities (net)	(600)	208
	\$ (3,506)	\$ (10,884)

Capital asset additions totaling \$518 which were included in accruals at December 31, 2007, have been included in the statement of cash flows for 2008, as they resulted in a cash outflow during the year. Similarly, capital asset additions totaling \$536 included in accruals at December 31, 2008, have been excluded from the statement of cash flows for 2008, as they did not result in a cash outflow during the year.

9. EFFECTS OF RATE REGULATION

The Division operates in accordance with the regulations of the OEB. Regulatory assets and liabilities represent certain revenues earned or costs incurred in the current year or in prior years that have been or are expected to be recovered from customers upon approval from the OEB. In the absence of rate regulation, these balances would have been recorded as revenues or expenses in the statement of operations and comprehensive income (loss).

As a result of the OEB's October 30, 2008 Decision and Order (the "Decision") on the Division's August 31, 2007 rate application, there have been a number of changes to existing regulatory asset balances between December 31, 2007 and December 31, 2008.

a) The Division recorded the following regulatory assets and liabilities as at December 31:

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

	2008	2007
<i>Regulatory assets</i>		
OEB variance accounts	\$ 891	\$ 1,109
Seasonal revenue accrual	1,106	-
Smart meter variance account	110	-
OEB cost assessment fees	-	156
	\$ 2,107	\$ 1,265
<i>Regulatory liabilities</i>		
Transition costs recovery	\$ -	\$ 767
PILs variance account	109	-
Regulatory asset recovery	900	-
	\$ 1,009	\$ 767

OEB variance accounts

As prescribed by regulatory order, OEB variance accounts are used to record the net of amounts charged by the IESO and amounts billed to customers, resulting in a regulatory asset or liability. These balances will be recovered or refunded through rates as approved by the OEB.

In the Decision, the OEB approved \$103 for recovery of OEB variance accounts. This balance was transferred to the regulatory asset recovery account.

Seasonal revenue accrual

The seasonal revenue accrual is related to a shortfall in revenue contributions from the seasonal customer class. The total cost allocated to the seasonal customer class is significantly higher than the total revenue generated through rates by that class. In order to recover the full cost, significant rate shock would have been incurred. In the Decision, the OEB accepted the Division's proposal to mitigate significant rate impacts to the seasonal customer class by limiting the rate increase to 10%. The shortfall in revenue would be accrued and recovered in a future period. The risk of the OEB ultimately denying the amounts is minimal, as the account has been approved for use in this context.

Smart meter variance account

In 2006, the Ontario Government committed to install a smart electricity meter in all Ontario homes and small business by the end of 2010. Distributors will be eligible to recover all prudent and reasonable costs that arise from this smart metering initiative.

As prescribed by regulatory order, this regulatory account shall be used by the distributor to record incremental operating, maintenance, amortization and administrative expenses directly related to smart meters. The risk of non-approval of this balance is negligible because the Division believes that the costs are prudent and reasonable, and recovery is prescribed by regulatory order.

OEB cost assessment fees

As prescribed by regulatory order, this regulatory account relates to the recovery of cost assessment fees in 2004 and 2005. This balance was approved in the Decision on the 2007 rate application and upon approval, was transferred to the regulatory asset recovery account.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

Transition costs recovery

As prescribed by regulatory order, this regulatory account relates to the recovery of certain allowed transition costs based on the OEB interim regulatory asset recovery order. This balance was approved in the Decision on the 2007 rate application and upon approval, was transferred to the regulatory asset recovery account.

PILs variance account

As prescribed by regulatory order, this regulatory account relates to the true-up of over- or under-collected funds related to tax recovery by the Division. Statutory changes in tax legislation should not impact a distributor's earnings, therefore any variance in a distributor's tax payable (from approved amount) resulting from a statutory change is to be recorded as an offset in this account. The balance of this account will be returned to the Division's ratepayers after a future proceeding with the OEB.

Regulatory asset recovery

As a result of the OEB's findings in the Decision, a number of regulatory accounts were approved for recovery and combined in one regulatory account. Also included in this account were all funds collected from 2004 through 2008 related to regulatory asset recovery. The balance of this account was to be recovered from customers or returned to customers, depending on the ultimate balance. As of December 31, 2008, \$900 was in this account, payable to the Division's ratepayers.

b) Rate mitigation accrual

The rate mitigation accrual relates to the return on equity portion of the revenue requirement from the 2002 rate application to the OEB. Distribution revenue in the amount of \$14,890 (2007 - \$14,756) has been accrued in accordance with the mitigation strategy submitted with the 2002 rate application, with the current portion in the amount \$0 (2007 - \$1,066) recorded in accounts and interest receivable.

On August 31, 2007, management filed an application to the OEB to continue recovery of its rate mitigation accrual balance up to the date the proposed rates become effective. In the OEB's Decision, recovery of the entire account balance was denied, and any collected funds were to be transferred to the regulatory asset recovery account, and returned to the Division's ratepayers.

On November 28, 2008, management filed an appeal of the portion of the Decision that denied the rate mitigation accrual. The appeal factum was filed with the Ontario Superior Court of Justice, and was filed on the basis that the OEB erred in law. As of the date these financial statements were issued, no updated information was available.

10. COMMITMENTS, CONTINGENCIES AND GUARANTEES

In the normal course of operations, the Division executes agreements that provide for indemnification and guarantees to third parties in transactions such as debt issuances. The nature of substantially all of the indemnification undertakings prevents the Division from making a reasonable estimate of the maximum potential amount the Division could be required to pay third parties as the agreements do not 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, the Division has not made significant payments under such indemnification agreements.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

The Division may, from time to time, be involved in legal proceedings, claims, and litigation that arise in the ordinary course of business which the Division believes would not reasonably be expected to have a material adverse effect on the financial condition of the Division.

The Division has asset retirement obligations associated with its property, plant and equipment. The retirement date for these assets cannot be reasonably estimated and therefore the fair value of the associated liability cannot be estimated at this time. As a result, no liability has been accrued in these financial statements.

11. CAPITAL MANAGEMENT

On January 1, 2008, the Division adopted CICA Handbook Section 1535, Capital Disclosures. This section requires disclosure of the Division's objectives, policies and processes for managing capital, the quantitative data about what the Division regards as capital, whether any capital requirements have been met, and if not, the consequences of such non-compliance.

The Division's objective when managing its capital structure is to uphold a strong capital base so as to maintain shareholder, creditor and market confidence and to sustain future development of the business. In addition, the Division strives to continue as a going concern, while providing an adequate return to its shareholder. In the management of capital, the Division includes the capital account and long-term debt in the definition of capital.

There were no changes in the Division's approach to capital management during the year.

12. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

On January 1, 2008, the Division adopted CICA Handbook Sections 3862 and 3863, Financial Instruments – Disclosures and Presentation. These sections replace section 3861 Financial Instruments – Disclosure and Presentation and place an increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how those risks are managed.

The Division classifies its financial assets and liabilities as outlined below:

Cash is designated as a financial asset held-for-trading and is measured at fair value through net income at each period end.

Accounts receivable as well as due from related parties are classified as loans and receivables, accounts and other payables, and due to related parties are classified as other financial liabilities, and each are measured at fair value at inception and, except for certain related party transactions, are subsequently measured at amortized cost using the effective interest method.

The carrying value approximates fair value for the Division's financial assets and liabilities, with the exception of long-term debt.

The Division has exposure to the following risks from its use of financial instruments: market risk, credit risk and liquidity risk. The Division's management is responsible for determining the acceptable level of risk.

GREAT LAKES POWER LIMITED DISTRIBUTION DIVISION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 2008

(in thousands of CDN dollars)

Market Risk

Market risk is the risk that the fair value of future cash flows of financial assets or liabilities will fluctuate due to movements in market prices.

Interest Rates:

The Division's capital debt facility debt bears interest at a rate set periodically by the OEB. Consequently, there is cash flow exposure. However, fluctuations in market interest rates are not expected to materially affect the Division's cash flows. This is a result of: (i) the Division's debt being held by another division of GLPL, and (ii) interest cost recovery being monitored by the OEB to ensure the appropriate level of interest is recovered.

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 Division would incur a loss in replacing the defaulted transaction. The Division's financial instruments that are potentially exposed to credit risks are accounts and interest receivable. The Division 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 continually monitors these exposures.

These risks are reviewed on a regular basis and the Division believes the exposures are manageable and not material in relation to its overall business operations.

Liquidity Risk

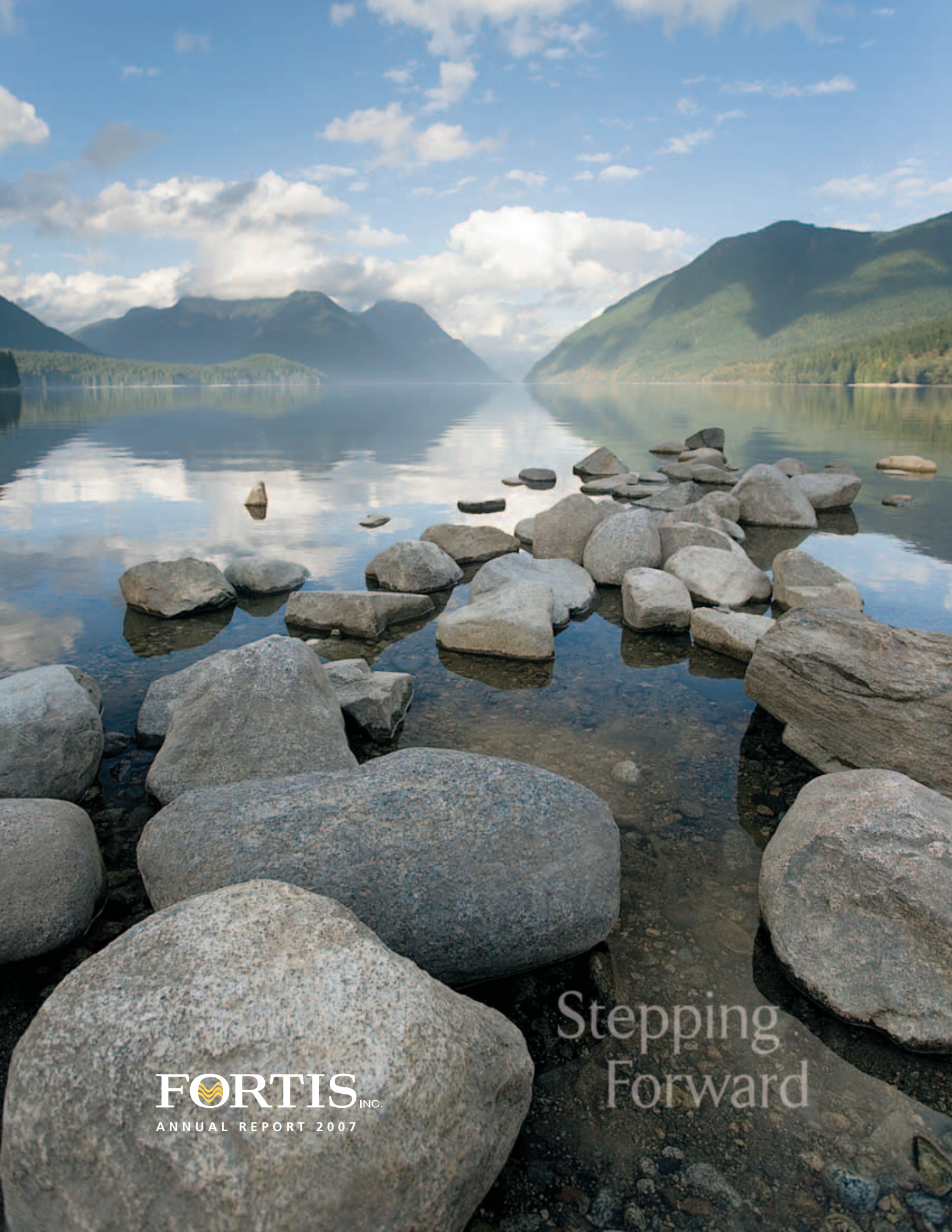
Liquidity risk is the risk the Division cannot meet a demand for cash or fund an obligation when due. Liquidity risk is mitigated by the Division's cash and cash equivalent balances, and management of amounts due from related parties.

Appendix F

Appendix F

Filed in confidence in accordance with
the Ontario Energy Board
Practice Direction on Confidential Filings

Appendix G



FORTIS_{INC.}
ANNUAL REPORT 2007

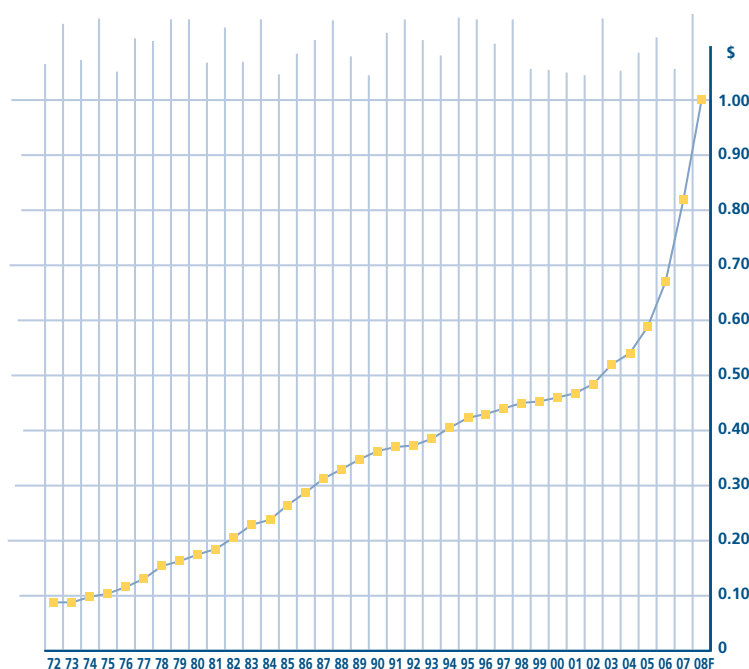
Stepping
Forward

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STEPPING FORWARD

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Dividends paid per common share



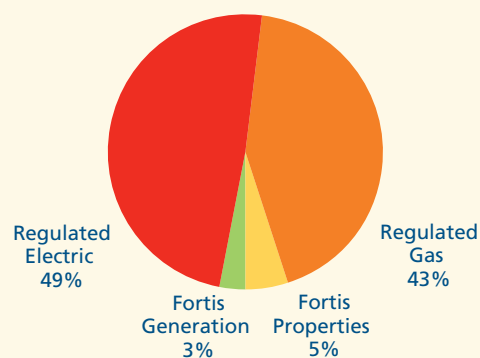
Fortis has increased its annual dividend to common shareholders for 35 consecutive years, the longest record of any public corporation in Canada.

Corporate Profile

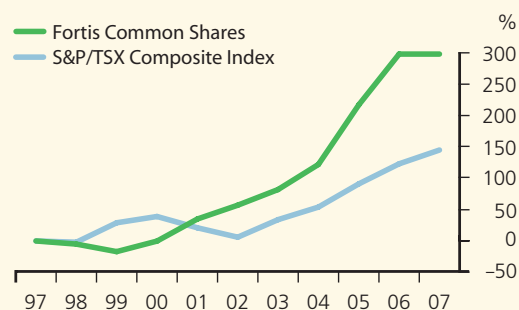
Fortis Inc. is the largest investor-owned distribution utility in Canada, serving almost 2,000,000 gas and electricity customers.

Total Assets Exceed \$10 Billion

(as at December 31, 2007)



10-Year Cumulative Total Return





Regulated Utility Operations

Gas Operations ◆

Terasen *British Columbia*

Electric Operations ■

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Belize Electricity *Belize*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation ●

Production Areas

*Belize, Ontario, Central Newfoundland,
British Columbia, Upper New York State*

Fortis Properties ▲

Real Estate

Atlantic Canada, Saskatchewan

Hotels

*Eastern Canada, Manitoba, Saskatchewan,
Alberta, British Columbia*

◆ ■ ▲ Alberta

▲ Manitoba

▲ Saskatchewan

◆ ■ ● ▲ British Columbia

Newfoundland ■ ● ▲

Prince Edward Island ■

■ ● ▲ Ontario

▲ New Brunswick

Nova Scotia ▲

● New York State

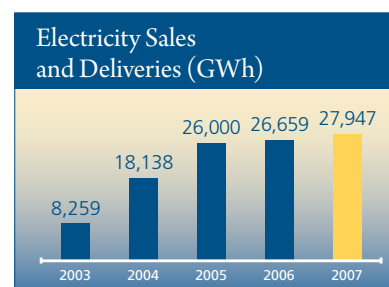
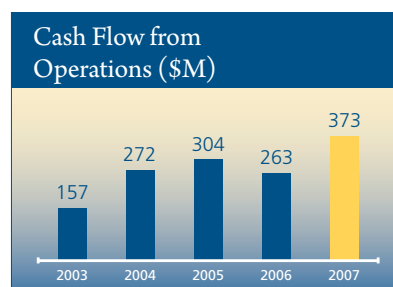
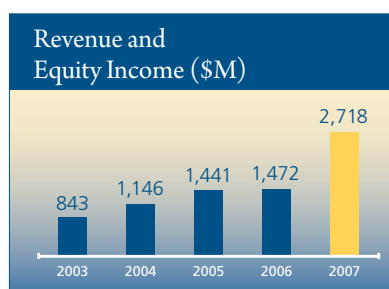
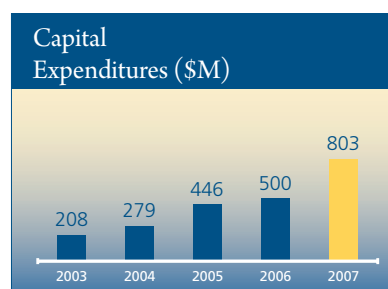
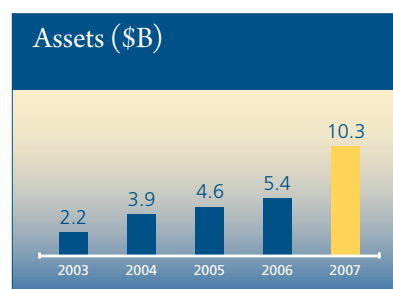
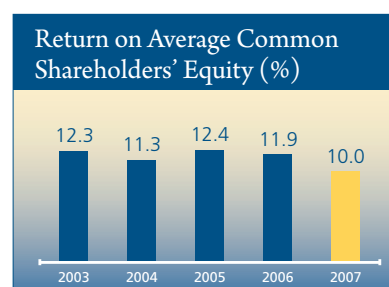
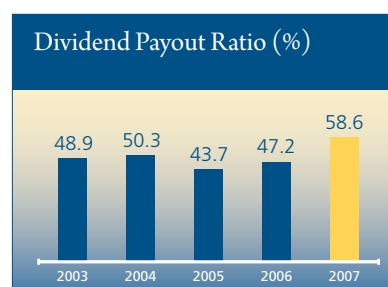
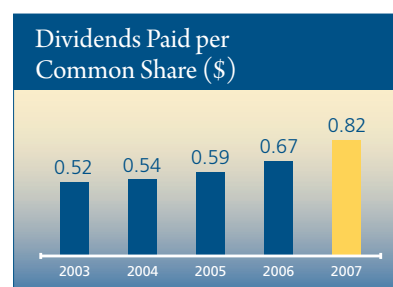
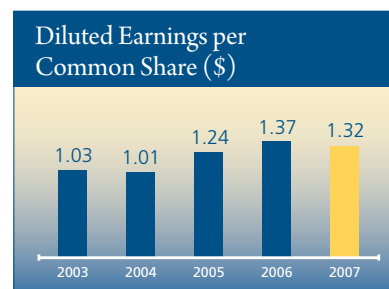
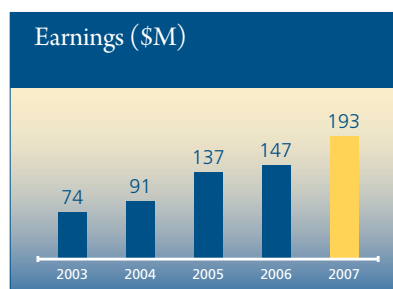
Turks and Caicos Islands ■

■ Grand Cayman

■ ● Belize

Investor Highlights

FIVE-YEAR PERFORMANCE



All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2007 unless otherwise indicated.

BUSINESS SEGMENTS

REGULATED

Gas

Terasen ⁽¹⁾	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Total Assets (\$M)	Capital Program (\$M)	Rate Base (\$M) ⁽²⁾	Earnings (\$M) ⁽³⁾	Allowed ROE (%) ⁽⁴⁾	
									2007	2008
Total	918,000	1,200	1,360	118	4,447	120	2,945	50	8.37	8.62

Electric

Company	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Total Assets (\$M)	Capital Program (\$M)	Rate Base (\$M) ⁽²⁾	Earnings (\$M) ⁽³⁾	Allowed ROE (%) ⁽⁴⁾	
									2007	2008
FortisAlberta	448,000	999	3,182	15,378	1,521	285	1,129	48	8.51	8.75
FortisBC	154,000	532	683	3,091	1,135	147	823	31	8.77	9.02
Newfoundland Power	232,000	555	1,142	5,093	986	72	817	30	8.60	8.95
Maritime Electric	72,000	179	218	1,035	367	27	277	10	10.25	10.00
FortisOntario	52,000	124	234	1,174	180	11	111	6	9.00	9.00
Belize Electricity ⁽⁵⁾	73,000	274	70	382	206	25	179	12	10.00–15.00 ⁽⁶⁾	10.00–15.00 ⁽⁶⁾
Caribbean Utilities ⁽⁷⁾	23,000	193	93	527	448	56	320	9	15.00 ⁽⁶⁾	10.00 ⁽⁶⁾⁽⁸⁾
Fortis Turks and Caicos	8,700	80	28	145	124	25	99	10	17.50 ⁽⁶⁾	17.50 ⁽⁶⁾
Total	1,062,700	2,936	5,650	26,825	4,967	648	3,755	156		

(1) Terasen primarily includes the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., collectively known as the "Terasen Gas companies". Gas volumes, capital program and earnings are from May 17, 2007, the date of acquisition.

(2) Forecast mid-year 2008

(3) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2007

(4) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. ROE for Terasen Gas (Vancouver Island) Inc. is 70 basis points higher.

(5) Fortis holds a 70.1% interest in Belize Electricity. Information in table represents 100% of Belize Electricity's operations except for earnings data.

(6) Regulated rate of return on rate base assets

(7) Fortis holds a 54% interest in Caribbean Utilities. Information in table represents 100% of Caribbean Utilities' operations for the 12 months ended October 31, 2007, except for earnings data.

(8) As per proposed new licence expected to be issued during the first half of 2008.

NON-REGULATED

Fortis Generation⁽¹⁾

	Generating Capacity (MW)	Energy Sales (GWh)	Assets ⁽³⁾ (\$M)	Earnings ⁽⁴⁾ (\$M)	Capital Program (\$M)
Total	195	1,122	324	24	22

Fortis Properties⁽²⁾

	Employees (#)	Assets (\$M)	Earnings ⁽⁴⁾ (\$M)	Capital Program (\$M)
Total	1,800	535	24	13

(1) Includes operations in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State

(2) Includes approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada and 19 hotels across Canada

(3) Includes \$89 million in "Other" non-regulated assets

(4) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2007

Information is for the fiscal year ended December 31, 2007 unless otherwise indicated.

Report to Shareholders

Fortis has delivered record earnings for the 8th consecutive year. It was also a year of record growth with our expansion into natural gas distribution through the acquisition of Terasen. The \$3.7 billion acquisition doubled the Corporation's regulated rate base to approximately \$6.3 billion and established Fortis as the largest investor-owned distribution utility in Canada.

Earnings applicable to common shares were \$193 million in 2007, 31 per cent higher than earnings of \$147 million last year. The growth in earnings was primarily attributable to the acquisition of Terasen in May, but also reflected the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes. Earnings per common share were \$1.40 compared to \$1.42 in 2006. The Terasen acquisition diluted earnings per common share by approximately 7 cents in 2007 due to the seasonality of that company's earnings.

Building on our track record of dividend growth, dividends paid per common share grew to 82 cents in 2007, up 22 per cent from 67 cents the previous year. The dividend payout ratio was 58.6 per cent in 2007. Your Board of Directors increased the quarterly common share dividend to 25 cents from 21 cents, commencing with the first quarter dividend paid on March 1, 2008. The increase extends the Corporation's record of annual common share dividend increases to 35 consecutive years, the longest record of any public corporation in Canada. Growth in earnings has enabled Fortis to increase its quarterly common share dividend by 92 per cent since 2003.



Fortis electric utilities own and/or operate approximately 134,000 kilometres of transmission and distribution lines.



Stan Marshall, President and CEO, Fortis Inc. (left) and Bruce Chafe, Chair of the Board, Fortis Inc. (right)

In 2007, Fortis common shares reached a high of \$30.00 and closed for the year at \$28.99. Over the past five years, Fortis has delivered an average annualized total return of 20.9 per cent, exceeding the results of the S&P/TSX Composite Index and the S&P/TSX Utilities Index, which delivered average annualized total returns of 18.3 per cent and 17.2 per cent, respectively, over the same period.

Our common share market capitalization surpassed \$4.5 billion in 2007, \$1.4 billion higher than in 2006. The average daily trading volume of Fortis common shares exceeded 400,000 compared to 240,000 in 2006.

We expect the Terasen acquisition to be accretive to earnings per common share of Fortis over the first full year of our ownership. It is a well-managed company and one of the largest natural gas distributors in Canada, serving more than 918,000 customers or 96 per cent of gas users in British Columbia. Its integration within the Fortis Group of Companies is progressing well.

The appointment of a majority of independent directors to the Board of Directors of Terasen in November 2007 was a significant step, ensuring that Terasen operates consistent with the Fortis model, with its own board and management. We welcome our 1,200 Terasen employees to the Fortis Group and look forward to their contribution in building on our world-class reputation for operating efficient utilities and delivering quality customer service. Subsequent to the acquisition of Terasen, Standard & Poor's ("S&P") raised the unsecured debt credit rating of Fortis two notches to 'A-' from 'BBB'. The unsecured debt of Fortis is rated BBB (high) by DBRS.

The gas distribution business of Terasen, which is comprised of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., and Terasen Gas (Whistler) Inc., contributed \$50 million to earnings since the acquisition in May. Because of its seasonal space-heating load, virtually all of the earnings of Terasen are generated in the first and fourth quarters.



In 2007, Fortis expanded into natural gas distribution through the acquisition of Terasen.



Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. The generating capacity of these assets is 195 megawatts ("MW"), 190 MW of which is hydroelectric generation.

Report to Shareholders

Canadian Regulated Electric Utilities delivered \$125 million in earnings, 10.6 per cent higher than earnings of \$113 million in 2006. The increase was driven by additional investment in electrical infrastructure to meet customer growth at FortisAlberta and FortisBC but also reflected higher corporate income tax recoveries at FortisAlberta, rate increases at FortisBC and a one-time after-tax gain of approximately \$2 million at FortisOntario.

Caribbean Regulated Electric Utilities contributed \$31 million to earnings, \$8 million higher than earnings in 2006, notwithstanding the impact of unfavourable foreign exchange rates associated with the strengthening Canadian dollar. Performance was enhanced by the first full year of earnings' contribution from Fortis Turks and Caicos, electricity sales growth at the three utilities and lower finance charges at Belize Electricity. Caribbean Utilities reported lower earnings due largely to a charge associated with the disposal of steam-turbine assets.



Utility capital expenditures, before customer contributions, were approximately \$790 million, including approximately \$120 million related to the Terasen Gas companies from the date of acquisition, in 2007.

Utility capital expenditures, before customer contributions, were approximately \$790 million, including approximately \$120 million related to the Terasen Gas companies from the date of acquisition, in 2007. Over the past five years, our utilities have invested approximately \$2.1 billion, on a consolidated basis, in capital projects. Much of this investment occurred at our electric utilities in the high-growth region of western Canada, where growth in customers and energy demand continues at a strong pace.

A number of significant regulatory decisions received in 2007 and early 2008 should provide regulatory stability for 2008, enabling our utilities to focus on operations and meeting the energy needs of customers.

Terasen Gas Inc., FortisBC, Newfoundland Power and Maritime Electric received regulatory approval for their respective 2008 customer rates. In February 2008, FortisAlberta received regulatory approval for the Company's 2008 and 2009 electricity rates. The allowed rates of return on common equity for 2008 for the Corporation's four largest utilities, Terasen Gas Inc., FortisAlberta, FortisBC and Newfoundland Power, increased to 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively.

Terasen Gas (Vancouver Island) Inc. received conditional regulatory approval to construct and operate a 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island, which will better enable the Company to meet customers'

current and future gas demand. The \$200 million facility is anticipated to be in service by late 2011.

In December 2007, Caribbean Utilities reached an agreement in principle with the Government of the Cayman Islands on the terms of the Company's new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year transmission and distribution licence. The new licences are expected to be issued during the first half of 2008.

The Government of Belize enacted amendments simplifying the tariff-setting methodology at Belize Electricity. The amendments, enacted in December 2007, settled outstanding matters related to the June 2007 regulatory decision on customer rates.



Fortis Properties achieved another milestone in August 2007 when it expanded to an 8th Canadian province with the acquisition of the Delta Regina in Saskatchewan.



The Fortis Group of Companies serves almost 2,000,000 gas and electricity customers in five Canadian provinces and three Caribbean countries.

Report to Shareholders

Non-regulated Fortis Generation contributed earnings of \$24 million compared to \$27 million in 2006. Results were impacted by decreased hydroelectric production due to lower rainfall.

Belize Electric Company Limited ("BECOL") began construction of the US\$53 million 18-MW Vaca hydroelectric project, the final phase of a three-stage development on the Macal River in Belize, in May. Vaca is expected to increase average annual production from the Macal River by approximately 80 gigawatt hours ("GWh") to 240 GWh. Assuming normal hydrology, the facility is expected to be immediately accretive to earnings per common share when it comes online late in 2009.

For the 10th consecutive year, Fortis Properties delivered record earnings which were \$24 million in 2007. Results were driven by expanded hospitality operations in western Canada and a \$4 million favourable corporate tax adjustment. The Company achieved another milestone in August 2007 when it expanded its presence to an 8th Canadian province with the acquisition of the Delta Regina in Saskatchewan. This acquisition was immediately accretive to earnings per common share.



The consolidated capital program for the Fortis utilities in 2008 is forecasted to be approximately \$900 million. Over the next five years, cumulative capital expenditures are expected to surpass \$4 billion.

With the Terasen acquisition, the total assets of Fortis now exceed \$10 billion, almost double that of a year ago and 10 times larger than a decade ago.

Fortis and its subsidiaries raised approximately \$2.1 billion in the capital markets in 2007. Coincident with the closing of the Terasen acquisition, the Corporation issued approximately \$1.15 billion in Common Shares, the net proceeds of which were used to complete the purchase. The remaining purchase price was funded by assumed debt of \$2.4 billion and drawings on the Corporation's existing credit facility. In January 2007, Fortis completed a \$150 million Common Share issue, the net proceeds of which were used mainly to repay indebtedness incurred for acquisitions in 2006 and support the capital programs of our electric utilities in western Canada. Following the S&P credit rating upgrade, Fortis completed its first offering of 30-year debt in September 2007 when it issued, by way of private placement, US\$200 million 6.6% senior unsecured notes to US-based institutional investors. Fortis subsidiaries completed almost \$600 million of long-term debt issues during 2007.



With the Terasen acquisition, the total assets of Fortis now exceed \$10 billion, almost double that of a year ago and 10 times larger than a decade ago.



Robust capital investment should continue to drive strong organic growth in earnings and dividends.

The consolidated capital program for our utilities in 2008 is forecasted to be approximately \$900 million. Over the next five years, cumulative capital expenditures are expected to surpass \$4 billion. Most of this capital investment will occur at our operations in western Canada. By 2012, the combined rate base of FortisAlberta and FortisBC is expected to exceed \$3 billion, 76 per cent higher than today's level of \$1.7 billion. The combined rate base of all Fortis utilities is expected to grow to approximately \$8.6 billion in 2012 compared to the current level of approximately \$6.3 billion.

Robust capital investment should continue to drive strong organic growth in earnings and dividends.

While the integration of Terasen within the Fortis Group remains a priority for 2008, Fortis will pursue gas and electric utility acquisitions in Canada, the United States and the Caribbean.

There were a number of leadership changes throughout the Fortis Group during the year. Karl Smith was appointed President and Chief Executive Officer, FortisAlberta following the retirement of Philip Hughes. Earl Ludlow succeeded

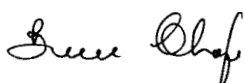
Report to Shareholders

Karl as President and Chief Executive Officer, Newfoundland Power. Nora Duke, formerly Vice President, Hospitality Services, Fortis Properties, succeeded Earl as President and Chief Executive Officer, Fortis Properties. Eddinton Powell, formerly Vice President Finance and Chief Financial Officer, Caribbean Utilities, was appointed President and Chief Executive Officer, Fortis Turks and Caicos. With the acquisition of Terasen, its President and Chief Executive Officer, Randall Jespersen, became part of the senior Fortis team.

The success of your Company attests to the calibre and commitment of our employees. Thank you for a job well done.

Messrs. Harry McWatters and Frank Crothers joined our Board of Directors in May 2007, bringing geographic representation for British Columbia and the Caribbean, respectively, and providing additional insight and strengths.

On behalf of the Board of Directors,



Bruce Chafe
Chair of the Board
Fortis Inc.



H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.



Stan Marshall, President and CEO, Fortis Inc., addresses the Toronto Board of Trade.



The success of Fortis attests to the calibre and commitment of our almost 6,000 employees.

As I will be retiring from your Board of Directors at the Annual Meeting on May 6, 2008, I would like to take this opportunity to extend my thanks and best wishes to the organization. To our employee group, now almost 6,000 strong, your hard work and customer care will continue to underpin the success of our Company.

Bruce Chafe
Chair of the Board
Fortis Inc.

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

- i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.
- ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.
- iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.



Terasen

REGULATED GAS OPERATIONS

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving more than 918,000 customers in 125 communities or 96 per cent of gas users in the province.

The Company's regulated natural gas and piped-propane distribution business is carried out by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), collectively known as the "Terasen Gas companies". Terasen's operations also include Terasen Energy Services, an emerging company focused on integrating alternative energy into district energy systems.

TGI, the main business of Terasen, provides natural gas distribution services to approximately 825,000 customers in over 100 communities. Its service territory extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast. It serves approximately 91,200 customers.

TGWI owns and operates the propane distribution system in Whistler, providing service to approximately 2,400 customers.

The Terasen Gas companies own and operate more than 45,000 kilometres of natural gas distribution and transmission pipelines. In 2007, gas volumes were over 220,000 terajoules ("TJ") with a peak day demand of 1,360 TJ. Terasen delivers approximately 20 per cent of the end-use energy consumed in British Columbia.

The Customer Choice Program, a new program introduced in British Columbia in May 2007, provides residential customers in most service areas in mainland British Columbia with the option of buying natural gas from an independent gas marketer at a multi-year fixed rate or from TGI at a variable rate. The Program, which gives flexibility to customers, does not impact TGI's earnings as natural gas costs are a direct flow through to customers.



In November, TGVI received conditional regulatory approval to construct and operate a 1.5 billion-cubic foot liquefied natural gas storage facility at Mount Hayes on Vancouver Island.



Officers of Terasen (l-r): Douglas Stout, VP, Marketing and Business Development; David Bennett, VP, Regulatory Affairs and General Counsel; Jan Marston, VP, Gas Supply and Transmission; Robert Samels, VP, Business Services and CIO; Daryle Britton, VP, HR and Operations Governance; Scott Thomson, VP, Regulatory Affairs and CFO; Roger Dall'Antonio, VP, Corporate Development and Treasurer; Dwain Bell, VP, Distribution; Randall Jespersen, President and CEO

The Terasen Gas companies achieved a Customer Satisfaction Rating of 79 per cent in 2007, its highest rating ever. Terasen's team of 1,200 employees undertook a number of initiatives that helped bolster performance, including productivity enhancements, process changes and new sales and marketing activities. Notable activities included increased advertising and communications necessary to support the introduction of the Customer Choice Program and a comprehensive website redesign.

In cooperation with FortisBC and BC Hydro, and with funding from the provincial and federal governments, TGI encouraged customers to conserve energy and save money by offering them financial incentives to upgrade to high-efficiency natural gas heating systems. It is estimated that the approximately 5,000 customers who participated in the Energy Star Furnace-Upgrade Program in 2007 collectively conserved 63,000 gigajoules of energy and reduced their energy costs by \$733,000 over the year.

In 2007, the Terasen Gas companies completed approximately \$185 million, before customer contributions, in capital programs to ensure the safe, reliable delivery of energy to customers. Major initiatives included an upgrade, reflecting safety advances in piping,

to 95 kilometres of natural gas distribution pipelines and 7,100 household services in five Vancouver neighbourhoods. Construction also began on a 50-kilometre ("km") natural gas pipeline from Squamish to serve Whistler. Once completed, the propane system in Whistler will be replaced by natural gas. In November, conditional regulatory approval was received to construct and operate a 1.5 billion-cubic foot liquefied natural gas storage facility at Mount Hayes on Vancouver Island. The new storage facility, estimated to cost between \$175 million and \$200 million, will allow for more efficient use of existing pipeline systems. It will result in improved reliability and security of supply during planned and unplanned system interruptions or in times of high demand. It is expected to come into service by late 2011.

TGI received regulatory approval for thermal metering, a new water-heating measurement method that promotes energy conservation for multi-family complexes. It also provides long-term growth opportunities for the utility through increased market share in British Columbia's growing housing sector.

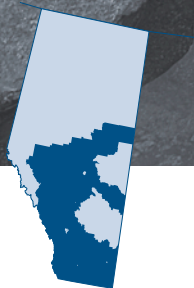
The Terasen Gas companies continued to focus on environmental and safety initiatives, including progress on emissions-reduction requirements. The Transmission Group achieved a milestone, celebrating 33 years without a lost-time injury. Early in the year, the regional flood preparedness plan was implemented to deal with potential flooding from a historically high spring snow-pack melt. Together with the provincial and local governments, the utility helped ensure public safety concerning its natural gas system.

A new five-year collective agreement was negotiated with the Canadian Office and Professional Employees Union, Local 378. The agreement complements the five-year collective agreement negotiated with the International Brotherhood of Electrical Workers, Local 213 in 2006.

Terasen is well positioned as a leading and innovative contributor to British Columbia's energy future.



The Terasen Gas companies own and operate more than 45,000 kilometres of natural gas distribution and transmission pipelines.



FortisAlberta

REGULATED ELECTRIC OPERATIONS

FortisAlberta is an electric utility that distributes electricity, generated by other market participants, to end-use customers in southern and central Alberta. Its electricity system includes approximately 106,000 kilometres of distribution lines and comprises more than 60 per cent of Alberta's total electricity distribution network. The Company serves more than 448,000 customers in 175 growing communities and met a peak demand of 3,182 MW in 2007.

FortisAlberta operates in a dynamic, high-growth environment with significant energy demand. Delivering quality customer service is fundamental to the success of the business. The Company received a Customer Satisfaction Rating of 76 per cent in 2007, consistent with its average annual rating over the past three years.

Approximately \$285 million, before customer contributions, was invested in capital projects in 2007, driven largely by growth in customer demand. Capital projects included the construction of an additional \$1.5 million distribution line from the new Blackmud substation to support customer demand in the Leduc-Nisku area, which experienced a 10 per cent increase in load growth in 2007. A \$2.3 million upgrade of distribution facilities in the Fort Saskatchewan area was undertaken to support the growth of a heavy-oil upgrade megaproject. Approximately \$75 million was invested in projects to upgrade conductors and replace aging poles, switches and regulator equipment. New distribution lines were built in the Canmore and Olds areas to provide alternative lines and improve reliability given the increased load growth experienced in these areas in recent years. Work continued on the installation of automated distribution equipment in Airdrie, Banff, Leduc and St. Albert, which will reduce the amount of travel and patrol time required to locate line faults, enabling faster restoration of electricity service.

FortisAlberta worked closely with the transmission service provider and the Alberta Electric System Operator to add substation capacity and improve reliability in Olds, Innisfail, Suffield, Red Deer and Acheson. The Company opened its doors to three new operations facilities in St. Albert, Brooks and Sylvan Lake in 2007. Work continued on the construction of FortisAlberta's new \$29 million operations and customer service facility in Airdrie, which is expected to open in 2008.



FortisAlberta serves more than 448,000 customers and met a peak demand of 3,182 MW in 2007.



Officers of FortisAlberta (l-r): Daniel Pigeon, VP, Finance and CFO; Karl Smith, President and CEO; Gary Smith, VP, Operations and Engineering; Cynthia Johnston, VP, Customer Service; Alan Skiffington, VP, Corporate Services and CIO

A pilot program to install Automated Meter Infrastructure ("AMI") technology at more than 26,000 customer sites was successfully implemented in 2007. The technology improves billing accuracy, reduces billing inquiries and enhances customer service. AMI technology will be installed at the Company's remaining customer sites by 2010.

In Alberta's highly competitive labour market, FortisAlberta continues to focus on attracting, developing and retaining a skilled workforce. More than 330 positions were filled by existing staff and new employees this year.

Safe work practices resulted in performance that generally exceeds the Canadian average for utilities of comparable size within the Company's industry group. FortisAlberta led a cooperative safety program in partnership with other Alberta utilities and the Government of Alberta to reinforce the message about the hazards of high-voltage lines. Thirty field offices were recognized for achieving anniversary milestones without lost-time incidents. Nine offices attained seven or more years without a lost-time incident.



FortisBC

REGULATED ELECTRIC OPERATIONS

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving approximately 154,000 customers directly and indirectly. Its utility assets include 6,900 kilometres of transmission and distribution lines and four regulated hydroelectric generating plants with a combined capacity of 223 MW on the Kootenay River. The annual gross energy entitlement from the plants is approximately 1,591 GWh. The Company also manages 784 MW of hydroelectric generation through contract services. It generates approximately 45 per cent of its electricity requirements, with the balance met through power purchase agreements. The utility met a peak demand of 683 MW in 2007.

FortisBC achieved an average overall Customer Satisfaction Rating of 86 per cent in 2007, a marked improvement from its Customer Satisfaction Rating of 71 per cent three years earlier. Contact Centre personnel attained an average response time of 33.2 seconds and reduced the number of inbound calls almost 10 per cent from the previous year. The Company processed 466 residential extension quotes and 2,227 new service installations were completed in 2007. Based on consultation with customers, an enhanced bill format was designed and introduced.

Focused on creating opportunities for information-sharing and long-term cooperative relationships, FortisBC introduced a public open-house format and new strategies for proactive and timely communication on capital projects. Consultations were held with the public, stakeholders and First Nations on five major infrastructure projects.

In 2007, FortisBC invested a record \$147 million, before customer contributions, in capital projects to meet growing energy demand and replace aging infrastructure. A record number of transmission upgrades were completed this year. The new \$20 million Nk'Mip distribution substation and associated 18-km transmission line were constructed to create an additional source of supply into the growing Osoyoos area. The new 23-km transmission line to Big White, the first phase of the \$20 million Big White Project, was completed and construction began on the \$27 million Kettle Valley Substation Project in the Rock Creek area. Approximately \$20 million was invested in the utility's ongoing hydroelectric generation Upgrade and Life-Extension Program in 2007. The Program rebuilds the generating units and auxiliary systems, extending the life of the assets for an estimated additional 40 years.



In 2007, FortisBC invested a record \$147 million, before customer contributions, in capital projects to meet growing energy demand and replace aging infrastructure.

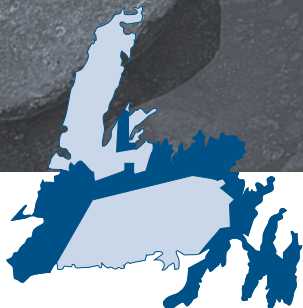


Officers of FortisBC (l-r): David Bennett, VP, Regulatory Affairs, General Counsel and Corporate Secretary; Michele Leeners, VP, Finance and CFO; Don Debiegne, VP, Generation; John Walker, President and CEO; Michael Mulcahy, VP, Customer and Corporate Services; Doyle Sam, VP, Transmission and Distribution

FortisBC continues to lead a cooperative safety awareness campaign in partnership with other British Columbia utilities and safety organizations. The Generation Department achieved over 365 days without a lost-time incident.

FortisBC is committed to environmental stewardship through partnerships with the South Okanagan-Similkameen Invasive Plant Society, the Boundary Weed Management Committee and the Central Kootenay Invasive Plant Committee. The utility also works with multi-agency groups committed to protecting the aquatic environment.

In November 2007, the Government of British Columbia announced the appointment of John Walker, President and Chief Executive Officer, FortisBC, to a new Climate Action Team. The Team's mandate is to make recommendations to the Province on actions to meet its commitment to become carbon neutral by 2010.



Newfoundland Power

REGULATED ELECTRIC OPERATIONS

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 232,000 customers or 85 per cent of electricity consumers in the province. It owns and operates 29 small generating stations with an installed generating capacity of approximately 139 MW, of which 96 MW is hydroelectric generation, and has approximately 11,000 kilometres of transmission and distribution lines. Newfoundland Power met a peak demand of 1,142 MW in 2007. About 90 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro").

More than 59 per cent of the \$72 million invested, before customer contributions, in capital projects in 2007 was directed to plant and equipment replacement to enhance reliability for customers. The remaining capital investment was driven by commercial and residential construction activity, growth in cottage areas and increased replacement of plant to accommodate fibre-optic cable installations by telecommunication companies in the province.

A \$17 million refurbishment of the Rattling Brook hydroelectric generating facility, the largest capital project in dollar terms ever undertaken by the Company, was completed in 2007. The refurbishment will increase the plant's generating capacity to 14.1 MW and should net a 9 per cent increase in power production. The plant now uses approximately 129,000 fewer barrels of oil annually, which will help minimize the impact of fuel costs on electricity rates and benefit the environment.

Strategic capital investment and employee commitment to customer service enabled electricity to be delivered to customers 99.93 per cent of the time in 2007, despite the impact of a severe snowstorm in December which caused major system damage and impacted upwards of 20,000 customers in the Clarenville and Bonavista areas.

While challenged with increasing energy prices, Newfoundland Power achieved a Customer Satisfaction Rating of 88 per cent in 2007 compared to 89 per cent last year. An independent survey conducted during the year ranked the Company the highest among Canadian utilities of similar size in satisfying residential customers.



A \$17 million refurbishment of the Rattling Brook hydroelectric generating facility, the largest capital project in dollar terms ever undertaken by Newfoundland Power, was completed in 2007.



Officers of Newfoundland Power (l-r): Lisa Hutchens, VP, Customer Relations and Corporate Services; Peter Alteen, VP, Regulatory Affairs and General Counsel; Phonse Delaney, VP, Engineering and Operations; Jocelyn Perry, VP, Finance and CFO; Earl Ludlow, President and CEO

Providing energy-efficiency programs and services continues to be a focus for the Company. The number of customers requesting energy-efficiency information increased 55 per cent and visits to the *Saving Energy* section of its website increased 76 per cent compared to 2006.

A long-term workforce strategy is in place to address future hiring needs. The utility participates in a trade apprenticeship program as well as post-secondary and high-school career fairs. Twenty apprentice linepersons were in training in 2007, the highest level for the utility since the early 1970s.

In 2007, Newfoundland Power achieved its best safety performance on record. The internationally recognized OHSAS 18001 Health and Safety Management System was implemented to further improve safety performance.

The Company was bestowed the Environmental Performance Award by the Newfoundland and Labrador Environmental Industry Association and received a Business Award of Excellence in the category "Contributions to the Community and Community Service" by the St. John's Board of Trade.

Maritime Electric

REGULATED ELECTRIC OPERATIONS

Maritime Electric, the principal electric utility on Prince Edward Island ("PEI"), serves approximately 72,000 customers, or 90 per cent of electricity consumers in the province, and met a peak demand of 218 MW in 2007. The utility owns and operates a fully integrated system comprised of more than 5,200 kilometres of transmission and distribution lines, providing for the generation, transmission and distribution of electricity across the Island. Maritime Electric maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined total capacity of 150 MW. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait.

In 2007, the Company purchased more than 87 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). It has entitlement to energy and capacity from NB Power's Point Lepreau and Dalhousie Generating Stations through agreements that extend for the life of these stations. The Point Lepreau Station will undergo an 18-month refurbishment beginning on April 1, 2008 that will extend its life by 25 years, providing additional stability with respect to long-term energy supply. The remainder of off-Island energy purchases is made at market prices under an agreement with NB Power. Maritime Electric obtains the balance of its energy requirements either from its own generating plants or from on-Island wind-powered generation facilities.

The Company invested approximately \$27 million, before customer contributions, in 2007 to improve system reliability and customer service. Construction was completed on a \$2.5 million 69-kilovolt ("kV") transmission line that delivers wind-powered energy from a commercial operation in western PEI to the North American grid. Maritime Electric supports the development of PEI's wind resource and its integration into the overall energy supply strategy in a timely and consistent manner. The Company issued a Request for Expressions of Interest for wind-powered energy development projects to ensure the utility's system-development planning process enables wind-powered energy to comprise part of PEI's long-term energy supply.

In September 2007, Maritime Electric secured 30 MW of transmission capacity on the International Power Line, a second transmission line between New Brunswick and Maine. This line will increase both northbound and southbound flows with New England and should increase energy supply options.



Maritime Electric invested approximately \$27 million, before customer contributions, in 2007 to improve system reliability and customer service.



Officers of Maritime Electric (l-r): Bill Geldert, VP, Finance, CFO and Corporate Secretary; Fred O'Brien, President and CEO; John Gaudet, VP, Corporate Planning and Energy Supply; Steve Loggie, VP, Customer Service

Maritime Electric received a Customer Satisfaction Rating of 73.3 per cent in 2007 compared to 79.5 per cent in 2006. A considerable number of customer outages in 2007 were due to extreme weather conditions including severe lightning, Tropical Storm Noel and a major ice storm.

An external audit of the Company's Safety Management System referenced numerous achievements since completion of the previous audit, particularly the many steps taken by Maritime Electric in demonstrating its commitment to safety. The development of a Safe Work Management System to manage safety and to document policies, procedures and programs was instrumental in the improvement of the overall rating. The completion of a new vehicle and crew assignment system helps meet the requirements of working-alone legislation.



FortisOntario

REGULATED ELECTRIC OPERATIONS

FortisOntario is an integrated electric utility which owns and operates Canadian Niagara Power and Cornwall Electric. Its utilities serve approximately 52,000 customers, mainly in Fort Erie, Port Colborne, Cornwall and Gananoque, Ontario. The Company owns regulated transmission assets in the Niagara and Cornwall regions, including an interconnection between New York State and Fort Erie, Ontario. It has more than 1,360 kilometres of transmission and distribution lines and met a combined peak demand of 234 MW in 2007. FortisOntario owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies serving more than 27,000 customers. The Company purchases its electricity from the Independent Electricity System Operator in Ontario, with the exception of Cornwall Electric which is supplied by Hydro-Québec.

FortisOntario invested \$11 million, before customer contributions, in capital expenditures in 2007 to connect new customers and upgrade its transmission and distribution assets to further improve system reliability and safety. During the year, work continued on the conversion of the 4.8-kV Fort Erie system to an 8.3-kV system. Progress was made on the Port Colborne SCADA expansion program, designed to enhance remote monitoring and control of substations. A new \$1.4 million substation was commissioned in Gananoque, providing improved reliability and security of service to the community. A Service Centre for Gananoque field operations was also refurbished, improving efficiencies for field personnel. Capital programs in Cornwall focused on new customer connections, as well as planned line improvements to replace deteriorated plant and improve system security. Major capital works included a 115-kV transmission line relocation and the replacement of aging underground distribution switching units.



In 2007, a new \$1.4 million substation was commissioned in Gananoque, providing improved reliability and security of service to the community.



Officers of FortisOntario (l-r): Scott Hawkes, VP, Corporate Services, General Counsel and Corporate Secretary; Glen King, VP, Finance and CFO; William Daley, President and CEO; Angus Orford, VP, Operations

FortisOntario achieved a Customer Satisfaction Rating of 83 per cent in 2007, similar to the rating achieved in 2006. Customers continue to rate reliability/safe delivery of electricity and quality of service as high priorities at 90 per cent and 85 per cent, respectively. The Company continues to exceed performance standards set by the Ontario Energy Board with respect to response times, service connections and call-answer statistics.

FortisOntario, in conjunction with the Ontario Power Authority, launched four electricity-conservation and demand-management programs in 2007. The Summer Savings Program encouraged customers to reduce electricity consumption by 10 per cent in July and August with a 10 per cent credit for customers achieving the reduction. More than 30 per cent of eligible customers met the reduction target.

FortisOntario met or exceeded all of its health, safety and environmental key performance indicators for 2007, including zero lost-time injuries for all work locations. FortisOntario, Cornwall Electric and Canadian Niagara Power each received the Silver Safety Award from the Electrical & Utilities Safety Association of Ontario in recognition of their successful plans to implement a sustainable health and safety management system.



Belize Electricity

REGULATED ELECTRIC OPERATIONS

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 73,000 customers, the utility met a peak demand of 70 MW in 2007 from multiple sources of energy, including power purchases from BECOL, Comisión Federal de Electricidad (the Mexican state-owned power company), Hydro Maya Limited and from its own diesel-fired and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Belize Electricity has an installed generating capacity of 36 MW and owns approximately 2,740 kilometres of transmission and distribution lines. Fortis holds a 70.1 per cent controlling interest in Belize Electricity.

Through its pursuit of competitively priced energy sources, the Company was able to maintain stable electricity rates in the face of record-breaking oil prices. Hydroelectricity supplied approximately 40 per cent of the country's peak energy demand, which grew by approximately 5 per cent in 2007.

Capital investments to expand and improve the electricity system surpassed US\$23.5 million, before customer contributions, in 2007. Almost 95 kilometres of distribution lines were constructed countrywide, including line extensions to electrify several rural communities under the Power III Rural Electrification Project, a joint initiative between Belize Electricity and the Government of Belize. Since the Project's establishment in 1999, approximately US\$15 million has been invested in capital initiatives for this Project and first-time service has been extended to more than 11,000 customers. Capital projects were also undertaken to connect tourism developments in the popular tourist destinations of San Pedro Town and Placencia Village, to connect a large-scale shrimp farm in southern Belize and to replace aging distribution systems in the Belize District.

During 2007, more than 7,000 electronic meters were installed to replace aging equipment. Improvements were also made to the bill-editing and meter-sealing programs and meter inspections continued countrywide.

Belize Electricity earned a Customer Satisfaction Rating of 84 per cent in 2007. A significant customer service initiative during the year was the installation of an Automated Call Distributor and Interactive Voice Response System. The System provides call-in customers with automated information such as service restoration times, bill payment due dates and account balances. An extensive renovation of the customer service office in Punta Gorda Town, the southernmost municipality in the country, was also completed during the year.



Officers of Belize Electricity (l-r): Joseph Sukhnandan, VP, Engineering and Energy Supply; Juliet Estell, Manager, Executive Services and Company Secretary; Lynn Young, President and CEO; Rene Blanco, VP, Finance and CFO; Felix Murrin, VP, Customer Care and Operations (Effective October 29, 2007, Mr. Curtis Eck was appointed VP, Customer Care and Operations following the retirement of Mr. Murrin.)



Belize Electricity earned a Customer Satisfaction Rating of 84 per cent in 2007.

Safety training remains an integral component of daily operations. In August 2007, the Company implemented a new service-installation guide consistent with the National Electric Code used in North America. Training by FortisAlberta now enables Belize Electricity to conduct independent in-house training on work methods, such as hot-stick and rubber-glove live-line maintenance techniques, which helps improve system reliability.

The Company continues to make meaningful progress towards becoming ISO 14001 compliant by 2009. The Environmental Management System is now implemented in all high-risk areas and efforts are underway to roll out the system to low-risk areas.



Caribbean Utilities

REGULATED ELECTRIC OPERATIONS

Caribbean Utilities generates, transmits and distributes electricity to more than 23,000 customers on Grand Cayman, Cayman Islands. The Company is one of the most reliable and efficient utilities in the region. The utility owns and operates approximately 550 kilometres of transmission and distribution lines and 22 kilometres of high-voltage submarine cable. Its electricity system has an installed generating capacity of approximately 137 MW and met a record peak demand of approximately 93 MW in August 2007.

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U. Fortis increased its investment in Caribbean Utilities to approximately 54 per cent in November 2006, becoming controlling shareholder.

Caribbean Utilities earned a Customer Satisfaction Rating of 84 per cent in 2007. Customer service initiatives undertaken throughout the year included marketing of external payment options, such as direct debit; implementation of Telelink, an automated voice-activated customer-service system; the continued installation of new automated meters; and promotion of the Energy Smart Program, designed to help customers conserve energy. The Company offers free residential and commercial energy audits to all customers as part of its Energy Smart activities.

System reliability was 99.95 per cent year-to-date October 31, 2007. Capital expenditures for the fiscal year ended April 30, 2007 totalled US\$36 million, before customer contributions. Major capital projects included the US\$22 million 16-MW diesel-fired generating unit and auxiliary equipment commissioned in June 2007, and transmission and distribution projects, which will further enhance system reliability. Information technology projects included the development of business continuity plans for several departments and an enterprise-wide Crisis Management and Business Continuity Plan.

Caribbean Utilities has a comprehensive Environmental Management System and was recertified as compliant with ISO 14001:2004 for its power generation, transmission and distribution systems. The Company is the only organization in the Cayman Islands with ISO 14001 certification. Environmental Management System initiatives included ongoing emergency preparedness planning, continuous employee education programs, and stringent environmental and structural design standards.



Caribbean Utilities owns and operates approximately 550 kilometres of transmission and distribution lines and 22 kilometres of high-voltage submarine cable.



Officers of Caribbean Utilities (l-r): Douglas Murray, Corporate Secretary; Letitia Lawrence, VP, Finance and CFO; Richard Hew, President and CEO; Andrew Small, VP, Transmission and Distribution; David Watler, VP, Production

With 193 employees, more than 90 per cent of whom are Caymanian, Caribbean Utilities recorded more than 11,000 employee training hours for its fiscal year 2007. Training initiatives included information technology instruction to a diverse group of employees, as well as an internationally recognized accredited apprenticeship program for employees of the Production and Transmission Division.

Employee and public safety practices remain a priority. Initiatives this year included contractor safety programs, revisions to energy-control procedures, Occupational Safety and Health Administration-certified courses and monthly health and safety meetings.

The Company continues its commitment to the "Investors in People" certification, which was achieved in early 2006. This internationally recognized standard aligns the utility's human resource strategies with its business objectives. Employee-development initiatives will continue throughout 2008 as the utility strives to maintain its employer-of-choice position in the country.

Fortis Turks and Caicos

REGULATED ELECTRIC OPERATIONS

Fortis Turks and Caicos serves more than 8,700 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands. It owns and operates a fully integrated system providing for the generation and distribution of energy in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037. It also owns and operates an independent generating station and distribution system on South Caicos and is the sole provider of electricity for that island pursuant to a 50-year licence that expires in 2036. The Company has a combined diesel-fired generating capacity of 48 MW and met a combined peak demand of 28 MW in 2007. Fortis Turks and Caicos owns and operates 325 kilometres of transmission and distribution lines.

A major focus has been the integration of Fortis Turks and Caicos within the Fortis Group of Companies since its acquisition in August 2006. In July 2007, Mr. Eddinton Powell, formerly Vice President Finance and Chief Financial Officer, Caribbean Utilities, took the helm as President and Chief Executive Officer, Fortis Turks and Caicos. Under his leadership, management remains focused on meeting the growing needs of customers.

The utility's customer base increased 13 per cent in 2007, driven largely by strong economic growth in the country. Current economic conditions on the Turks and Caicos Islands suggest the Company can expect to achieve growth in energy demand in the range of 18 per cent to 25 per cent per annum over the next several years. The robust growth in energy demand is being driven by tourism and the high level of condominium and hotel development. One of the utility's large hotel customers, for example, is investing US\$68 million to expand its facility to more than 600 rooms.

Fortis Turks and Caicos invested US\$24 million, before customer contributions, in capital projects in 2007 to meet current and projected growth in energy demand resulting from a rapidly growing customer base. Two diesel-fired generating units, with a combined generating capacity of 7 MW, were commissioned in 2007. Four additional units, with a combined generating capacity of 13 MW, were purchased during the year and will be installed in 2008 and 2009. The rapid increase in load has necessitated the expansion of the Richmond Hill and Grace Bay substations. The Grace Bay substation, which was brought into service only a year ago, is reaching its installed capacity and considerable work has been carried out to double its capacity by the end of 2008.



Officers of Fortis Turks and Caicos (l-r): Robert Hamill, VP, Finance and CFO; Brian Walsh, VP, Operations; Eddinton Powell, President and CEO; Allan Robinson, VP, Customer and Corporate Services; Ernest Jackson, VP, Production and Engineering



Fortis Turks and Caicos has a combined diesel-fired generating capacity of 48 MW and met a combined peak demand of 28 MW in 2007.

Throughout 2007, Fortis Turks and Caicos developed and implemented a number of programs designed to enhance customer service. A new Customer Care Centre was opened in December. The Company also installed a new automated meter-reading system that will greatly improve the efficiency of the meter-reading process. As part of its efforts to enhance customer relations, management is focused on developing strong working relationships with its on-island stakeholders.

Safety and employee development remain key operational priorities for Fortis Turks and Caicos. Throughout 2007, safety training was provided to employees in high-risk jobs and job-specific training was provided to meter technicians, control room operators, line apprentices, engineering service staff, customer service agents and information systems staff.

Fortis Generation

NON-REGULATED OPERATIONS

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State. The generating capacity of these non-regulated assets is 195 MW, 190 MW of which is hydroelectric generation.

In Belize, BECOL owns and operates the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities located on the Macal River. Mollejon and Chalillo are the largest commercial hydroelectric generating facilities in Belize. Energy production was 167 GWh in 2007, a slight decrease from last year due to lower rainfall levels. Production was still above expected levels based on historical average rainfall. BECOL sells its entire output to Belize Electricity under a 50-year Power Purchase Agreement ("PPA").

In May 2007, construction began on the US\$53 million 18-MW Vaca hydroelectric generating facility situated approximately five kilometres downstream of Mollejon. Vaca is the final phase of the three-stage hydroelectric development plan for the Macal River. The run-of-river facility will increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. Belize Electricity has signed a 50-year PPA with BECOL for the purchase of energy generated by the Vaca facility, commencing late in 2009.



In May 2007, construction began on the US\$53 million 18-MW Vaca hydroelectric generating facility situated approximately five kilometres downstream of Mollejon on the Macal River in Belize.

In Ontario, non-regulated operations include 75 MW of water-right entitlement associated with the Rankine hydroelectric generating station at Niagara Falls, a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. With the exception of the cogeneration plant in Cornwall, the electricity produced from these facilities is sold in Ontario at market prices.

In central Newfoundland, Fortis Generation holds a 51 per cent interest in the Exploits River Hydro Partnership ("Exploits Partnership") with Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"). The Exploits Partnership was established in 2001 and commenced operations in 2003 following the development of additional capacity at Abitibi-Consolidated's two hydroelectric generating plants in central Newfoundland. Abitibi-Consolidated continues to use the historical annual generation while the additional energy produced as a result of the project is sold to Newfoundland Hydro under a 30-year PPA. The Exploits Partnership achieved production of 137 GWh in 2007.

In British Columbia, the non-regulated asset is the 16-MW run-of-river Walden hydroelectric generating plant near Lillooet, which was acquired in May 2004 as part of the assets of FortisBC. The plant sells its entire output to BC Hydro under a long-term contract.

In Upper New York State, the non-regulated assets are four hydroelectric generating stations located in Moose River, Philadelphia, Dolgeville and Diana. The plants have a combined generating capacity of approximately 23 MW. The average annual 85 GWh of energy output of these modern facilities is sold at the wholesale level through a series of renewable contracts.

Fortis Properties

NON-REGULATED OPERATIONS

Fortis Properties owns and operates 19 hotels, offering more than 3,500 rooms, in eight Canadian provinces, and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada. The Company, a wholly owned subsidiary of Fortis, is the primary vehicle for non-utility diversification and growth.

In August 2007, Fortis Properties expanded to an 8th Canadian province with the acquisition of the Delta Regina in Saskatchewan. The complex is comprised of 274 hotel rooms, the Saskatchewan Trade and Convention Centre, 52,000 square feet of Class A commercial office space and a parking garage. The hotel strengthens the Company's hotel portfolio while increasing its presence in western Canada.

The Hospitality Division showed continued improvement in customer satisfaction ratings in 2007. The Delta St. John's Hotel and Conference Centre was recognized by Delta Hotels with the *Best in Class*, *Guest Satisfaction* and *Most Improved Guest Satisfaction* awards, recognizing employee excellence in customer service. Additionally, the Delta St. John's and Delta Brunswick placed in the top three for the *Hotel of the Year*, *Franchise* award. Revenue per available room ("REVPAR") increased for the 12th consecutive year, reaching \$79.31. The increase in REVPAR was primarily attributable to the addition of the four hotels in western Canada, acquired in November 2006, and the Delta Regina.

The Real Estate Division is anchored by high-quality tenants under long-term leases with a year-end occupancy rate of 96.8 per cent, outpacing the national rate of 93.8 per cent.

The Building Owners and Managers Association ("BOMA") Atlantic recognized Blue Cross Centre in Moncton, New Brunswick with the BOMA Environmental Stewardship Award. The award acknowledged the property's efforts in limiting its environmental impact through its energy-efficient building design, energy- and water-consumption tracking, and recycling initiatives.

The \$2 million recladding of the Delta Sydney in Nova Scotia was completed in November 2007. The project remedied building infrastructure issues and revitalized the property's exterior, increasing its attractiveness in the market. Work began on a \$1.4 million electrical refit at the Delta Brunswick/Brunswick Square complex to improve building infrastructure and ensure the continued comfort of guests and tenants.



Officers of Fortis Properties (l-r): Neal Jackman, VP, Finance and CFO; Nora Duke, President and CEO; Wayne Myers, VP, Real Estate



Fortis Properties owns and operates 19 hotels, offering more than 3,500 rooms, in eight Canadian provinces.

A Company-wide Health and Safety Plan was launched in 2007 with emphasis placed on key initiatives such as safety communication and leadership, safety training and orientation, incident reporting, contractor management, and early and safe return to work. Safety audits were conducted at 19 properties and will continue throughout 2008 for the remainder of the properties.

Employee development initiatives continued with the provision of special assignments and secondments to enhance employee performance. The Company's Mentoring Program continued and a renewed emphasis was placed on leadership development. Training was completed in the areas of respectful workplace, collective agreement administration, and health and safety.

Our Community

Our team spirit extends beyond our office buildings and operational facilities. It kicks into high gear on soccer fields, marches along in school parades, helps fill food bank shelves and champions scores of community events where volunteers make a difference in the quality of daily living for others.

In 2007, the Fortis Group of Companies contributed almost \$3 million in financial and in-kind donations to a wide spectrum of worthy community causes. Hundreds of our employees were involved.

Here's a few of the community initiatives we were proud to support:

Terasen donated 40 desktop computers to *Seabird Island First Nation*. The computers will be part of a network that will provide high-speed broadband wireless access to the community of Seabird Island.

FortisAlberta and its employees donated \$148,000 to the eight *United Way* chapters in its service territories across Alberta, exceeding the campaign goal of \$125,000 and surpassing the Company's 2006 donation by more than \$40,000.

FortisBC employees and volunteers participated in the 5th annual *Moving Mountains Relay*, a 370-km run from Trail to Kelowna. More than \$21,000 was raised to help purchase an osteotomy hip system for the Orthopedic Unit at the BC Children's Hospital.



Newfoundland Power pledged \$350,000 to *PRIORITY: The Campaign for Cancer Care* for the purchase of a new four-dimensional CT simulator for the Dr. H. Bliss Murphy Cancer Centre. The equipment will enable the cancer care team to enhance the accuracy of radiation treatment for cancer patients.

Maritime Electric sponsors an annual *\$5,000 Environmental Studies Grant Program*. The funds are used to help educate high school students about issues pertaining to the natural environment and how it can be managed in a sustainable manner.

FortisOntario donated a collection of historical documents, photos and artifacts depicting the beginning and evolution of electricity in Canada to the *Cornwall Museum*. Valued at more than \$230,000, the donation was the largest in the museum's history.

Belize Electricity has pledged US\$10,000 over three years to the *Belize Emergency Response Team*. The non-profit organization is the only fully trained and equipped ambulance service in Belize.

Employees of Caribbean Utilities contributed over 300 hours to community events. The Company was the principal sponsor of the *CUC Primary Football League* with more than 15 primary schools across Grand Cayman participating.

Fortis Turks and Caicos completed its first annual *Home Makeover* in December. Home is where the heart is and employees put their hearts into helping complete some major roof repairs, install new light fixtures and upgrade the property of a well-deserving community member.

Fortis Properties partnered with community groups and the Government of Newfoundland and Labrador on the *Makin' It Work* project. The initiative provides unemployed or underemployed persons with on-the-job training for frontline hospitality positions.

Thanks to our employees and all volunteers for stepping forward.

Management Discussion and Analysis

Dated March 14, 2008

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included in the Fortis Inc. 2007 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 – Continuous Disclosure Obligations. Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and is presented in Canadian dollars unless otherwise specified. Fortis Inc. ("Fortis" or the "Corporation") includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the Corporation's expectation to generate sufficient cash required to complete planned capital programs from a combination of long-term debt and short-term borrowings, internally generated funds and the issuance of common shares and preference shares; the Corporation's belief that it does not anticipate any difficulties in accessing the required capital on reasonable market terms; the Corporation's consolidated forecasted gross capital expenditures for 2008 and in total over the next five years, as well as expected significant capital projects in 2008 and their expected cost and time to complete; the Corporation's expectation of the impact of foreign exchange on 2008 basic earnings per common share; and the Corporation's belief that its capital program should drive growth in earnings and dividends. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major events; the Corporation's ability to maintain its gas and electricity systems to ensure their continued performance; the competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the availability of natural gas supply; favourable economic conditions; the level of interest rates; the ability to hedge certain risks; access to capital; maintenance of adequate insurance coverage; the ability to obtain licences and permits; the level of energy prices; retention of existing service areas; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. The factors which could cause results or events to differ from current expectations include, but are not limited to: regulation; integration of Terasen Inc. and management of expanded operations; operating and maintenance risks; natural gas prices and supply; economic conditions; weather and seasonality; interest rates; changes in tax legislation; derivative instruments and hedging; risks related to Terasen Gas (Vancouver Island) Inc.; capital resources; environment; insurance; licences and permits; energy prices and the cessation of the Niagara Exchange Agreement; loss of service area; First Nations Lands; counterparty risk; labour relations; human resources; and liquidity risk. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in the MD&A for the year ended December 31, 2007.

All forward-looking information in the MD&A is qualified by its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

A discussion of the financial condition and results of operations for the fourth quarter of 2007 is contained in the Corporation's Interim MD&A for the 3 and 12 months ended December 31, 2007 dated and filed on SEDAR at www.sedar.com on February 7, 2008.



Barry Perry, VP, Finance and CFO, Fortis Inc.

Management Discussion and Analysis

Corporate Overview and Strategy

Fortis is the largest investor-owned distribution utility company in Canada, serving almost 2,000,000 gas and electricity customers. Its regulated holdings include a natural gas distribution utility in British Columbia and electric distribution utilities in five Canadian provinces and three Caribbean countries. Fortis owns non-regulated generation assets across Canada and in Belize and Upper New York State. It also owns hotels and commercial real estate across Canada. In 2007, the Corporation's electricity distribution systems met a combined peak electricity demand of approximately 5,700 megawatts ("MW") and its gas distribution system met a peak day demand of 1,360 terajoules ("TJ").

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, the Corporation pursues growth through acquisitions.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, and deliver gas and electricity safely and reliably to customers at reasonable rates. The Corporation's core business is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The reporting segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other. The earnings of the Corporation's regulated utilities are primarily determined under traditional cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates which factor into customer rate-setting mechanisms.

Fortis also holds investments in non-regulated generation assets, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets operate in three countries and have a combined generating capacity of 195 MW, mainly hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties to ensure standard operating practices, to enable leveraging of expertise across the various jurisdictions and to allow the pursuit of non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide for financial, tax and regulatory flexibility, and enhance shareholder return.

The Corporation's operating segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each operating segment operates as an autonomous unit, assumes profit and loss responsibility, and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 825,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 91,200 residential, commercial and industrial customers.



In addition to providing transmission and distribution (“T&D”) services to customers, TGI and TGI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI’s Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 residential and commercial customers.

Regulated Electric Utilities – Canadian

- a. *FortisAlberta*: FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving over 448,000 customers.
- b. *FortisBC*: Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 154,000 customers. FortisBC Inc. owns four hydroelectric generating plants with a combined capacity of 223 MW. During 2007, the entitlement capacity and energy output for a number of FortisBC Inc.’s hydroelectric generating units were optimized as a result of past turbine and generator upgrade projects. Entitlement capacity was rebalanced from 235 MW to 223 MW and energy output increased by 11,000 megawatt hours (“MWh”) as a result of negotiated adjustments to the Canal Plant Agreement with BC Hydro. Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust (“CPC/CBT”), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna. FortisBC’s assets also include the regulated electric utility formerly operated as Princeton Light and Power Company, Limited.
- c. *Newfoundland Power*: Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 232,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 96 MW is hydroelectric generation.
- d. *Maritime Electric*: Maritime Electric is the principal distributor of electricity on Prince Edward Island (“PEI”), serving approximately 72,000 customers. Maritime Electric also maintains on-island generating facilities with a combined capacity of 150 MW.
- e. *FortisOntario*: FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario operations include Canadian Niagara Power Inc. (“Canadian Niagara Power”) and Cornwall Street Railway, Light and Power Company, Limited (“Cornwall Electric”). Included in Canadian Niagara Power’s accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies formed in 2000, serving more than 27,000 customers.

Regulated Electric Utilities – Caribbean

- a. *Belize Electricity*: Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 73,000 customers. The Company has an installed generating capacity of 36 MW. Fortis holds a 70.1 per cent controlling interest in Belize Electricity.
- b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 23,000 customers. The Company has an installed generating capacity of approximately 137 MW. On November 7, 2006, Fortis acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U) and has an April 30th fiscal year end. Caribbean Utilities’ balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities’ financial statements on a two-month lag basis and, accordingly, has consolidated Caribbean Utilities’ October 31, 2007 balance sheet, and statements of earnings and cash flows for the 12-month period ended October 31, 2007 with the Corporation’s December 31, 2007 consolidated financial statements. During 2006, the statement of earnings of Fortis reflected the Corporation’s approximate 37 per cent ownership interest in Caribbean Utilities, previously accounted for on an equity basis, on a two-month lag.

Management Discussion and Analysis

- c. *PPC Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. (collectively referred to as Fortis Turks and Caicos):* Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands, serving more than 8,700 customers. The Company has a combined diesel-fired generating capacity of 48 MW. Fortis Turks and Caicos was acquired by Fortis, through a wholly owned subsidiary, on August 28, 2006.

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

- a. *Belize:* Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the electricity output is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. Hydroelectric generation operations in Belize are conducted through the Corporation's wholly owned indirect subsidiary, Belize Electric Company Limited ("BECOL"), under a Franchise Agreement with the Government of Belize.
- b. *Ontario:* Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. Non-regulated generation operations in Ontario are conducted through FortisOntario Inc. and Fortis Properties. On January 1, 2006, the former FortisOntario Generation Corporation was amalgamated with CNE Energy Inc. and, effective January 1, 2007, CNE Energy Inc. was amalgamated with Fortis Properties.
- c. *Central Newfoundland:* Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary, Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Since the amalgamation of CNE Energy Inc. with Fortis Properties on January 1, 2007, Fortis Properties has held directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033.
- d. *British Columbia:* Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013. Hydroelectric generation operations in British Columbia are conducted through the Walden Power Partnership, a wholly owned partnership of FortisBC Inc.
- e. *Upper New York State:* Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the US Federal Energy Regulatory Commission. Hydroelectric generation operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary, FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 19 hotels with more than 3,500 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any other reportable segment. Included in this segment are finance charges including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; foreign exchange gains or losses; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes. Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. Terasen was acquired by Fortis on May 17, 2007.

Financial Highlights

For the Years Ended December 31st

	2007	2006	Variance (%)
Net earnings applicable to common shares (\$ millions)	193	147	31.3
Basic earnings per common share (\$)	1.40	1.42	(1.4)
Diluted earnings per common share (\$)	1.32	1.37	(3.6)
Weighted average number of common shares outstanding (millions)	137.6	103.6	32.8
Revenue and equity income (\$ millions)	2,718	1,472	84.6
Dividends paid per common share (\$)	0.82	0.67	22.4
Return on average common shareholders' equity (%)	9.99	11.87	(15.8)
Total assets (\$ millions)	10,273	5,441	88.8
Cash flow from operating activities (\$ millions)	373	263	41.8

Acquisitions: On May 17, 2007, Fortis completed the acquisition of all of the issued and outstanding common shares of Terasen, formerly a wholly owned subsidiary of Kinder Morgan, Inc. for aggregate consideration of \$3.7 billion, including the assumption of approximately \$2.4 billion of consolidated debt. Terasen owns and operates a gas distribution business carried on by TGI, TGV and TGWI. Terasen is the principal natural gas distributor in British Columbia, serving over 918,000 customers or 96 per cent of gas users in the province. The acquisition did not include the petroleum transportation assets of Kinder Morgan Canada (formerly Terasen Pipelines), which are comprised primarily of refined and crude oil pipelines.

A significant portion of the net cash purchase price of Terasen was satisfied with the net proceeds of the public offering of Subscription Receipts completed by Fortis on March 15, 2007. Fortis issued 44,275,000 Subscription Receipts for gross proceeds of approximately \$1.15 billion. Upon closing of the acquisition on May 17, 2007, each Subscription Receipt was automatically exchanged, without payment of additional consideration, for one Common Share of Fortis. Each Subscription Receipt holder also received a cash payment of 21 cents per Subscription Receipt, which was an amount equal to the dividend declared per Common Share of Fortis to holders of record as of May 4, 2007. The remaining net cash purchase price was financed, on an interim basis, by drawing \$125 million on the Corporation's existing credit facility.

On August 1, 2007, Fortis Properties purchased the Delta Regina, comprising the Delta Regina Hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage, in Regina, Saskatchewan for an aggregate cash purchase price of approximately \$50 million.

On November 7, 2006, Fortis acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities for approximately \$56 million (US\$49 million), and now owns approximately 54 per cent of the Company.

On November 1, 2006, Fortis Properties purchased four hotels in Alberta and British Columbia for an aggregate cash purchase price of approximately \$52 million. The four hotels acquired were the Holiday Inn Express and Suites, and Best Western, in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia.

On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all of the issued and outstanding shares of Fortis Turks and Caicos for cash consideration of approximately \$98 million (US\$88 million). Fortis Turks and Caicos serves more than 8,700 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands pursuant to 50-year licences that expire in 2036 and 2037.

Key Trends and Risks: The acquisition of Terasen improves the risk profile of Fortis by providing the Corporation with a more economically diverse portfolio of assets and earnings. The expansion into natural gas added a new business segment, doubled the regulated rate base of Fortis to approximately \$6.3 billion and was complementary to the Corporation's proven core competencies in managing regulated electric distribution utilities. The distribution franchises of the Terasen Gas companies have a well-diversified, mature, principally residential customer base and operate in a service territory that is experiencing strong economic growth and includes substantially all of the service territory of FortisBC. The expansion into natural gas distribution provides Fortis with a platform for future growth in the regulated natural gas business in Canada and the United States.

Following the Terasen acquisition, a large proportion of the businesses of Fortis serve the high-growth economies of western Canada. At December 31, 2007, regulated utility assets comprised 92 per cent of total assets compared to 86 per cent at December 31, 2006. At December 31, 2007, regulated utility assets in Canada comprised 84 per cent of total assets compared to 71 per cent at December 31, 2006.

Management Discussion and Analysis

Over the past few years, declining long-term interest rates in Canada have negatively impacted the allowed rate of return on common shareholders' equity ("ROE") used to set customer rates at each of the Corporation's four largest regulated utilities. However, due to a modest increase in long-term Canada bond rates during 2007, the allowed ROEs at TGI, FortisAlberta, FortisBC and Newfoundland Power were increased, for the purpose of setting customer rates in 2008, in accordance with the automatic adjustment formulas approved by the respective regulators. The chart below highlights the trend in the regulator-allowed ROEs at the above named utilities:

Regulator-Allowed ROE

(%)	2005	2006	2007	2008
TGI	9.03	8.80	8.37	8.62
FortisAlberta	9.50	8.93	8.51	8.75
FortisBC	9.43	9.20	8.77	9.02
Newfoundland Power	9.24	9.24	8.60	8.95

The impact on the Corporation's earnings of lower allowed ROEs was largely offset by increased rate bases and energy sales and the realization of operating cost efficiencies.

Economic growth in the province of Alberta has been robust, translating into strong customer and energy sales growth in FortisAlberta's service territory. This service territory includes environs of Calgary and Edmonton and includes the corridor between these cities. A healthy British Columbia provincial economy and population growth in the Okanagan region have favourably impacted customer and sales growth at FortisBC over the past few years. As a result, organic earnings growth derived from investment in utility infrastructure at the Corporation's Canadian regulated electric utilities is expected to be primarily driven by FortisAlberta and FortisBC. The Corporation's other Canadian regulated electric utilities – Newfoundland Power, Maritime Electric and FortisOntario – operate in more mature, stable environments, resulting in slower earnings growth.

With the acquisition of Terasen, regulated assets in the Caribbean region, as a percentage of total regulated assets, have decreased from 18 per cent at December 31, 2006 to 8 per cent at December 31, 2007. The regulated rate of return on rate base assets ("ROA") achieved in the Caribbean is higher compared to that achieved in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors and weather conditions. The Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential hurricane damage and related business interruption.

The key business risk to Fortis is regulatory risk. Except for the Terasen Gas companies and FortisBC, the Corporation's other utilities are regulated by different regulatory authorities. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been positive. In late 2007 and early 2008, regulator-approved negotiated settlement agreements were reached at FortisBC and Newfoundland Power for 2008 electricity rates and at FortisAlberta for 2008 and 2009 electricity rates. Achieving regulator-approved negotiated settlement agreements has eliminated the cost of full-scale public hearing processes. In December 2007, an agreement in principle ("AIP") was reached between Caribbean Utilities and the Government of the Cayman Islands on the terms of a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year T&D licence. The new licences are expected to be issued during the first half of 2008. In December 2007, regulatory amendments were enacted in Belize which settled outstanding matters associated with the regulator's decision concerning Belize Electricity's 2007/2008 electricity rates. In January 2008, Maritime Electric received regulatory approval for 2008 electricity rates. Although the potential receipt of an adverse regulatory decision may materially affect the ability of any utility to recover the cost of providing its services and achieve a reasonable rate of return, the impact on the Corporation as a whole is lessened due to the geographic and regulatory diversity of the Corporation's operations. For a complete discussion of regulatory activity and decisions and the Corporation's business risks, see the "Regulatory Highlights" and "Business Risk Management" sections of this MD&A.

Common share dividend payments increased to 82 cents per common share in 2007. A 19 per cent increase in the quarterly common share dividend to 25 cents from 21 cents, effective for the first quarter of 2008, extends the Corporation's record of annual common share dividend increases to 35 consecutive years, the longest record of any public corporation in Canada. Growth in earnings has enabled Fortis to increase its quarterly common share dividend 92 per cent since 2003.

Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of \$193 million in 2007, a 31.3 per cent increase over earnings of \$147 million last year. Basic earnings per common share were \$1.40 in 2007 compared to \$1.42 last year.

The growth in overall earnings was primarily attributable to the acquisition of Terasen in May 2007, but also reflected the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes.

The seasonality of earnings of the Terasen Gas companies, combined with the impact of a \$1.15 billion common share issue to fund a substantial portion of the cash purchase price of Terasen, diluted basic earnings per common share by 7 cents in 2007.

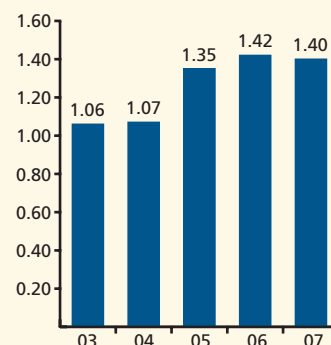
Revenue and Equity Income: Revenue and equity income increased almost 85 per cent to approximately \$2.72 billion from approximately \$1.47 billion last year. Revenue of \$905 million from the Terasen Gas companies, from the date of acquisition, was the main driver of the increase. The remainder of the increase was driven by Caribbean Utilities, Newfoundland Power, Fortis Properties and Fortis Turks and Caicos. Due to the increase in the Corporation's ownership in Caribbean Utilities to an approximate 54 per cent controlling interest in November 2006, Fortis has been consolidating Caribbean Utilities' financial results since the first quarter of 2007. During 2006, the statement of earnings of Fortis reflected the Corporation's approximate 37 per cent interest in Caribbean Utilities, previously accounted for on an equity basis. The increase in revenue at Newfoundland Power was driven by the flow through of higher purchased power costs, and the increase in revenue at Fortis Properties was primarily due to expanded hospitality operations in western Canada. The increase in revenue at Fortis Turks and Caicos was due to the first full year of ownership by Fortis.

Dividends: Dividends paid per common share increased to 82 cents in 2007 from 67 cents last year. On June 1, 2007, Fortis increased its quarterly common share dividend paid to 21 cents from 19 cents. Commencing with the first quarter dividend paid on March 1, 2008, Fortis increased its quarterly common share dividend 19 per cent to 25 cents per common share from 21 cents. The Corporation's dividend payout ratio was 58.6 per cent in 2007 compared to 47.2 per cent last year.

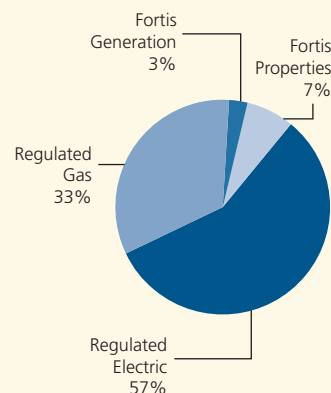
Return on Average Common Shareholders' Equity: Return on average common shareholders' equity was 10.0 per cent in 2007 compared to 11.9 per cent last year. The decrease reflected the impact of a lower ROE in 2007 at each of the Corporation's three largest electric utilities and the part-year ownership and seasonality of earnings of the Terasen Gas companies.

Asset Growth: Total assets increased almost 89 per cent to approximately \$10.27 billion at year-end 2007 from \$5.44 billion at year-end 2006, driven by the acquisition of Terasen. Of the approximate \$4.8 billion increase in total assets year over year, approximately \$4.5 billion, including goodwill of \$907 million, related to Terasen. The remaining increase in assets was primarily due to the Corporation's continued investment in electricity systems, driven by the capital expenditure programs at FortisAlberta and FortisBC, and the acquisition of the Delta Regina, partially offset by the unfavourable impact of foreign exchange associated with translation of foreign currency-denominated assets.

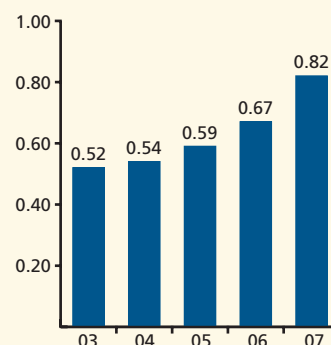
Basic Earnings per Common Share (\$)



Total Revenue (year ended December 31, 2007)

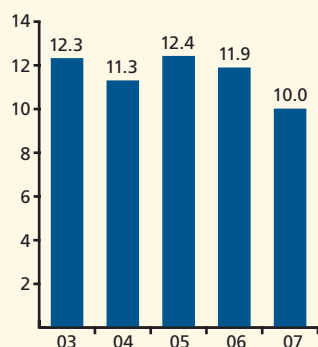


Dividends Paid per Common Share (\$)

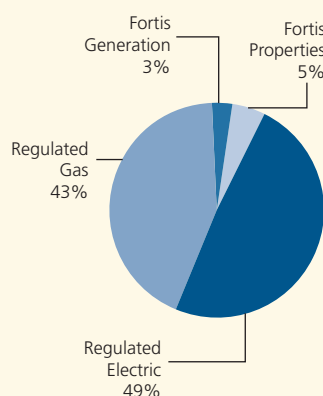


Management Discussion and Analysis

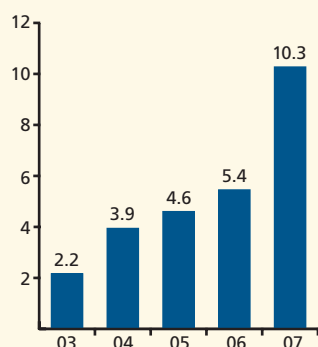
Return on Average Common Shareholders' Equity (%)



Total Assets
(as at December 31, 2007)



Total Assets (\$ billions)
(as at December 31st)



Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was \$373 million in 2007, 41.8 per cent higher than \$263 million last year. The increase in cash flow from operating activities, after working capital adjustments, was driven by FortisAlberta, Caribbean Utilities and FortisBC, partially offset by cash used in operating activities at the Terasen Gas companies.

2007 Capital Expenditures: During 2007, consolidated utility capital expenditures, before customer contributions ("gross utility capital expenditures"), were \$790 million, including \$120 million related to the Terasen Gas companies from the date of acquisition. Total capital investment at FortisAlberta and FortisBC during 2007 was approximately \$432 million, representing approximately 55 per cent of total gross utility capital expenditures. Much of this capital investment was driven by robust customer growth and the need to enhance the reliability of electricity systems.

Financings: During 2007, Fortis and its subsidiaries raised approximately \$2.1 billion of capital from a combination of common share and long-term debt issuances. In January 2007, 5.17 million Common Shares were publicly offered for gross proceeds of approximately \$150 million. The proceeds were primarily used to repay existing indebtedness incurred under the Corporation's committed credit facilities, principally to fund a portion of acquisitions in 2006; to support capital expenditure programs of the Corporation's regulated electric utilities in western Canada; and for general corporate purposes. In May 2007, the Corporation publicly issued 44.3 million Common Shares for gross proceeds of approximately \$1.15 billion, upon conversion of Subscription Receipts that were initially issued in March 2007, to finance a significant portion of the net cash purchase price of Terasen. In September 2007, Fortis privately placed 30-year US\$200 million 6.60% unsecured notes, the proceeds of which were used to repay existing indebtedness previously borrowed under the Corporation's committed credit facility associated with the Terasen acquisition, and for general corporate purposes. At the subsidiary level, FortisAlberta issued 40-year \$110 million 4.99% unsecured debentures in January 2007; FortisBC issued 40-year \$105 million 5.90% unsecured debentures in July 2007; Newfoundland Power issued 30-year \$70 million 5.901% first mortgage sinking fund bonds in August 2007; Caribbean Utilities privately placed 15-year US\$40 million 5.65% unsecured notes in total in June and November 2007; and TGI issued 30-year \$250 million 6.00% unsecured debentures in October 2007. Proceeds from the long-term debt issuances at the electric utilities were primarily used to repay indebtedness previously borrowed under their respective committed credit facilities incurred in support of capital spending. The proceeds from the issuance of \$250 million unsecured debentures by TGI were used to refinance \$250 million of existing debt that matured in October 2007. Investor confidence in the growth strategy of Fortis resulted in the execution of the above financings at attractive rates and terms.

Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings

Years Ended December 31st

(\$ millions)

	2007	2006	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies ⁽¹⁾	50	–	50
Regulated Electric Utilities – Canadian			
FortisAlberta	48	42	6
FortisBC	31	27	4
Newfoundland Power	30	30	–
Other Canadian ⁽²⁾	16	14	2
	125	113	12
Regulated Electric Utilities – Caribbean⁽³⁾	31	23	8
Non-Regulated – Fortis Generation	24	27	(3)
Non-Regulated – Fortis Properties⁽⁴⁾	24	19	5
Corporate and Other⁽⁵⁾	(61)	(35)	(26)
Net Earnings Applicable to Common Shares	193	147	46

⁽¹⁾ Financial results are from May 17, 2007, the date of acquisition.

⁽²⁾ Includes Maritime Electric and FortisOntario

⁽³⁾ Includes Belize Electricity, Caribbean Utilities, and Fortis Turks and Caicos acquired on August 28, 2006. Results for 2007 reflect the consolidation of Caribbean Utilities' financial statements on a two-month lag basis. Results for 2006 reflect the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities accounted for on an equity basis on a two-month lag.

⁽⁴⁾ Includes the results of Delta Regina from August 1, 2007, the date of acquisition

⁽⁵⁾ Includes net corporate expenses and, from May 17, 2007, the net expenses of non-regulated Terasen corporate-related activities and Terasen's 30 per cent ownership interest in CWLP

REGULATED UTILITIES

The Corporation's primary business is regulated utilities. The regulated earnings in Canada and the Caribbean represented approximately 81 per cent of the Corporation's earnings from its operating segments in 2007 (2006 – 75 per cent). Total regulated assets represented 92 per cent of the Corporation's total assets as at December 31, 2007 (December 31, 2006 – 86 per cent).

Regulated Gas Utilities – Canadian

Terasen Gas Companies

Financial Highlights

Year Ended December 31st ⁽¹⁾

	2007
Gas Volumes (TJ)	118,309
(\$ millions)	
Revenue	905
Energy Supply Costs	559
Operating Expenses	150
Amortization	58
Finance Charges	80
Gain on Sale of Property	(8)
Corporate Taxes	16
Earnings	50

⁽¹⁾ Data is from May 17, 2007, the date of acquisition.

Management Discussion and Analysis

On May 17, 2007, Fortis acquired all of the issued and outstanding shares of Terasen. Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI. Terasen is the principal distributor of natural gas in British Columbia, serving over 918,000 customers or 96 per cent of gas users in the province. TGI provides gas distribution services to a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia. TGVI owns a combined gas distribution and transmission system serving customers along the Sunshine Coast and in various communities on Vancouver Island, including Victoria and surrounding areas. TGWI provides propane distribution services to approximately 2,400 customers in the Whistler area.

Earnings: The Terasen Gas companies reported \$50 million in earnings from the date of acquisition on May 17, 2007. Seasonality materially impacts the earnings of the Terasen Gas companies as a major portion of the gas distributed is ultimately used for space heating. Virtually all of the earnings of the Terasen Gas companies are generated in the first and fourth quarters. Performance was consistent with that expected to be achieved by the Terasen Gas companies during the period and with operating performance achieved during the same period last year. Results during the period included a \$7 million after-tax gain on the sale of surplus land.

As a result of the operation of British Columbia Utilities Commission ("BCUC")-approved regulatory deferral mechanisms, changes in consumption levels and the commodity cost of natural gas do not materially impact the earnings of the Terasen Gas companies. These mechanisms accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers and also accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. Additionally, the Terasen Gas companies use a BCUC-approved interest rate deferral account to absorb interest rate fluctuations, thereby effectively fixing the rate of interest on short-term and variable-rate credit-facility borrowings.

Gas Volumes: Gas volumes from the date of acquisition were 118,309 TJ. On an annual basis, gas volumes were 220,977 TJ, up 5.7 per cent from 209,013 TJ in 2006. The increase in annual gas volumes was due to cooler weather and growth in the number of customers. Increased volumes result in both higher revenue and natural gas costs and generally do not have a material impact on the earnings of the Terasen Gas companies.

Net customer additions at TGI were 9,939 during 2007 compared to 10,289 net customer additions during 2006. Though 2007 was another strong year for housing starts in British Columbia, adverse weather conditions slowed construction activity late in the year. In addition, growth in multi-family housing impacted net additions as natural gas usage is less prevalent in this type of dwelling. Net customer additions at TGVI were 3,922 during 2007 compared to 4,120 net customer additions during 2006.

Following the acquisition of Terasen by the Corporation, Standard & Poor's ("S&P") raised its unsolicited long-term corporate credit and senior unsecured debt credit ratings on TGI to 'A' from 'BBB' on June 19, 2007.

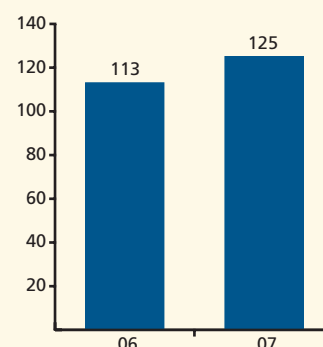
Outlook: TGI's allowed ROE for 2008 has been set at 8.62 per cent, up from 8.37 per cent in 2007. TGVI's allowed ROE for 2008 has been set at 9.32 per cent, up from 9.07 per cent in 2007.

A summary of the forecast gross capital expenditures for 2008 for the Terasen Gas companies is provided under the heading "Capital Program".

Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings during 2007 were \$125 million (2006 – \$113 million), which represented approximately 61 per cent (2006 – 83 per cent) of the Corporation's total regulated earnings. Regulated Electric Utilities – Canadian assets were \$4.2 billion as at December 31, 2007 (December 31, 2006 – \$3.9 billion), which represented approximately 44 per cent of the Corporation's total regulated assets as at December 31, 2007 (December 31, 2006 – 82 per cent).

Regulated Electric Utilities – Canadian Earnings (\$ millions)



FortisAlberta

Financial Highlights

Years Ended December 31st

	2007	2006	Variance
Energy Deliveries (GWh)	15,378	14,851	527
(\$ millions)			
Revenue	270	251	19
Operating Expenses	122	115	7
Amortization	75	69	6
Finance Charges	36	30	6
Corporate Tax Recovery	(11)	(5)	(6)
Earnings	48	42	6

Earnings: FortisAlberta's earnings in 2007 were \$6 million higher than last year, primarily due to higher revenue associated with customer growth, and increased corporate income tax recovery, partially offset by higher operating expenses, amortization costs and finance charges.

Energy Deliveries: Energy deliveries increased 527 gigawatt hours ("GWh"), or 3.5 per cent, year over year due to increased energy demand related to customer growth. The Company added approximately 18,000 customers during the year, bringing the total number of customers at FortisAlberta to more than 448,000.

Revenue: Revenue in 2007 was \$19 million higher than last year due to an increase of \$11 million resulting from customer growth and the 0.7 per cent increase in distribution rates billed to customers, effective January 1, 2007; an increase of \$3 million resulting from differences in the impact of various distribution revenue deferrals; increased franchise fee revenue of \$1 million; higher net transmission revenue of \$1 million largely related to increased energy deliveries, number of customers and Alberta Electric System Operator ("AESO") billing and deferral adjustments; and increased miscellaneous revenue of \$3 million. The increase in miscellaneous revenue was primarily due to penalties associated with early termination of distribution service by customers, increased third-party contract work and interest earned on AESO Charges Deferral Accounts.

Expenses: Operating expenses in 2007 were \$7 million higher than last year, primarily due to higher labour, employee-benefit and contracted manpower costs and material purchases, partially offset by increased amounts charged to capital projects.

Amortization costs in 2007 were \$6 million higher than last year, due to an increase in capital assets driven by load growth, and upgrades and replacements of assets within the Company's service territory, partially offset by amortization of increased customer contributions.

Finance charges in 2007 were \$6 million higher than last year, primarily due to increased debt levels to finance capital spending. On January 3, 2007, FortisAlberta issued \$110 million 4.99% senior unsecured debentures, maturing January 3, 2047. On April 21, 2006, FortisAlberta issued \$100 million 5.40% senior unsecured debentures, maturing April 21, 2036. The net proceeds of the debenture issues were largely used to repay existing credit-facility borrowings that were incurred primarily to fund capital expenditures.

Management Discussion and Analysis

Corporate tax recovery in 2007 was \$6 million higher than last year, primarily due to a future income tax recovery in 2007 resulting from the reduction of AESO deferral amounts upon which future income tax is calculated, partially offset by higher current income taxes resulting from a decrease in deductions taken for income tax purposes compared to amounts taken for accounting purposes in 2007 as compared to 2006.

Outlook: FortisAlberta's allowed ROE for 2008 has been set at 8.75 per cent, up from 8.51 per cent in 2007. In February 2008, FortisAlberta received regulatory approval of the Negotiated Settlement Agreement ("NSA") pertaining to the Company's 2008 and 2009 electricity rates. The approved NSA provides for distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009.

A summary of FortisAlberta's forecast gross capital expenditures for 2008 is provided under the heading "Capital Program".

FortisBC

Financial Highlights

Years Ended December 31 st	2007	2006	Variance
Electricity Sales (GWh)	3,091	3,038	53
(\$ millions)			
Revenue	229	216	13
Energy Supply Costs	67	68	(1)
Operating Expenses	69	63	6
Amortization	31	28	3
Finance Charges	26	23	3
Corporate Taxes	5	7	(2)
Earnings	31	27	4

Earnings: FortisBC's earnings in 2007 were \$4 million higher than last year, driven by increased electricity rates, higher electricity sales and lower energy supply costs and corporate taxes, partially offset by increased operating expenses, amortization costs and finance charges.

Electricity Sales: Electricity sales increased 53 GWh, or 1.7 per cent, year over year. The favourable impact on electricity sales of a reduction in the estimate of electricity system losses and growth in the number of customers in the residential and general service sectors more than offset the impact of reduced industrial loads associated with a plant optimization by a significant industrial customer. During the first quarter of 2007, an analysis of electricity system losses resulted in a reduction of the estimate of system losses, effective January 1, 2007. The reduction in the system losses reflects efficiency improvements arising from the Company's ongoing capital program of upgrading and replacing generation and T&D systems, as well as the refinement of the process for estimating system losses.

Revenue: Revenue in 2007 was \$13 million higher than last year, primarily due to a 1.2 per cent increase in electricity rates, effective January 1, 2007; an incremental 2.1 per cent increase in electricity rates, effective April 1, 2007, including the accrual during the first quarter of 2007 of the 2.1 per cent increase in electricity rates to be collected from customers in 2008; higher revenue contributions from non-regulated operating, maintenance and management services; increased electricity sales for the year due to the reasons described above; and a decrease in performance-based rate-setting ("PBR") incentive adjustments owing to customers.

Expenses: Energy supply costs in 2007 were \$1 million lower than last year. Despite having a higher proportion of purchased energy versus energy generated from Company-owned hydroelectric generating plants during 2007, energy supply costs decreased due to lower average power purchase prices.

Operating expenses in 2007 were \$6 million higher than last year. The increase was driven by higher operating expenses associated with non-regulated operating, maintenance and management services; general inflationary cost increases; higher labour costs; an increase in the allowance for doubtful accounts associated with forestry-sector customers; and increased property taxes. The increase in operating expenses was partially offset by lower wheeling and water fees and the impact of increased capitalized overhead costs.

Amortization costs in 2007 were \$3 million higher than last year, due to an increase in the capital assets of FortisBC related to its capital spending program.

Finance charges in 2007 were \$3 million higher than last year, driven by increased borrowings to finance the Company's capital spending program. On July 4, 2007, FortisBC issued \$105 million 5.90% senior unsecured debentures, maturing July 4, 2047. The net proceeds of the debenture issue were used largely to repay existing credit-facility borrowings that were incurred primarily to fund capital expenditures.

On June 21, 2007, Moody's Investors Service upgraded the credit rating on FortisBC's senior unsecured debt to 'Baa2, Stable Outlook' from 'Baa3, Stable Outlook'.

Corporate taxes in 2007 were \$2 million lower than last year, primarily due to higher deductions taken for corporate income tax purposes compared to amounts taken for accounting purposes, partially offset by higher earnings before corporate taxes.

Outlook: FortisBC's allowed ROE for 2008 has been set at 9.02 per cent, up from 8.77 per cent in 2007. In December 2007, FortisBC received regulatory approval of the NSA pertaining to the Company's 2008 electricity rates, resulting in an increase in electricity rates of 2.9 per cent effective January 1, 2008.

In the second half of 2008, the Company intends on filing with the BCUC a 2009 and 2010 Capital Plan and a 2009 Revenue Requirements Application.

A summary of FortisBC's forecast gross capital expenditures for 2008 is provided under the heading "Capital Program".

Newfoundland Power

Financial Highlights

Years Ended December 31 st	2007	2006	Variance
Electricity Sales (GWh)	5,093	4,995	98
(\$ millions)			
Revenue	490	421	69
Energy Supply Costs	327	256	71
Operating Expenses	53	54	(1)
Amortization	34	33	1
Finance Charges	33	33	–
Corporate Taxes	12	14	(2)
Non-Controlling Interest	1	1	–
Earnings	30	30	–

Earnings: Newfoundland Power's 2007 earnings of \$30 million were comparable to last year. The impact of increased electricity sales was largely offset by the impact of reduced electricity rates due to a reduction in the allowed ROE for 2007.

Electricity Sales: Electricity sales increased 98 GWh, or 2.0 per cent, year over year, primarily due to customer growth and an increase in average consumption.

Revenue: Revenue in 2007 was \$69 million higher than last year. The increase was primarily due to the flow through of higher purchased power costs from Newfoundland Hydro, effective January 1, 2007, and increased electricity sales, partially offset by a decrease in electricity rates, effective January 1, 2007, due to a lower allowed ROE for 2007.

Expenses: Energy supply costs in 2007 were \$71 million higher than last year, primarily due to the flow through of higher purchased power costs from Newfoundland Hydro, effective January 1, 2007, and increased electricity sales.

Operating expenses in 2007 were \$1 million lower than last year. The decrease was primarily due to lower pension costs, reflecting improved returns on higher levels of plan assets attributable to pension funding, and the conclusion, in March 2007, of the amortization of retirement allowances associated with a 2005 Early Retirement Program. The decrease in operating expenses was partially offset by higher labour costs, reflecting both normal wage increases and costs incurred to repair major storm damage to certain distribution systems in December 2007.

Management Discussion and Analysis

Amortization costs in 2007 were \$1 million higher than last year, primarily due to the continued investment in capital assets.

Finance charges in 2007 were comparable to last year. On August 17, 2007, Newfoundland Power issued \$70 million 5.901% first mortgage sinking fund bonds, maturing August 17, 2037. The net proceeds were used to repay existing credit-facility borrowings, incurred principally to fund capital expenditures, and to retire \$31.5 million of maturing 11.875% bonds.

Corporate taxes in 2007 were \$2 million lower than last year. The decrease reflected lower earnings before corporate taxes and higher deductions taken for corporate income tax purposes compared to deductions taken for accounting purposes. The higher tax deductions largely related to increased capital cost allowance driven by capital expenditures associated with the Company's Rattling Brook hydroelectric plant during 2007.

Outlook: Newfoundland Power's allowed ROE for 2008 has been set at 8.95 per cent, up from 8.60 per cent in 2007. In December 2007, Newfoundland Power received regulatory approval of the NSA pertaining to 2008 electricity rates, resulting in an average increase in electricity rates of 2.8 per cent effective January 1, 2008.

As a result of a new purchased-power rate structure, effective January 1, 2007, Newfoundland Power paid more, on average, for each kilowatt hour ("kWh") of purchased power in the winter months and less, on average, for each kWh of purchased power in the summer months in 2007 compared to 2006. For 2007, quarterly earnings were not impacted by this change as the Company recorded purchased power based on the forecast annual unit cost per kWh with quarterly variances deferred to a regulatory deferral account. Beginning on January 1, 2008, this regulated account is no longer in effect. As a result, quarterly earnings in 2008 will reflect a seasonal shift from that experienced in 2007. Earnings are expected to be lower in the first and fourth quarters and higher in the second and third quarters compared to the same periods in 2007.

A summary of Newfoundland Power's forecast gross capital expenditures for 2008 is provided under the heading "Capital Program".

Other Canadian Electric Utilities⁽¹⁾

Financial Highlights

Years Ended December 31 st	2007	2006	Variance
Electricity Sales (GWh)			
Maritime Electric	1,035	999	36
FortisOntario	1,174	1,169	5
Total	2,209	2,168	41
(\$ millions)			
Revenue	263	252	11
Energy Supply Costs	174	171	3
Operating Expenses	29	28	1
Amortization	17	15	2
Finance Charges	17	15	2
Corporate Taxes	10	9	1
Earnings	16	14	2

⁽¹⁾ Includes Maritime Electric and FortisOntario

Earnings: Earnings from Other Canadian Electric Utilities in 2007 were \$2 million higher than last year, driven by a one-time \$3 million (\$2 million after-tax) gain at FortisOntario, related to a refund received as ordered by the regulator associated with an interconnection arrangement, and increased electricity sales and basic electricity rates, partially offset by higher operating expenses, amortization costs and finance charges.

Electricity Sales: Electricity sales increased 41 GWh, or 1.9 per cent, year over year. The increase was driven by higher average consumption due to cooler-than-normal weather conditions experienced on PEI and in Ontario and an increase in the number of customers at Maritime Electric, partially offset by the impact of the loss of a major industrial customer and a temporary shutdown of operations of an industrial customer in Ontario.

Revenue: Revenue in 2007 was \$11 million higher than last year, primarily due to increased electricity sales; the \$3 million refund received at FortisOntario; a 3.35 per cent increase in basic electricity rates at Maritime Electric, effective July 1, 2006; the impact of an increase in rates at FortisOntario associated with the flow through to customers of higher energy supply costs; and increases in basic distribution rates at FortisOntario in May 2006 and May 2007.

Expenses: Energy supply costs in 2007 were \$3 million higher than last year, driven by increased market energy prices paid at FortisOntario and increased electricity sales. At Maritime Electric, actual energy supply costs above or below the regulator-approved amount of 6.73 cents per kWh are deferred for future recovery from, or refund to, customers over a 12-month rolling period.

Operating expenses in 2007 were \$1 million higher than last year, driven by costs associated with an early retirement program at FortisOntario and higher insurance, regulatory and legal costs.

Amortization costs in 2007 were \$2 million higher than last year, primarily due to continued investment in capital assets.

Finance charges in 2007 were \$2 million higher than last year, due to borrowings required to finance capital spending and higher energy supply costs at Maritime Electric.

Corporate taxes in 2007 were \$1 million higher than last year, driven by higher earnings before corporate taxes, partially offset by higher deductions taken for corporate income tax purposes compared to deductions taken for accounting purposes.

Outlook: Maritime Electric's maximum allowed ROE for 2008 has been set at 10.00 per cent compared to 10.25 per cent in 2007. In January 2008, the Island Regulatory and Appeals Commission ("IRAC") approved a 1.8 per cent increase in basic customer rates, effective April 1, 2008.

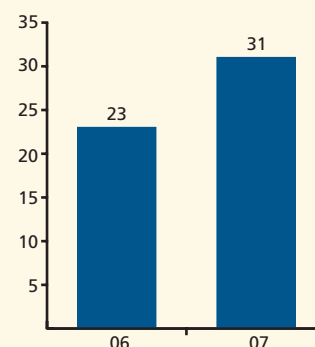
FortisOntario's allowed ROE for 2008 is 9.00 per cent, unchanged from 2007. In 2006, the Ontario Energy Board ("OEB") announced its multi-year electricity distribution rate-setting plan for the years 2007 through 2010. The plan maintains the current cost of capital and introduces an inflation measure coupled with a productivity factor for rate-setting purposes. Over the three-year period, distributors will be required, in three tranches, to submit a full cost-of-service application, which will result in the rebasing of distribution rates. In late 2008, Canadian Niagara Power is expecting to file for rate rebasing for 2009.

A summary of forecast gross capital expenditures for the Other Canadian Electric Utilities for 2008 is provided under the heading "Capital Program".

Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean during 2007 was \$31 million (2006 – \$23 million), which represented approximately 15 per cent (2006 – 17 per cent) of the Corporation's total regulated earnings. Regulated Electric Utilities – Caribbean assets were \$778 million as at December 31, 2007 (December 31, 2006 – \$828 million), which represented approximately 8 per cent of the Corporation's total regulated assets as at December 31, 2007 (December 31, 2006 – 18 per cent).

Regulated Electric Utilities – Caribbean Earnings (\$ millions)



Management Discussion and Analysis

Regulated Electric Utilities – Caribbean⁽¹⁾

Financial Highlights

Years Ended December 31 st	2007	2006 ⁽²⁾	Variance
Average US:CDN Exchange Rate⁽³⁾	1.07	1.13	(0.06)
Electricity Sales (GWh)			
Belize Electricity	382	360	22
Caribbean Utilities	527	485 ⁽⁴⁾	42
Fortis Turks and Caicos	145	125 ⁽⁴⁾	20
Total	1,054	970	84
(\$ millions)			
Revenue	307	101	206
Equity Income	–	10	(10)
Energy Supply Costs	169	57	112
Operating Expenses	49	13	36
Amortization	28	7	21
Finance Charges	15	5	10
Corporate Taxes	2	2	–
Non-Controlling Interest	13	4	9
Earnings	31	23	8

⁽¹⁾ Includes Belize Electricity, in which Fortis holds a 70.1 per cent controlling interest; Caribbean Utilities, in which Fortis holds an approximate 54 per cent controlling interest; and wholly owned Fortis Turks and Caicos.

⁽²⁾ Revenue and expenses for the 12 months ended December 31, 2006 do not include revenue and expenses related to Caribbean Utilities, as this utility was not consolidated in the financial statements of Fortis during this period. Revenue and expenses for the 12 months ended December 31, 2006 include revenue and expenses related to Fortis Turks and Caicos from August 28, 2006, the date of acquisition by Fortis. In 2006, equity income related to the Corporation's previous approximate 37 per cent investment interest in Caribbean Utilities accounted for on an equity basis.

⁽³⁾ The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ\$2.00 = US\$1.00. The reporting currency of Caribbean Utilities is the Cayman Island dollar, which is pegged to the US dollar at CI\$0.84 = US\$1.00. The reporting currency of Fortis Turks and Caicos is the US dollar.

⁽⁴⁾ Full year sales as reported by the utility.

On November 7, 2006, Fortis acquired an additional approximate 16 per cent interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities' balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities' financial statements on a two-month lag. During 2006, the statement of earnings of Fortis reflected the Corporation's previous approximate 37 per cent interest in Caribbean Utilities accounted for on an equity basis on a two-month lag. Caribbean Utilities has an April 30th fiscal year end and, therefore, the data presented above for 2007 and 2006 includes financial results for Caribbean Utilities for the 12-month periods ended October 31st.

Earnings: Earnings' contribution from Regulated Electric Utilities – Caribbean in 2007 was \$8 million higher than last year. The increase was driven by the first full year of earnings' contribution from Fortis Turks and Caicos, and higher electricity sales and lower finance charges at Belize Electricity, partially offset by the unfavourable impact of foreign currency translation. The impact of the increased investment in Caribbean Utilities to approximately 54 per cent was offset by the impact of lower earnings reported at Caribbean Utilities driven by a charge associated with the disposal of steam-turbine assets and higher operating expenses. The charge on disposal of the steam-turbine assets reduced earnings of Fortis by approximately \$2 million in 2007. Earnings' contribution from Regulated Electric Utilities – Caribbean was tempered by the \$2 million unfavourable impact of foreign exchange associated with translation of foreign currency-denominated earnings, due to strengthening of the Canadian dollar against the US dollar. During 2007, the contribution to earnings by Caribbean Utilities, Belize Electricity and Fortis Turks and Caicos was \$9 million, \$12 million and \$10 million, respectively.

Electricity Sales: Total electricity sales reported by Regulated Electric Utilities – Caribbean increased 84 GWh, or 8.7 per cent, year over year. The increase was primarily due to higher demand, driven by customer growth, as strong local economies fuelled new residential and commercial construction. Growth in electricity sales reported at Fortis Turks and Caicos was led by large hotels; however, the rate applicable to this customer class is the lowest of all customer classes of Fortis Turks and Caicos. Significant projects



under construction on the Turks and Caicos Islands include a US\$68 million expansion of the Beaches Resort & Spa; the Seven Stars Luxury resort; the 255,870-square foot Emerald Point Condominium and Resort; and the 220,440-square foot Alexandra Resort and Residences. Commercial growth on Grand Cayman is being led by new developments, including the 60,000-square foot Bank of Butterfield building, expected to come on line in early 2008, and the 160,000-square foot Governor's Square shopping and office centre, the 89,000-square foot Caribbean Club condominium complex and the 500,000-square foot phase-one of Camana Bay, each of which came on line during 2007.

Revenue: In addition to the impact of consolidating Caribbean Utilities' financial results during 2007, revenue increased year over year due to the impact of the first full year of ownership of Fortis Turks and Caicos, electricity sales growth at Belize Electricity and Fortis Turks and Caicos, and a 3.7 per cent increase in the value-added component of customer rates, effective July 1, 2007, at Belize Electricity. The increase was partially offset by the impact of foreign currency translation.

Expenses: The increase in expenses in 2007 over 2006 was significantly impacted by the consolidation of Caribbean Utilities' financial results during 2007 and the impact of the first full year of ownership of Fortis Turks and Caicos, partially offset by the impact of foreign currency translation.

Operating expenses and amortization costs at Belize Electricity increased year over year, due to higher employee costs, new customer service and revenue loss reduction initiatives, and general increases in the cost of goods and services. Amortization costs increased due to continued investment in capital assets. Finance charges at Belize Electricity were lower than last year due to lower debt balances. In June 2006, proceeds from a share offering at Belize Electricity were used to repay certain trade payables and inter-company loans, and drawings on overdraft facilities incurred primarily to finance the high cost of power and fuel.

Operating expenses reported at Fortis Turks and Caicos in 2007 increased over last year, due to the impact of increased activity associated with a high-growth environment.

Caribbean Utilities' operating expenses consolidated in the financial results of the Corporation during 2007 were higher than operating expenses reported by Caribbean Utilities in 2006, driven by higher generation and T&D maintenance costs, and by operating expenses during the second quarter of 2006 being reduced by a \$1.4 million (US\$1.2 million) gain on disposal of assets associated with an insurance settlement. Additionally, during the first quarter of 2007, Regulated Electric Utilities – Caribbean operating expenses included a \$4.4 million (US\$3.7 million) charge on the disposal of Caribbean Utilities' steam-turbine assets. Caribbean Utilities' amortization costs consolidated in the financial results of the Corporation during 2007 were higher than amortization costs reported by Caribbean Utilities during 2006, due to continued investment in capital assets, including the addition of a new 16-MW diesel-fired generating unit commissioned in June 2007. The generating unit increased Caribbean Utilities' total installed generating capacity to approximately 137 MW.

Caribbean Utilities closed the US\$30 million first tranche of a US\$40 million 5.65% senior unsecured note offering in June 2007 and closed the second tranche of US\$10 million in November 2007. The senior unsecured notes are due June 1, 2022. The proceeds from the debt offering were used to repay debt and to finance capital expenditures.

During 2007, Fortis Turks and Caicos commissioned an additional 7 MW of owned generating capacity, bringing the combined generating capacity at Fortis Turks and Caicos to 48 MW at the end of the year. In May 2007, Fortis Turks and Caicos purchased four additional generating units with a combined capacity of 13 MW, which are expected to be installed and commissioned during 2008 and 2009. The additional capacity is intended to keep pace with strong customer growth.

Outlook: Strong electricity sales growth experienced by the Regulated Electric Utilities – Caribbean segment during 2007 is expected to continue in 2008.

During the first half of 2008, the Government of the Cayman Islands is expected to issue a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year T&D licence to Caribbean Utilities. Under the proposed new licences, customer rates will be set using an initial targeted ROA of 10 per cent, down from 15 per cent as permitted under the existing licence. Additional information on the impact of the proposed new licences is provided under the heading "Regulatory Highlights".

Management Discussion and Analysis

Electricity rates at Belize Electricity have been approved for the period from July 1, 2007 through June 30, 2008. While the value-added component of electricity rates has increased, average electricity rates remain unchanged.

A summary of forecast gross capital expenditures for the Regulated Electric Utilities – Caribbean segment for 2008 is provided under the heading “Capital Program”.

NON-REGULATED

Non-Regulated – Fortis Generation

Fortis Generation consists of the Corporation’s investment in non-regulated generation assets. The following table provides a summary of the Corporation’s non-regulated generation assets by location.

	Plants	Capacity (MW)
Belize	2	32
Ontario	8	88
Central Newfoundland	2	36
British Columbia	1	16
Upper New York State	4	23
Total	17	195

Financial Highlights

Years Ended December 31 st	2007	2006	Variance
Energy Sales (GWh)			
Belize	167	178	(11)
Ontario	707	722	(15)
Central Newfoundland	137	168	(31)
British Columbia	34	30	4
Upper New York State	77	105	(28)
Total	1,122	1,203	(81)
(\$ millions)			
Revenue	75	80	(5)
Energy Supply Costs	8	6	2
Operating Expenses	14	15	(1)
Amortization	10	11	(1)
Finance Charges	10	10	–
Corporate Taxes	8	8	–
Non-Controlling Interest	1	3	(2)
Earnings	24	27	(3)

Earnings: Earnings from Non-Regulated – Fortis Generation in 2007 were \$3 million lower than last year. The decrease was primarily due to decreased production due to lower rainfall, partially offset by higher average wholesale energy prices in Ontario and decreased operating expenses.

Energy Sales: Energy sales decreased 81 GWh, or 6.7 per cent, year over year. The decrease was primarily due to lower production as a result of lower rainfall in most of the operating regions; however, rainfall in 2006 was generally above normal levels. Production in Belize in 2007 and 2006 was above expected levels based on historical average rainfall. The decrease in energy sales was partially offset by the impact of a full year of operations of the Dolgeville plant in Upper New York State in 2007 compared to nine months of operation in 2006 as a result of a disruption of water supply due to flooding during that year.

Revenue: Revenue in 2007 was \$5 million lower than last year, driven by decreased production, partially offset by higher average wholesale energy prices in Ontario and the flow through of increased energy supply-related costs in central Newfoundland.

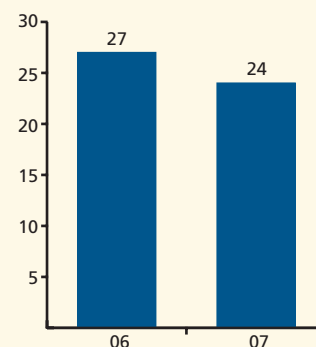
The average wholesale energy price per MWh in Ontario during 2007 was \$47.81 compared to \$46.38 last year. The increase in average wholesale energy prices in Ontario resulted in an increase in revenue in 2007 of approximately \$1 million compared to last year.

Expenses: Operating expenses in 2007 were \$1 million lower than last year, driven by the receipt of insurance proceeds in 2007 associated with costs expensed late in 2006 related to the flood at the Dolgeville plant and the reallocation of costs from non-regulated Ontario generation operations to regulated Ontario electricity operations.

Outlook: Construction of the 18-MW hydroelectric generating facility at Vaca on the Macal River in Belize commenced during 2007. The facility is expected to come into service late in 2009. Earnings' contribution from the Vaca facility is expected to partially offset a loss of earnings upon the expiration, in 2009, of the Niagara Exchange Agreement associated with the Rankine Generating Station in Ontario.

Further information on the Vaca hydroelectric facility and a summary of forecast non-regulated utility capital expenditures for 2008 is provided under the heading "Capital Program".

**Non-Regulated – Fortis
Generation Earnings (\$ millions)**



Non-Regulated – Fortis Properties

Fortis Properties consists of the Corporation's investment in non-regulated commercial real estate and hotel assets.

Financial Highlights

Years Ended December 31st

(\$ millions)

	2007	2006	Variance
Real Estate Revenue	59	55	4
Hospitality Revenue	132	108	24
Total Revenue	191	163	28
Operating Expenses	123	105	18
Amortization	14	12	2
Finance Charges	24	21	3
Gain on Sale of Property	–	(2)	2
Corporate Taxes	6	8	(2)
Earnings	24	19	5

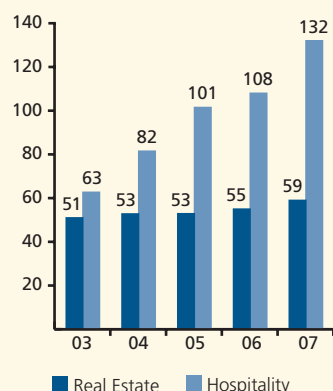
Earnings: Fortis Properties' earnings in 2007 were \$5 million higher than last year. Excluding a \$4 million favourable corporate tax adjustment in 2007 and excluding \$3 million associated with a favourable corporate tax adjustment and a gain on the sale of Days Inn Sydney in 2006, earnings in 2007 were \$4 million higher than last year, driven by expanded hospitality operations in western Canada.

On August 1, 2007, Fortis Properties purchased the Delta Regina in Saskatchewan for approximately \$50 million, including acquisition costs. Delta Regina is comprised of 274 hotel rooms, the Saskatchewan Trade and Convention Centre, 52,000 square feet of Class A commercial office space and a parking garage. On November 1, 2006, Fortis Properties purchased four hotels in Alberta and British Columbia for approximately \$52 million, including acquisition costs and assumed debt, increasing hospitality operations by 454 rooms.

Revenue: Real estate revenue in 2007 was \$4 million higher than last year, due to the expanded Blue Cross Centre in Moncton, revenue from the Delta Regina associated with real estate operations and growth experienced in all operating regions of the Company. The occupancy rate of the Real Estate Division was 96.8 per cent as at December 31, 2007, up from 94.9 per cent as at December 31, 2006, due to additional leasing in all operating regions of the Company.

Management Discussion and Analysis

Fortis Properties Revenue (\$ millions)



Hospitality revenue in 2007 was \$24 million higher than last year, \$23 million of which was due to growth in the Company's hospitality operations in western Canada, \$1 million of which was due to increased revenue earned from the expanded Ontario hotels and \$1 million of which was due to increased revenue earned from the Company's hospitality operations in Atlantic Canada. The increases were partially offset by the impact of the elimination of revenue following the sale of Days Inn Sydney in June 2006.

Revenue per available room ("REVPAR") in 2007 was \$79.31 compared to \$72.67 in 2006. The increase in REVPAR was primarily attributable to the addition of the four hotels in western Canada acquired on November 1, 2006 and the Delta Regina acquired on August 1, 2007.

Expenses: Operating expenses in 2007 were \$18 million higher than last year. The increase was primarily due to expanded operations and general inflationary cost pressures driven by the Company's hospitality operations in western Canada and the expanded Ontario hotels and Blue Cross Centre. The increase was partially offset by the elimination of operating expenses following the sale of Days Inn Sydney in June 2006.

Finance charges in 2007 were \$3 million higher than last year, primarily due to financings associated with the four hotels in western Canada acquired on November 1, 2006 and the Delta Regina acquired on August 1, 2007.

Corporate taxes in 2007 were \$2 million lower than last year. Corporate taxes during 2007 were reduced by a \$4 million favourable adjustment resulting from enacted future federal income tax rate reductions. Corporate taxes during 2006 were reduced by approximately \$2 million, also the result of future federal income tax rate reductions.

Outlook: Fortis Properties' Real Estate Division operates primarily in Atlantic Canada, with the majority of its properties located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates to reduce the risk of vacancy exposure. There is a continued focus in this Division on a strategy of early tenant renewals.

Fortis Properties' Hospitality Division currently operates in eight Canadian provinces. The hospitality industry is impacted by economic factors such as fluctuating energy costs and increasing municipal taxes. Increased supply of hotel rooms in many of the markets in which the Hospitality Division operates has created competitive challenges in recent years and will continue to do so in 2008. The Hospitality Division operates in the mid-to-upper market which targets a large customer base, allowing the Company to reduce exposure to risk associated with a specific market segment.

Corporate and Other ⁽¹⁾

Financial Highlights

Years Ended December 31st

(\$ millions)

	2007	2006	Variance
Total Revenue	22	9	13
Operating Expenses	13	11	2
Amortization	6	3	3
Finance Charges ⁽²⁾	70	41	29
Foreign Exchange Gain	–	(2)	2
Corporate Tax Recovery	(12)	(11)	(1)
Preference Share Dividends	6	2	4
Net Corporate and Other Expenses	(61)	(35)	(26)

⁽¹⁾ Includes non-regulated Terasen corporate-related activities and financial results of CWLP from May 17, 2007, the date of acquisition

⁽²⁾ Includes dividends on preference shares classified as long-term liabilities



The Corporate and Other segment captures expense and revenue items not specifically related to any other reportable segment. Included in this segment are finance charges including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; foreign exchange gains or losses; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes. Also included in the Corporate and Other segment are the financial results of CWLP. CWLP is a non-regulated shared-service business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting.

Net corporate and other expenses in 2007 were \$26 million higher than last year, driven by Terasen acquisition-related finance charges.

Revenue in 2007 was \$13 million higher than last year. The increase was primarily due to the inclusion of revenue from CWLP of \$8 million from the date of acquisition and higher inter-company interest revenue due to increased inter-company lending.

Operating expenses in 2007 were \$2 million higher than last year; however, operating expenses last year included \$1.7 million in business development costs. Excluding this item, operating expenses in 2007 were almost \$4 million higher than last year, driven largely by Terasen corporate and CWLP operating expenses.

The increase in finance charges year over year was driven by Terasen acquisition-related finance charges of approximately \$25 million from the date of acquisition; increased credit-facility borrowings in support of general corporate activities; and interest on US\$40 million of unsecured subordinated convertible debentures issued in November 2006 to fund, in part, the increased investment in Caribbean Utilities. The increase was partially offset by the impact of lower foreign exchange translation associated with US dollar-denominated interest payments.

An approximate \$2 million (\$1.7 million after-tax) foreign exchange translation gain on unhedged corporate US dollar-denominated debt was recorded in 2006. There was no similar foreign exchange translation gain during 2007, as all corporate US dollar-denominated debt has been designated as a hedge against the Corporation's US dollar-denominated foreign net investments. During 2007, all foreign exchange translation gains and losses on corporate US dollar-denominated debt in effective hedging relationships were recorded in other comprehensive income.

Corporate tax recovery in 2007 was \$1 million higher than last year, due to the impact of higher tax-deductible corporate expenses, partially offset by the impact of lower enacted future federal income tax rates on future income tax assets.

The increase in preference share dividends year over year was associated with the First Preference Shares, Series F issued on September 28, 2006.

In September 2007, Fortis privately placed US\$200 million 6.60% senior unsecured notes, due September 2037. The net proceeds were used to refinance existing credit-facility indebtedness associated with the Terasen acquisition and for general corporate purposes.

Management Discussion and Analysis

Regulatory Highlights

The nature of regulation and summary of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%)			Supportive Features
			2006	2007	2008	Future or Historical Test Year Used to Set Rates
			ROE			COS ⁽¹⁾ /ROE
TGI	BCUC	35	8.80	8.37	8.62	PBR mechanism through 2009: TGI: 50/50 sharing of earnings above or below the allowed ROE.
TGVI	BCUC	40	9.50	9.07	9.32	TGVI: 100 per cent retention of earnings from lower-than-forecasted operating and maintenance costs but no relief from increased operating and maintenance costs. ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
FortisBC	BCUC	40	9.20	8.77	9.02	COS/ROE PBR mechanism through 2008, with option to continue in 2009 – 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
FortisAlberta	Alberta Energy and Utilities Board ("AEUB") (to December 31, 2007) Alberta Utilities Commission ("AUC") (effective January 1, 2008)	37	8.93	8.51	8.75	COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	9.24 +/- 50 bps	8.60 +/- 50 bps	8.95 +/- 50 bps	COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields
						Future Test Year
Maritime Electric	IRAC	40	10.25	10.25	10.00	COS/ROE Future Test Year
FortisOntario	OEB (Canadian Niagara Power) Franchise Agreement (Cornwall Electric)	50	9.00	9.00	9.00	Canadian Niagara Power – COS/ROE Cornwall Electric – Price cap with commodity cost flow through Historical Test Year
						Four-year COS/ROA agreements with market-based returns
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00 – 15.00	10.00 – 15.00	10.00 – 15.00	Future Test Year
Caribbean Utilities	Electricity Regulatory Authority (effective 2008 under proposed new licences)	N/A	15.00	15.00	10.00 ⁽²⁾	COS/ROA Price-cap adjustment mechanism tied to consumer price indices (effective 2008 under proposed new 20-year licences) Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50	17.50	17.50	COS/ROA Future Test Year

⁽¹⁾ Cost of service

⁽²⁾ As per proposed new licences

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI and TGI	- March 2007, BCUC approval of extension of PBR mechanisms through 2009 for both TGI and TGI. - November 2007, TGI received conditional BCUC approval for the construction of a 1.5 billion-cubic foot liquefied natural gas ("LNG") storage facility on Vancouver Island for a total estimated cost of between \$175 million and \$200 million. - BCUC approval of various rates at TGI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2008. Increased mid-stream costs are flowed through to customers without markup. The approved rates also reflect the impact of an increase in the allowed ROE for 2008 to 8.62 per cent.
FortisBC	- December 2006, BCUC approval of a 1.2 per cent increase in customer rates, effective January 1, 2007. - March 2007, BCUC order changing the treatment of financing costs associated with large capital projects during the period of construction. Result was an additional 2.1 per cent increase in 2007 customer rates, effective April 1, 2007. The impact of the increase in electricity rates relating to the period January 1, 2007 through March 31, 2007 will be recovered in 2008 customer rates. The amount to be recovered was accrued in the first quarter of 2007. - Preliminary 2008 Revenue Requirements Application filed on October 1, 2007 and updated by FortisBC on November 1, 2007. - December 2007, BCUC approval of an NSA associated with 2008 revenue requirements resulting in a rate increase of 2.9 per cent, effective January 1, 2008. The rate increase was primarily the result of the Company's extensive capital investment program and higher power purchase costs due to ongoing customer growth and increased electricity demand. Rates for 2008 reflect an allowed ROE of 9.02 per cent. - BCUC-approved NSA included updated 2007 gross capital expenditures of approximately \$147 million for 2007 and \$132 million for 2008. - FortisBC intends on filing a 2009 and 2010 Capital Plan and a 2009 Revenue Requirements Application with the BCUC in the second half of 2008.
FortisAlberta	- June 2006, AEUB-approved 2006/2007 NSA associated with 2006/2007 revenue requirements, providing for a 0.7 per cent distribution rate increase, effective January 1, 2007. - AEUB initially approved 2007 distribution revenue requirements based on an allowed ROE of 8.93 per cent. The ROE was reduced to 8.51 per cent, effective January 1, 2007, due to the impact of lower long-term Canada bond yields on the automatic adjustment formula used to calculate the allowed ROE. As a result of the lower allowed ROE, FortisAlberta will refund to customers in 2008 rates approximately \$1 million of revenue collected in base rates in 2007. - June 2007, AEUB approval to sell amounts in annual AESO Charges Deferral Account. In September 2007, approximately \$28 million of the 2006 AESO Charges Deferral Account was sold to a Canadian chartered bank for cash consideration of approximately \$27 million and a receivable of approximately \$1 million, due February 15, 2009. In December 2007, approximately \$37 million of the 2007 AESO Charges Deferral Account was sold to a Canadian chartered bank for cash consideration of approximately \$36 million and a receivable of approximately \$1 million, due February 15, 2010. - June 2007, filing of 2008/2009 revenue requirements requesting an increase in base distribution rates of 8.5 per cent, effective January 1, 2008, and 9.0 per cent, effective January 1, 2009. - November 2007, filing of an NSA associated with 2008/2009 revenue requirements. - December 2007, regulatory approval of interim distribution rates, effective January 1, 2008. - February 2008, regulatory approval of NSA associated with 2008/2009 revenue requirements resulting in distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009. The approved NSA includes forecast gross capital expenditures of approximately \$264 million for 2008 and \$296 million for 2009, primarily to meet customer growth and improve system reliability. The 2008 revenue requirements included in the 2008/2009 NSA were determined using the 2007 ROE of 8.51 per cent. The impact of the increase in the ROE for 2008 to 8.75 per cent is subject to deferral-account treatment and, as such, will be recognized as earned and is expected to be collected in future customer rates. - Effective January 1, 2008, FortisAlberta is regulated by the AUC due to the separation of the AEUB into two separate regulatory bodies.
Newfoundland Power	- December 2006, PUB approval, on an interim basis, of an average 0.07 per cent increase in customer electricity rates, effective January 1, 2007. The increase was due to a change in the flow through of costs from Newfoundland Hydro, driven by increased purchased power costs and the resulting change in the wholesale purchased power rate, partially offset by the impact of a reduction in Newfoundland Power's allowed ROE to 8.60 per cent, effective January 1, 2007. There was no impact on Newfoundland Power's earnings in 2007 due to the change in the flow through of costs from Newfoundland Hydro. In April 2007, the PUB ordered the final approval of the average 0.07 per cent increase in customer electricity rates, effective January 1, 2007. - December 2006, PUB approval of an application requesting amortization of \$2.7 million of unrecognized 2005 unbilled revenue as revenue in 2007 to offset the 2007 income tax impact of changing to the accrual method for revenue recognition, the deferred recovery of capital asset amortization of \$5.8 million similar to 2006 and the deferred recovery of \$1.8 million associated with the cost of replacement energy required to be purchased while the Company's Rattling Brook hydroelectric generating facility is being refurbished.

Management Discussion and Analysis

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Newfoundland Power (cont'd)	- September 2007, PUB approval of 2008 Capital Budget totalling approximately \$51 million. - December 2007, PUB approval of NSA associated with 2008 General Rate Application resulting in an average 2.8 per cent increase in customer rates, effective January 1, 2008. The rate increase is largely driven by higher amortization costs. The rate increase reflects an allowed ROE of 8.95 per cent for 2008. - PUB approval of the NSA will also result in, among other things: (i) the amortization of \$7.2 million in 2008 and \$4.6 million in each of 2009 and 2010 of the remaining \$16.4 million balance of the original December 2005 unbilled revenue liability; (ii) amortization of approximately \$3.9 million in each of 2008, 2009 and 2010 of previously deferred amortization expense; (iii) amortization over a period of three to five years of certain deferred regulatory balances; (iv) for 2008 through 2010, the deferral of variations in purchased power expense caused by differences in the actual unit cost of energy and the unit cost reflected in customer rates to be recovered from, or refunded to, customers through operation of the Company's rate stabilization account.
Maritime Electric	- October 2007, IRAC approval of 2008 gross capital expenditures of approximately \$19 million. - October 2007, filing for customer rates for the period April 1, 2008 through March 31, 2009, requesting an increase in basic electricity rates of 1.8 per cent. - January 2008, IRAC approval, as filed, of a 1.8 per cent increase in basic electricity rates, effective April 1, 2008, and approval of a maximum allowed ROE of 10.00 per cent for 2008.
FortisOntario	- April 2007, OEB approval of an average 0.9 per cent increase in electricity distribution rates, effective May 1, 2007, for operations in each of Fort Erie, Port Colborne and Gananoque. Increase determined using OEB's incentive rate mechanism, comprised of a 1.9 per cent increase for inflation, partially offset by a 1 per cent decrease for a productivity adjustment. - July 2007, OEB approval for the recovery in customer rates, as requested, of approximately \$2 million in extraordinary costs incurred as a result of the snowstorm in October 2006. The extraordinary costs, which had been previously deferred, are being recovered mostly over a period of two years, beginning September 2007.
Belize Electricity	- June 2007, PUC Final Decision on tariffs for the period July 1, 2007 to June 30, 2008 approving changes to tariffs for certain customer classes while maintaining the average electricity rate at BZ44.1 cents per kWh. - Final Decision reflected many recommendations provided by an independent expert who was appointed by the PUC, subsequent to the objection by Belize Electricity and the Government of Belize of the PUC's Initial Decision on the Tariff Application. - Belize Electricity objected to and appealed the Final Decision associated with adjustments for cost of power, commercial loss targets and penalties associated with reliability targets. - In December 2007, amendments to the <i>Electricity (Tariffs, Charges and Quality of Services Standards) By-Laws</i> (Belize) affecting the tariff-setting process at Belize Electricity were enacted. The result is a simplified tariff-setting methodology allowing for improved rate stabilization. The amendments settled outstanding matters related to the PUC's June 2007 Final Decision on tariffs, effective July 1, 2007. - The overall average electricity rate of BZ44.1 cents per kWh remains in effect for the period July 1, 2007 to June 30, 2008. The recovery of the cost of power component of rates remained at BZ25.3 cents per kWh, while the value-added component of rates increased BZ0.6 cents per kWh to BZ16.8 cents per kWh and the component of rates associated with the recovery of rate stabilization accounts decreased BZ0.6 cents per kWh to BZ2.0 cents per kWh.
Caribbean Utilities	- Under its existing licence, Caribbean Utilities was entitled to a 4.5 per cent rate increase, effective August 1, 2007, primarily due to the cost associated with the write-down of the steam-turbine assets, increased operating costs and investment in capital assets. - Basic rate increase not implemented August 1, 2007, due to freezing of basic electricity rates during the period that the Hurricane Ivan cost-recovery surcharge ("CRS") is effective. - An AIP was reached with the Government of the Cayman Islands in December 2007 on the terms of a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year T&D licence. The terms of the AIP include competition for future generating capacity and the general promotion of renewable resources. The new licences are expected to be issued in the first half of 2008. - Effective January 1, 2008, as a result of the AIP, basic customer rates were reduced by 3.25 per cent, the CRS was removed and a fuel-duty rebate funded by the Government of the Cayman Islands was implemented for residential customers consuming less than 1,500 kWh monthly, resulting in average monthly savings to residential customers of approximately 15 per cent. The 3.25 per cent reduction in basic rates will reduce annual revenue by approximately US\$2 million. Additionally, Caribbean Utilities has forgone US\$2.6 million of revenue in 2008 as a result of the early elimination of the CRS. Following the initial basic rate reduction, customer rates will be frozen until May 31, 2009 and will be subject to annual review thereafter. - The AIP will see the replacement of the current allowed ROA of 15 per cent with a rate cap and adjustment mechanism based on published consumer price indices. Customer rates will now be set using an initial targeted ROA of 10 per cent beginning in 2008.

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets of Fortis between December 31, 2007 and December 31, 2006. The significant changes in the consolidated balance sheets associated with the consolidation of Terasen as at December 31, 2007 are itemized separately below.

Significant Changes in the Consolidated Balance Sheets between December 31, 2007 and December 31, 2006

(\$ millions)	Increase due to Terasen	Other Increase/ (Decrease)	Explanation
Cash	18	(1)	The other decrease in cash was not significant.
Accounts receivable	349	–	Included in the change associated with Terasen was a \$129 million increase in accounts receivable from the date of acquisition as a result of a seasonal increase in sales.
Regulatory assets – current and long-term	146	(5)	The other decrease in regulatory assets was driven by the sale of the majority of FortisAlberta's 2006 AESO Charges Deferral Account, partially offset by an increase in energy costs deferred at Maritime Electric, due to higher energy prices, and the deferral of other post-employment benefit ("OPEB") costs at Newfoundland Power in excess of that expensed under the cash method of accounting. Included in the change associated with Terasen was a \$50 million increase in regulatory assets from the date of acquisition, driven by an increase in the fair market value of the gas commodity swap contracts that is deferred in a rate stabilization account.
Inventories of gas, materials and supplies	203	(3)	The other decrease in materials and supplies was not significant. Included in the change associated with Terasen was a \$108 million increase in inventories of gas, materials and supplies from the date of acquisition, as a result of the typical seasonal injection of gas into storage.
Deferred charges and other assets	27	(22)	The other decrease in deferred charges and other assets was driven by the reclassification of \$21 million of deferred financing costs and \$11 million of unamortized deferred losses associated with a previously cancelled forward interest rate swap contract to long-term debt and accumulated other comprehensive loss, respectively, upon adoption of new accounting standards for Financial Instruments, Hedges and Comprehensive Income on January 1, 2007. The decrease was partially offset by an increase in accrued pension assets.
Future income tax assets – long-term	18	12	The other increase in future income tax assets primarily related to the tax impact of costs associated with the issuance of Common Shares upon the conversion of Subscription Receipts on May 17, 2007.
Utility capital assets	2,841	306	The other increase in utility capital assets primarily related to \$670 million invested in electricity systems, partially offset by customer contributions, amortization for the 12-month period and the impact of foreign exchange on the translation of US dollar-denominated utility capital assets. Included in the change associated with Terasen was a \$73 million net increase in utility capital assets from the date of acquisition, due to capital spending, less amortization for the period.
Income producing properties	–	50	The increase in income producing properties primarily related to the acquisition of the Delta Regina by Fortis Properties on August 1, 2007.
Intangibles, net of amortization	9	(4)	The other decrease in intangibles was not significant. The change in intangibles associated with Terasen primarily related to the fair value of customer contracts at CWLP recorded on acquisition as part of the purchase price allocation, less amortization for the period.
Goodwill	907	(24)	The other decrease in goodwill primarily related to the impact of foreign exchange on the translation of US dollar-denominated goodwill amounts.
Short-term borrowings	376	1	The other increase in short-term borrowings was not significant. Included in the change associated with Terasen was a \$100 million increase in short-term borrowings from the date of acquisition, largely driven by seasonality of operations including the impact of increased gas inventories.

Management Discussion and Analysis

Significant Changes in the Consolidated Balance Sheets between December 31, 2007 and December 31, 2006 (cont'd)

(\$ millions)	Increase due to Terasen	Other Increase/ (Decrease)	Explanation
Accounts payable and accrued charges	409	51	The other increase in accounts payable and accrued charges primarily related to an increase in the amounts owing by FortisAlberta to the AESO for transmission costs and flow through of customer receipts, in addition to the impact of increased capital spending. Included in the change associated with Terasen was a \$120 million increase in accounts payable and accrued charges from the date of acquisition, driven by an increase in the fair market value of the gas commodity swap contracts and the timing of payments.
Dividends payable	–	21	The increase in dividends payable was driven by increased Common Shares outstanding associated with the issuance of 5.17 million Common Shares in January 2007 and the issuance of 44.3 million Common Shares in May 2007, upon the completion of the acquisition of Terasen. The increase was also due to a 4-cent increase in the declared quarterly dividend.
Income taxes payable	27	3	The other increase in income taxes payable was not significant. Income taxes payable at Terasen decreased \$37 million from \$64 million as at the date of acquisition.
Deferred credits	170	12	The other increase in deferred credits was primarily due to an increase in the OPEB liability at Newfoundland Power.
Regulatory liabilities – current and long-term	32	1	The other increase in regulatory liabilities was not significant.
Long-term debt and capital lease obligations (including current portion)	2,077	339	The other increase in long-term debt and capital lease obligations was driven by the issuance of long-term debt and increased net committed credit-facility borrowings. The increase was partially offset by the impact of the early repayment of a US\$28.5 million term loan at BECOL; the conversion of US\$9 million of the Corporation's 6.75% and 5.5% unsecured subordinated convertible debentures; regular debt repayments; the reclassification of \$21 million in deferred financing costs, net of amortization during the period, from deferred charges and other assets, upon adoption of new accounting standards for Financial Instruments, Hedges and Comprehensive Income on January 1, 2007; and the impact of foreign exchange upon the translation of US dollar-denominated debt. The issuance of long-term debt, primarily to repay committed credit-facility borrowings and finance capital expenditures, was comprised of a \$110 million senior unsecured debenture offering by FortisAlberta, a \$70 million first mortgage sinking fund bond issue by Newfoundland Power, a \$105 million senior unsecured debenture offering by FortisBC, and a US\$40 million unsecured note issue by Caribbean Utilities. In addition, US\$200 million senior unsecured notes were issued by the Corporation, primarily to refinance existing indebtedness associated with the Terasen acquisition and for general corporate purposes. TGI also issued \$250 million in unsecured debentures to repay \$250 million in long-term debt that matured in October 2007. The net \$25 million increase in committed credit-facility borrowings was driven by net drawings of \$124 million by the Corporation, partially offset by net reductions of \$76 million by FortisAlberta, \$2 million by Newfoundland Power and \$21 million by FortisBC.
Non-controlling interest	–	(15)	The decrease in non-controlling interest primarily related to the impact of foreign exchange on the translation of US dollar-denominated non-controlling interest amounts.
Shareholders' equity	–	1,325	The increase in shareholders' equity primarily related to the \$1.12 billion, net of after-tax expenses, issuance of Common Shares, upon the conversion of Subscription Receipts, to substantially finance the net cash purchase price of Terasen; the \$146 million, net of after-tax expenses, issuance of Common Shares in January 2007, combined with net earnings reported for the year, less common share dividends. The increase was partially offset by an increase in accumulated other comprehensive loss driven by the impact of foreign exchange on the translation of the Corporation's net investments in foreign subsidiaries, and a \$5 million transitional adjustment to opening accumulated other comprehensive loss upon adoption of new accounting standards for Financial Instruments, Hedges and Comprehensive Income on January 1, 2007.

Liquidity

The following table outlines the summary of cash flows.

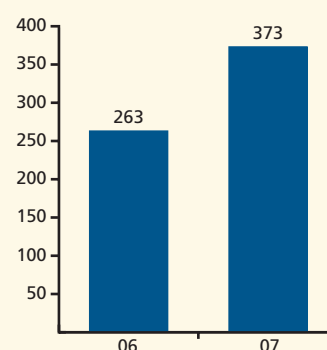
Years Ended December 31st

(\$ millions)

	2007	2006	Variance
Cash, beginning of year	41	33	8
Cash provided by (used in)			
Operating activities	373	263	110
Investing activities	(2,033)	(634)	(1,399)
Financing activities	1,680	379	1,301
Foreign currency impact on cash balances	(3)	–	(3)
Cash, end of year	58	41	17

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2007 was \$110 million higher than last year. The increase was driven by FortisAlberta, Caribbean Utilities and FortisBC, partially offset by cash used in operating activities at the Terasen Gas companies. The increase in cash from operating activities at FortisAlberta was driven by the sale of amounts in the Company's AESO Charges Deferral Account; the impact of corporate tax refunds received during 2007 compared to corporate taxes paid during 2006; the positive impact of changes in other regulatory deferral accounts; and the timing of accounts receivable and accounts payable. The increase at FortisBC was driven by the timing of accounts receivable and accounts payable. Cash used in operating activities at the Terasen Gas companies was driven by the build-up of gas inventories and accounts receivable from customers from the date of acquisition, due to seasonality of the business, combined with the timing of payment of corporate income taxes. The increase in cash flow from operating activities associated with Caribbean Utilities was the result of the Corporation consolidating the financial results of Caribbean Utilities on a two-month lag basis beginning with the first quarter of 2007, due to increasing its investment to an approximate 54 per cent controlling interest in November 2006. During 2006, Caribbean Utilities was accounted for on an equity basis on a two-month lag.

Cash Flow from Operating Activities
(\$ millions)



Investing Activities: Cash used in investing activities in 2007 was approximately \$1.4 billion higher than last year, primarily due to the acquisition of Terasen on May 17, 2007 for \$3.7 billion, including assumed debt of approximately \$2.4 billion. This acquisition resulted in a cash payment, including acquisition costs, of approximately \$1.25 billion, net of cash acquired. On August 1, 2007, Fortis Properties acquired the Delta Regina for a net cash purchase price of approximately \$50 million. Business acquisition activity during 2006 included the acquisition of Fortis Turks and Caicos in August 2006 for a net cash purchase price of approximately \$76 million; the acquisition of an additional approximate 16 per cent ownership interest in Caribbean Utilities for a net cash purchase price of approximately \$53 million; and the acquisition by Fortis Properties of four hotels in Alberta and British Columbia for a net cash purchase price of approximately \$40 million. Cash used in investing activities also increased year over year due to significantly higher utility capital expenditures.

Gross utility capital expenditures in 2007 were \$790 million, \$307 million higher than last year. The increase was primarily due to capital expenditures incurred at the Terasen Gas companies, Fortis Turks and Caicos and Caribbean Utilities; increased capital spending at FortisAlberta and FortisBC; and the commencement of the construction of the 18-MW hydroelectric generating facility at Vaca on the Macal River in Belize during the second quarter of 2007. Gross utility capital expenditures also increased due to the refurbishment of the Rattling Brook hydroelectric generating facility at Newfoundland Power during 2007.

Contributions received in aid of construction in 2007 were \$19 million higher than last year, primarily related to the Terasen Gas companies, as well as increased utility capital expenditures at FortisAlberta and FortisBC.

Management Discussion and Analysis

Financing Activities: Cash provided from financing activities in 2007 was \$1.68 billion, approximately \$1.3 billion higher than last year.

Proceeds from net short-term borrowings of \$103 million during 2007 were driven by net drawings by Terasen, Maritime Electric, Fortis Inc., Fortis Turks and Caicos, and Caribbean Utilities of \$100 million, \$11 million, \$6 million, \$5 million and \$5 million, respectively, partially offset by the repayment of \$22 million of net short-term borrowings by FortisBC with partial proceeds from its \$105 million debenture issue in July 2007.

Proceeds from long-term debt, net of issue costs, for 2007 compared to 2006 are summarized as follows:

Years Ended December 31st

(\$ millions)

	2007	2006	Variance
Borrowings under committed credit facilities:			
FortisAlberta	105	136	(31)
FortisBC	19	21	(2)
Newfoundland Power	62	19	43
Corporate	417	136	281
	603	312	291
Long-term debt issuances, net of costs:			
TGI	250 ⁽¹⁾	—	250
FortisAlberta	110 ⁽²⁾	100 ⁽³⁾	10
FortisBC	104 ⁽⁴⁾	—	104
Newfoundland Power	70 ⁽⁵⁾	—	70
Caribbean Utilities	48 ^{(6) (7)}	—	48
Corporate	209 ⁽⁸⁾	45 ⁽⁹⁾	164
Other	6	12	(6)
	797	157	640
Total	1,400	469	931

⁽¹⁾ Issued October 2007, 6.00% Unsecured Medium-Term Note Debentures, due October 2037

⁽²⁾ Issued January 2007, 4.99% Senior Unsecured Debentures, due January 2047

⁽³⁾ Issued April 2006, 5.40% Senior Unsecured Debentures, due April 2036

⁽⁴⁾ Issued July 2007, 5.90% Senior Unsecured Debentures, due July 2047

⁽⁵⁾ Issued August 2007, 5.901% First Mortgage Sinking Fund Bonds, due August 2037

⁽⁶⁾ Issued November 2007, US\$10 million 5.65% Senior Unsecured Notes, due June 2022

⁽⁷⁾ Issued June 2007, US\$30 million 5.65% Senior Unsecured Notes, due June 2022

⁽⁸⁾ Issued September 2007, US\$200 million 6.60% Senior Unsecured Notes, due September 2037

⁽⁹⁾ Issued November 2006, US\$40 million 5.50% Unsecured Subordinated Convertible Debentures, due November 2016

Borrowings under committed credit facilities by FortisAlberta, FortisBC and Newfoundland Power during 2007 and 2006 were primarily in support of their respective capital expenditure programs.

Borrowings by the Corporation under its committed credit facility in 2007 were used primarily to fund, on an interim basis, the remaining cash purchase price of Terasen, including certain acquisition costs; to fund Common Share issuance costs; to repay certain debt assumed upon the acquisition of Terasen; to finance a significant portion of the cash purchase price of the Delta Regina in August 2007; and in support of general corporate activities. Borrowings by the Corporation under its committed credit facilities in 2006 were used primarily to finance, in part, the acquisition by Fortis Properties of four hotels in Alberta and British Columbia in November 2006; to finance, in part, the acquisition of the additional 16 per cent ownership interest in Caribbean Utilities in November 2006; to fund the August 2006 acquisition of Fortis Turks and Caicos; to fund an equity requirement of one of the Corporation's western electric utilities; and for general corporate activities.

Net proceeds from the Corporation's US\$200 million unsecured notes issued in September 2007 were used to repay existing indebtedness previously borrowed under the Corporation's committed credit facility associated with the Terasen acquisition and for general corporate purposes. Net proceeds from the Corporation's US\$40 million unsecured convertible debentures in 2006 were

used to fund, in part, the acquisition of the additional approximate 16 per cent ownership interest in Caribbean Utilities. Most of the net proceeds from long-term debt issuances at FortisAlberta, FortisBC and Newfoundland Power during 2007 and 2006 were used to repay indebtedness previously borrowed under respective committed credit facilities and for general corporate purposes. Net proceeds from Caribbean Utilities' US\$40 million unsecured notes in 2007 were used to repay debt and to finance capital expenditures. The proceeds from the issuance of \$250 million unsecured debentures at TGI in October 2007 were used to refinance \$250 million of existing debt that matured in October 2007.

Repayments of long-term debt and capital lease obligations for 2007 compared to 2006 are summarized as follows:

Years Ended December 31st

(\$ millions)

	2007	2006	Variance
Repayment of committed credit-facility borrowings:			
FortisAlberta	181	97	84
FortisBC	40	–	40
Newfoundland Power	64	–	64
Corporate	293	72	221
	578	169	409
Repayment of long-term debt and capital lease obligations:			
TGI	250	–	250
Newfoundland Power	36	–	36
BECOL	28	–	28
Other	49	28	21
	363	28	335
Total	941	197	744

The repayment of committed credit-facility borrowings by FortisAlberta, FortisBC and Newfoundland Power during 2007 and 2006 was financed with partial proceeds from various long-term debt issuances, in addition to proceeds from the sale of FortisAlberta's 2006 AESO Charges Deferral Account. During 2007, the net repayment of committed credit-facility borrowings by the Corporation was financed with partial proceeds from a 5.17 million Common Share issue in January 2007 and the US\$200 million unsecured notes issued in September 2007. During 2006, the net repayment of committed credit-facility borrowings by the Corporation was financed with partial proceeds from a \$125 million (\$121 million net of costs) preference share offering in September 2006. The repayment of maturing long-term debt by TGI in October 2007 was financed with proceeds from the issuance of the \$250 million 6.00% unsecured debentures. The repayment of maturing long-term debt by Newfoundland Power in 2007 was financed with partial proceeds from the Company's \$70 million 5.901% first mortgage sinking fund bonds issued in August 2007. In November 2007, the term loan at BECOL was repaid in full.

Net proceeds associated with the issuance of Common Shares under the Corporation's share purchase and stock option plans in 2007 were \$23 million compared to \$15 million last year. Additionally, on May 17, 2007, the Corporation publicly issued 44.3 million Common Shares for gross proceeds of approximately \$1.15 billion (\$1.1 billion net of costs) upon conversion of Subscription Receipts that were initially issued in March 2007, to finance a significant portion of the net cash purchase price of Terasen. In January 2007, 5.17 million Common Shares were publicly issued for gross proceeds of approximately \$150 million (\$143 million net of costs). A significant portion of the net proceeds from the Common Share issue in January 2007 was used to repay approximately \$84 million of existing indebtedness incurred under the Corporation's committed credit facilities. The remainder of the net proceeds was utilized to fund equity requirements of the Corporation's regulated electric utilities in western Canada, in support of their respective capital expenditure programs, and for general corporate purposes.

Common share dividends were \$128 million for 2007, up \$55 million from last year. The increase was due to an increase in the number of Common Shares outstanding, primarily due to the issuance of Common Shares pursuant to the Terasen acquisition and the issuance of 5.17 million Common Shares in January 2007, and a higher dividend per common share compared to 2006.

The \$4 million increase in preference share dividends year over year related to the preference shares that were issued in September 2006.

Management Discussion and Analysis

Contractual Obligations: Consolidated contractual obligations over the next five years and for periods thereafter, as at December 31, 2007, are outlined in the following table.

(\$ millions)	Total	≤ 1 year	>1–3 years	4–5 years	> 5 years
Long-term debt ⁽¹⁾	5,057	433	412	623	3,589
Brilliant Terminal Station ("BTS") ⁽²⁾	66	3	5	5	53
Gas purchase contract obligations ⁽³⁾	537	515	22	–	–
Power purchase obligations					
FortisBC ⁽⁴⁾	2,856	40	74	76	2,666
FortisOntario ⁽⁵⁾	286	21	43	45	177
Maritime Electric ⁽⁶⁾	7	7	–	–	–
Belize Electricity ⁽⁷⁾	15	2	2	2	9
Capital cost ⁽⁸⁾	402	14	34	39	315
Joint-use asset and shared service agreements ⁽⁹⁾	66	4	8	6	48
Office lease – FortisBC ⁽¹⁰⁾	20	1	2	2	15
Operating lease obligations ⁽¹¹⁾	176	20	33	30	93
Other	25	6	10	9	–
Total	9,513	1,066	645	837	6,965

⁽¹⁾ In prior years, TGV received non-interest bearing repayable loans from the federal and provincial governments of \$50 million and \$25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGV to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGV's approved capital structure, as will TGV's rate base, which is used in determining customer rates. The repayment criteria were met in 2007 and TGV is expected to make an approximate \$6 million repayment on the loans in 2008. As at December 31, 2007, the outstanding balance of the repayable government loans was \$67 million with approximately \$6 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGV's revenue deficiency deferral account and the ability of TGV to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

⁽²⁾ On July 15, 2003, FortisBC began operating the BTS under an agreement, the term of which expires in 2056 (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination). The BTS is jointly owned by CPC/CBT and is used by the Company on its own behalf and on behalf of CPC/CBT. The agreement provides that FortisBC will pay CPC/CBT a charge related to the recovery of the capital cost of the BTS and related operating costs.

⁽³⁾ Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2007.

⁽⁴⁾ Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the Power Purchase Agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The Power Purchase Agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW, but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

- ⁽⁵⁾ Power purchase obligations for FortisOntario primarily include a long-term take-or-pay contract between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The contract, which expires on December 31, 2019, provides approximately one-third of Cornwall Electric's load. Cornwall Electric also has a two-year contract in place with Hydro-Québec Energy Marketing which expires on June 30, 2008. This take-or-pay contract provides energy on an as-needed basis but charges for 100 MW of capacity at \$0.14 million per month.
- ⁽⁶⁾ Maritime Electric has one take-or-pay contract with New Brunswick Power ("NB Power") for the purchase of either capacity or energy. This contract totals approximately \$7 million through March 31, 2008.
- ⁽⁷⁾ Power purchase obligations for Belize Electricity include a 15-year power purchase agreement between Belize Electricity and Hydro Maya Limited, which commenced in February 2007, for the supply of 3 MW of capacity and a two-year power purchase agreement between Belize Electricity and Comisión Federal de Electricidad of Mexico, expiring in August 2008, for the supply of 15 MW of firm energy. Belize Electricity has also signed a 15-year power purchase agreement with Belize Cogeneration Energy Limited ("Belcogen"), which is scheduled to commence in mid-2009, that provides for the supply of approximately 14 MW of capacity. Belcogen has not yet commenced construction of the related bagasse-fired electric generating facility; therefore, the obligation related to the power purchase agreement with Belcogen has not been included in the Corporation's contractual obligations.
- ⁽⁸⁾ Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.
- ⁽⁹⁾ FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2012 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.
- ⁽¹⁰⁾ Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.
- ⁽¹¹⁾ Operating lease obligations include certain office, warehouse, natural gas T&D asset, vehicle and equipment leases and the lease of electricity distribution assets of Port Colborne Hydro Inc.

Capital Resources

The Corporation's principal business of regulated gas and electric distribution utilities requires ongoing access to capital to allow it to fund the maintenance and expansion of infrastructure. To help ensure access to capital, the Corporation targets a long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt and investment-grade credit ratings. The capital structure of Fortis is presented in the following table.

	December 31, 2007		December 31, 2006	
	(\$ millions)	(%)	(\$ millions)	(%)
Total debt and capital lease obligations (net of cash) ⁽¹⁾	5,476	64.3	2,700	61.1
Preference shares ⁽²⁾	442	5.2	442	10.0
Common shareholders' equity	2,601	30.5	1,276	28.9
Total	8,519	100.0	4,418	100.0

⁽¹⁾ Includes long-term debt, including current portion, and short-term borrowings, net of cash

⁽²⁾ Includes preference shares classified as both long-term liabilities and equity

Management Discussion and Analysis

The change in the capital structure in 2007 was driven by the issuance of 5.17 million Common Shares in January 2007, for net after-tax proceeds of approximately \$146 million; the issuance of 44.3 million Common Shares in May 2007, for net after-tax proceeds of \$1.12 billion; the \$2.4 billion of consolidated debt assumed upon the acquisition of Terasen; additional debt incurred to partially finance the net cash purchase price of Terasen; and debt incurred at the subsidiaries in support of their capital expenditure programs. The capital structure was also impacted by net earnings applicable to common shares, less common share dividends, of \$65 million during 2007 and an increase in accumulated other comprehensive loss of \$37 million during 2007.

Effective June 19, 2007, S&P raised the long-term corporate credit rating of Fortis to 'A-' from 'BBB+' and the unsecured debt credit rating of Fortis to 'A-' from 'BBB'. The credit rating upgrades reflect the improved diversity of Fortis resulting from the acquisition of Terasen; the stand-alone operations and the financial separation of each of the regulated subsidiaries of Fortis; management's commitment to maintaining low levels of debt at the holding company level; the continued focus of Fortis on pursuing acquisitions of stable regulated utilities; and the success of FortisAlberta and FortisBC in executing their large capital expenditure programs.

The Corporation's credit ratings are as follows:

S&P	A- (long-term corporate and unsecured debt credit rating)
DBRS	BBB(high) (unsecured debt credit rating)

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. During 2007, approximately \$87 million in maintenance and repairs was expensed compared to approximately \$59 million during 2006. The increase year over year was driven by the inclusion of the Terasen Gas companies in the Corporation's financial results from May 17, 2007, the date of acquisition; the impact of the consolidation of Caribbean Utilities' financial results during 2007; and the first full year of ownership of Fortis Turks and Caicos.

During 2007, actual gross consolidated utility capital expenditures of Fortis were \$790 million, which exceeded the estimate of \$610 million, as disclosed at December 31, 2006, by \$180 million. The increase was driven by the Terasen Gas companies and FortisAlberta. The Terasen Gas companies spent approximately \$120 million from the date of acquisition. The increase in capital spending at FortisAlberta was driven by load growth and inflation and was included in FortisAlberta's 2008/2009 revenue requirements application.

A summary of gross utility capital expenditures for 2007 by segment and asset category is provided in the following table.

Gross Utility Capital Expenditures

Year Ended December 31, 2007

(\$ millions)	Terasen Gas Companies ⁽¹⁾	Fortis Alberta ⁽¹⁾⁽²⁾	Fortis BC ⁽¹⁾	Newfoundland Power ⁽¹⁾	Other Regulated Utilities – Canadian ⁽¹⁾	Total Regulated Utilities – Canadian	Regulated Utilities – Caribbean	Non-Regulated	Total ⁽³⁾
Generation	–	–	21	20	3	44	33	17	94
Transmission	50	–	67	5	5	127	9	–	136
Distribution	62	202	38	39	27	368	43	1	412
Facilities, equipment, vehicles and other	5	63	14	4	2	88	19	4	111
Information technology	3	20	7	4	1	35	2	–	37
Total	120	285	147	72	38	662	106	22	790

⁽¹⁾ Gross utility capital expenditures include removal and site restoration expenditures which are permissible in rate base.

⁽²⁾ Excludes payments of \$2 million made to the AESO for investment in transmission facilities

⁽³⁾ Includes expenditures associated with assets under construction

Gross consolidated utility capital expenditures for 2008 are expected to be approximately \$890 million. Planned capital expenditures are based on detailed forecasts of customer demand, weather, and cost of labour and materials, as well as other factors which could change and cause actual expenditures to differ from forecasts.

A summary of forecast gross utility capital expenditures for 2008 by segment and asset category is provided in the following table.

Forecast Gross Utility Capital Expenditures

Year Ending December 31, 2008

(\$ millions)	Terasen Gas Companies ⁽¹⁾	Fortis Alberta ⁽²⁾	Fortis BC ⁽¹⁾	Newfoundland Power ⁽¹⁾	Other Regulated Utilities – Canadian ⁽¹⁾	Total Regulated Utilities – Canadian	Regulated Utilities – Caribbean	Non- Regulated	Total⁽³⁾
Generation	–	–	17	4	3	24	25	32	81
Transmission	107	–	75	6	6	194	13	–	207
Distribution	125	196	31	36	24	412	55	1	468
Facilities, equipment, vehicles and other	5	51	8	3	2	69	7	15	91
Information technology	13	17	5	4	3	42	1	–	43
Total	250	264	136	53	38	741	101	48	890

⁽¹⁾ Gross utility capital expenditures include removal and site restoration expenditures which are permissible in rate base.

⁽²⁾ Excludes forecast payments of \$22 million to be made to the AESO for investment in transmission facilities

⁽³⁾ Includes expenditures associated with assets under construction

The percentage breakdown of 2007-actual and 2008-forecast gross utility capital expenditures among growth, sustaining and other is as follows:

Year Ended December 31st

(%)	Actual 2007	Forecast 2008
Growth	46	50
Sustaining ⁽¹⁾	35	35
Other ⁽²⁾	19	15
Total	100	100

⁽¹⁾ Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

⁽²⁾ Related to facilities, equipment, vehicles, information technology systems and other assets

Management Discussion and Analysis

Significant utility capital expenditure projects are summarized in the table below.

(\$ millions)		Actual 2007	Forecast 2008	Costs to complete after 2008	Expected year to complete
Utility	Nature of project				
Terasen Gas Companies	LNG storage facility – Vancouver Island	–	50	125–150	2011
	Squamish-to-Whistler pipeline	16 ⁽¹⁾	11	1	2008/2009
	Texada Island Compressor Station	10 ⁽¹⁾	–	–	2007
	Replacement of the Vancouver low-pressure system	5 ⁽¹⁾	6	–	2008
FortisAlberta	New operations facility in Airdrie	21	8	–	2008
	Automated Meter Infrastructure (“AMI”) technology	7	24	80	2010
FortisBC	New/upgraded substations and associated transmission lines	49	13	–	2008
	Generation asset Upgrade and Life-Extension Program	20	16	46	2011
Newfoundland Power	Rattling Brook hydroelectric generating plant refurbishment	17	–	–	2007
Caribbean Utilities	New 16-MW diesel-fired generating unit	20	–	–	2007
Non-Regulated – Fortis Generation	18-MW Vaca hydroelectric generating facility in Belize	14	30	13	2009

⁽¹⁾ Capital expenditures are from May 17, 2007, the date of acquisition

During 2008, TGI is expected to spend \$50 million on the construction of a new 1.5 billion-cubic foot LNG storage facility on Vancouver Island to meet current and future gas demands. The facility is expected to be completed by 2011 for a total cost of approximately \$175 million to \$200 million. It will allow more efficient use of TGI's existing pipeline systems and result in improved reliability and security of supply during planned or unplanned system interruptions or in times of high demand. In November 2007, TGI received conditional BCUC approval for the construction of the facility. Construction is expected to begin in April 2008 with the facility coming into service by late 2011. During 2007, approximately \$16 million was spent on the extension of TGI's pipeline system to Whistler through the construction of a 50-kilometre pipeline lateral from Squamish to Whistler. The extension is required in conjunction with the conversion of TGI's piped propane system to natural gas. The total capital cost of the project is estimated at approximately \$40 million, including amounts incurred prior to 2007 and amounts recorded in regulatory deferral accounts associated with the pipeline conversion.

Approximately 405,000 customer sites at FortisAlberta will have their conventional meters replaced by new AMI technology. AMI technology will allow for remote collection of meter data and result in more accurate reporting of customer consumption to retailers, based on actual rather than estimated usage. This technology change will improve billing accuracy, increase customer satisfaction, reduce customer inquiries and significantly reduce the operating cost of the current manual meter-reading practice. In 2008, FortisAlberta is expected to spend \$24 million on AMI technology, which is expected to be fully implemented by 2010 at an estimated capital cost of approximately \$111 million over the four-year period.

During 2007, work commenced at FortisBC on a number of new substations, substation upgrades and associated transmission lines. Total capital expenditures associated with these projects was \$49 million in 2007, with \$13 million expected to be incurred in 2008.

Since 1998, FortisBC's hydroelectric generating facilities have been subject to an Upgrade and Life-Extension Program which is forecast to conclude in 2011. Approximately \$20 million was spent on this Program in 2007, with an additional \$62 million expected to be incurred from 2008 through 2011.

In May 2007, BECOL received all major approvals for the construction of an estimated \$57 million (US\$53 million) 18-MW hydroelectric generating facility at Vaca on the Macal River in Belize. In 2008, BECOL is expected to spend \$30 million (US\$28 million) on the construction of this generating facility. Belize Electricity has signed a 50-year power purchase agreement with BECOL for the purchase of energy to be generated by the Vaca facility, which is expected to commence operations late in 2009. The facility is being constructed downstream from the Chalillo and Mollejon hydroelectric generating facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. Assuming normal hydrology, the facility is expected to be immediately accretive to earnings per common share of Fortis when it comes into service late in 2009.

During 2007, capital expenditures associated with income producing properties totalled approximately \$13 million. In addition, Fortis Properties purchased the Delta Regina for approximately \$50 million. Fortis Properties expects to spend approximately \$11 million in capital projects in 2008.

Fortis expects gross electric utility capital expenditures of more than \$3 billion over the next five years will be driven by FortisAlberta, FortisBC, and the Corporation's regulated and non-regulated electric utility operations in the Caribbean. Fortis expects gross gas utility capital expenditures over the next five years to exceed \$1 billion.

The cash required to complete the planned capital programs is expected to be derived from a combination of long-term and short-term borrowings, internally generated funds and the issuance of common shares and preference shares. Fortis does not anticipate any difficulties accessing the required capital on reasonable market terms.

Cash Flows: The Corporation's ability to service debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions which may limit their ability to distribute cash to Fortis.

As at December 31, 2007, the Corporation and its subsidiaries had consolidated authorized lines of credit of \$2.2 billion, of which \$1.1 billion was unused. The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

(\$ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	Total as at December 31, 2007	Total as at December 31, 2006
Total credit facilities	715	1,506	13	2,234	952
Credit facilities utilized					
Short-term borrowings	(6)	(468)	(1)	(475)	(98)
Long-term debt	(208)	(322)	—	(530)	(235)
Letters of credit outstanding	(55)	(103)	(1)	(159)	(72)
Credit facilities available	446	613	11	1,070	547

At December 31, 2007 and December 31, 2006, certain borrowings under the Corporation's and subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Significant changes in total credit facilities from December 31, 2006 to December 31, 2007 are described as follows.

Corporate and Other

At December 31, 2007, Terasen Inc. had a \$100 million unsecured committed revolving credit facility, maturing in May 2009. This credit facility was reduced from \$180 million in July 2007 and is available for general corporate purposes. Letters of credit outstanding of \$55 million at Terasen Inc., related to its previously owned petroleum transportation business, are secured by a letter of credit from the former parent company.

On May 14, 2007, Fortis cancelled its \$50 million unsecured revolving committed credit facility and renegotiated and amended its \$250 million unsecured committed credit facility, extending the maturity date to May 2012 and increasing the amount available to \$500 million with the ability, at the Corporation's option, to increase the credit facility to an aggregate of \$600 million. During the fourth quarter of 2007, the Corporation increased the amount of its credit facility to \$600 million in accordance with the terms thereof.

Regulated Utilities

At December 31, 2007, TGI had a \$500 million unsecured committed revolving credit facility. In August 2007, the facility was renegotiated and extended with similar terms and matures in August 2012. At December 31, 2007, TGVI had a \$350 million unsecured committed revolving credit facility, maturing in January 2011. These facilities are utilized to finance working capital requirements and capital expenditures, and for general corporate purposes. TGVI also had a \$20 million subordinated unsecured committed non-revolving credit facility, maturing in January 2013. This facility can only be utilized for refinancing any annual repayments on non-interest bearing government loans.

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In May 2007, FortisAlberta terminated one of its \$10 million unsecured demand credit facilities and extended the maturity date of its \$200 million unsecured committed credit facility to May 2012 from May 2010.

In May 2007, FortisBC renegotiated and amended its \$150 million unsecured committed revolving credit facility, reallocating the amounts available between the 364-day portion of the facility and the three-year portion of the facility, and extending the maturity date of the three-year facility to May 2010 from May 2008. Additionally, the Company has the option to increase the credit facility to an aggregate of \$200 million, subject to bank approval.

On November 27, 2006, Caribbean Utilities renegotiated its credit facilities, increasing its capital expenditures line of credit from US\$13 million to US\$19 million, including amounts available for letters of credit, and increasing each of its US\$5 million operating line of credit and US\$5 million catastrophe standby loan to US\$7.5 million.

Off-Balance Sheet Arrangements

As at December 31, 2007, the Corporation had no off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

Business Risk Management

The following is a summary of the Corporation's significant business risks.

Regulation: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation which can impact future revenues and earnings. Management at each operating utility is responsible for working closely with regulators and local governments to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 90 per cent of the Corporation's operating revenue and equity income was derived from regulated utility operations in 2007 (2006 – 84 per cent), while approximately 81 per cent of the Corporation's operating earnings were derived from regulated utility operations in 2007 (2006 – 75 per cent). These regulated operations, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos, are subject to the normal uncertainties faced by regulated entities. These uncertainties include approvals by the respective regulatory authorities of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base. The ability of the utilities to recover the actual costs of providing services and to earn the approved rates of return depends on achieving the forecasts established in the rate-setting processes. Upgrades of existing gas and electricity systems and facilities and the addition of new infrastructure and facilities require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting rates, which include the impact of capital expenditures on rate base and/or cost of service. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities, and other matters which may, in turn, negatively affect the Corporation's results of operations or financial position.

Although Fortis considers the regulatory frameworks in each of the jurisdictions to be fair and balanced, uncertainties do exist at the present time. Regulatory frameworks in Alberta and Ontario have undergone significant changes since the deregulation of electricity generation and the introduction of retail competition. The regulations and market rules in these jurisdictions which govern the competitive wholesale and retail electricity markets are relatively new and there may be significant changes in these regulations and



market rules that could adversely affect the ability of FortisAlberta and FortisOntario to recover costs or to earn reasonable returns on capital. As these companies and their applicable regulators work through the regulatory processes, it is expected that there will be more certainty in evolving regulatory frameworks and environments.

Although all of the Corporation's regulated utilities currently operate under traditional cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as automatic rate of return formulas, are also being employed to varying degrees.

TGI, TGV and FortisBC are regulated by the BCUC and are subject to approved PBR mechanisms. The PBR mechanisms at TGI and TGV have been extended through 2009. The PBR mechanism at FortisBC runs through 2008, with an option to extend the term through 2009. The PBR mechanisms provide the utilities an opportunity to earn returns in excess of the allowed ROEs determined by the BCUC. Upon expiry of the PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or the particular terms of any such PBR mechanisms.

Integration of Terasen and Management of Expanding Operations: Fortis continues to integrate Terasen within the Fortis Group. As a result of the acquisition, significant demands may be placed on the managerial, operational and financial personnel and systems of the Corporation. No assurance can be given that the Corporation's systems, procedures and controls will be adequate to support the expansion of the Corporation's operations resulting from the acquisition. The Corporation's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

Operating and Maintenance Risks: Terasen is exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas, which could result in significant operational and environmental liability. The business of electricity distribution is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes. The facilities of the operating subsidiaries are also exposed to the effects of severe weather conditions and other acts of nature. In addition, many of these facilities are located in remote areas, which may make access difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from earthquakes, forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Corporation and its operating subsidiaries have insurance which provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part.

The Corporation's gas and electricity systems require maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the operating subsidiaries determine expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the capital expenditures which the operating subsidiaries believe are necessary to maintain, improve and replace their assets; the failure by the operating subsidiaries to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures despite maintenance programs could have a material adverse effect on the Corporation.

Natural Gas Prices: At times in the past, the price of natural gas has been only marginally lower than the comparable price for electricity for residential customers in British Columbia, especially on Vancouver Island. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing, the ability of the Terasen Gas companies to add new customers could be impaired, and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. The ability of the Terasen Gas companies to add new customers and sales volumes could also be affected by lower prices of other competitive energy sources, as some commercial and industrial customers have the ability to

Management Discussion and Analysis

switch to an alternative fuel. The Terasen Gas companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive with electricity rates. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. The operation of BCUC-approved rate stabilization accounts therefore serves to mitigate the effect on earnings of natural gas cost volatility. Future BCUC determinations could materially impact the ability of the Terasen Gas companies to recover the future cost of natural gas delivered to customers.

Natural Gas Supply: The Terasen Gas companies are dependent on a limited number of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the natural gas distribution customers of the Terasen Gas companies are located. As a result, regional market prices have been higher from time to time than prices elsewhere in North America as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia. In addition, the Terasen Gas companies are dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the Terasen Gas companies could experience outages, thereby affecting revenues and incurring costs to safely relight customers.

Economic Conditions: Typical of utilities, the general economic conditions of the Corporation's service territories influence energy sales. Gas and electricity sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. A general and extended decline in the economy in the Corporation's service territories would be expected to have the effect of reducing demand for gas and electricity over time. Such reduced demand could negatively impact revenue. However, the regulated nature of utility operations helps to reduce the impact that economic downturns may have on the Corporation's earnings. A prolonged downturn in the economy in the Corporation's service territories could adversely affect the business, results of operations and financial condition of the Corporation, despite the possibility of regulatory-approved means of compensating for reduced demand.

Fortis also holds investments in both commercial real estate and hotel properties. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations. The high quality of the real estate and hotel assets and commitment to productivity improvements reduce the exposure to industry fluctuations. Fortis Properties' real estate investments are anchored by high-quality tenants with long-term leases. Exposure to lease expiries averages approximately 10 per cent per annum over the next five years. Approximately 58 per cent of Fortis Properties' operating income was derived from hotel investments in 2007 (2006 – 52 per cent). Management believes that, based on the geographic diversity of its Hospitality Division with locations in Atlantic Canada, Ontario, Manitoba, Saskatchewan, Alberta and British Columbia, the Company is not exposed to a significant reduction in revenues. A 5 per cent decrease in revenues from the Hospitality Division would decrease basic earnings per common share of Fortis by approximately 1 cent.

Weather and Seasonality: The physical assets of the Corporation and its operating subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed by the operation of a weather normalization reserve, a regulatory mechanism approved by the PUB. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At TGI, a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by customers.

At the Terasen Gas companies, weather has a significant impact on distribution volume, as a major portion of the gas distributed by the Terasen Gas companies is ultimately used for space heating. Because of gas-consumption patterns, the Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Virtually all of the earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Despite preparation for severe weather, extraordinary conditions (such as Hurricane Ivan in September 2004) and other natural disasters will always remain a risk to utilities. Upon acquiring controlling interest in Caribbean Utilities and upon the acquisition of Fortis Turks and Caicos, the Corporation's exposure to risks from natural disasters in the Caribbean region increased. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and to reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. In Belize, the PUC provides for recovery of certain costs arising from hurricanes through a surcharge on electricity rates, thereby mitigating the financial impact to Belize Electricity.

Earnings from non-regulated generation assets are sensitive to rainfall levels but the geographic diversity of the Corporation's generation assets mitigates the risk associated with rainfall levels.

Interest Rates: Generally, allowed returns for regulated utilities in North America are exposed to changes in the general level of long-term interest rates. Earnings of such regulated utilities are exposed to changes in long-term interest rates associated with rate-setting mechanisms. The rate of return is either directly impacted through automatic adjustment mechanisms or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. Automatic adjustment mechanisms currently apply to the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power. Due to an increase in long-term Canada bond yields during 2007 and the operation of the automatic adjustment mechanisms, the allowed ROE at each of the above utilities has been reset. The 2007 allowed ROEs for the Corporation's four largest utilities, TGI, FortisAlberta, FortisBC and Newfoundland Power, were 8.37 per cent, 8.51 per cent, 8.77 per cent and 8.60 per cent, respectively. Effective January 1, 2008, the allowed ROEs for TGI, FortisAlberta, FortisBC and Newfoundland Power have increased to 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively. A significant decline in long-term interest rates could adversely affect the Corporation's ability to earn a reasonable ROE which, in turn, could have a material adverse effect on the Corporation's financial condition and results of operations.

The Corporation and its operating subsidiaries are also exposed to interest rate risk associated with short-term borrowings and floating rate debt. As described under the heading "Derivatives Instruments and Hedging", the Corporation and its operating subsidiaries may enter into interest rate swaps to help reduce this risk. Approximately 74 per cent of the Corporation's long-term debt facilities and capital lease obligations have maturities beyond five years. The following table outlines the nature of the Corporation's consolidated debt at December 31, 2007.

Total Debt

at December 31, 2007

	(\$ millions)	(%)
Short-term borrowings	475	8.6
Utilized variable-rate credit facilities classified as long-term	530	9.6
Variable-rate long-term debt and capital lease obligations (including current portion)	14	0.2
Fixed-rate long-term debt and capital lease obligations (including current portion)	4,515	81.6
Total	5,534	100

The Terasen Gas companies use a BCUC-approved interest rate deferral account to absorb interest rate fluctuations, thereby effectively fixing the rate of interest on short-term and variable-rate credit-facility borrowings.

Derivative Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates and natural gas prices through the use of derivative financial instruments. Derivative financial instruments, such as interest rate swap contracts and natural gas commodity swaps and options, are used only to manage risk and are not used for trading purposes. All derivative financial instruments must be measured at fair value, with changes in fair value being recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At rate-regulated utilities, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

The Corporation's earnings from its foreign investments are exposed to changes in the US dollar to Canadian dollar exchange rate. The Corporation has effectively decreased its exposure to foreign currency exchange rate fluctuations associated with earnings from its foreign net investments through the use of US dollar borrowings.

It is expected that a 4-cent change in the value of the US dollar would have an approximate 1-cent impact on basic earnings per common share of Fortis in 2008.

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Fortis has also designated its corporate-held US dollar-denominated long-term debt as a hedge of the foreign currency exchange risk related to its net investments in US dollar-denominated self-sustaining foreign operations. This hedge allows unrealized gains and losses on the translation of the US dollar-denominated long-term debt to be offset against unrealized foreign currency exchange gains and losses on the foreign net investments. The unrealized foreign currency exchange gains and losses on US dollar-denominated long-term debt and foreign net investments are recognized in other comprehensive income. As at December 31, 2007, approximately US\$50 million in foreign net investments remained available to be hedged.

Management will continue to hedge future exchange rate fluctuations related to its foreign net investments and US dollar earnings streams, where possible, through the use of future US dollar borrowings and will monitor the exposure of Fortis to foreign currency fluctuations on a regular basis.

Risks Related to TGV: TGV is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenues from the Government of British Columbia which currently cover approximately 20 per cent of the current cost of service. These revenues are due to expire at the end of 2011, after which time TGV's customers will be required to absorb the full commodity cost of gas and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining \$67 million non-interest bearing senior government debt, which is currently treated as a government contribution against rate base, will be required to be fully repaid. As this debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Capital Resources: The Corporation's financial position could be adversely affected if it or its operating subsidiaries fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due as well as anticipated capital expenditures. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. There can be no assurance that sufficient capital will be available on acceptable terms to fund such capital expenditures and to repay existing debt.

Generally, the Corporation and its regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the Corporation's finance charges.

Environment: The Corporation and its operating subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety. The costs arising from compliance with such laws, regulations and guidelines may be material to the Corporation. The process of obtaining environmental, health and safety regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. Environmental damage and other costs could potentially arise due to a variety of events, including severe weather, human error or misconduct, and equipment failure. However, there can be no assurance that such costs will be recoverable through customer rates at the regulated utilities and, if substantial, unrecovered costs may have a material adverse effect on the business, results of operations and financial condition of the Corporation.

Insurance: While the Corporation and its operating subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its operating subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authorities to recover the loss (or liability) through increased customer rates. However, there can be no assurance that regulatory authorities would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its operating subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's business, results of operations and financial condition.



It is anticipated that such insurance coverages will be maintained. However, there can be no assurance that the Corporation and its operating subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements.

Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government and government agencies. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Corporation.

Energy Prices and Cessation of the Niagara Exchange Agreement: The Corporation's primary exposure to changes in energy prices relates to its non-regulated energy sales in Ontario. Energy is sold to the Independent Electricity System Operator at market prices. The sensitivity of the Corporation's earnings to each \$1 per MWh change in the annual average wholesale market price of electricity in Ontario is expected to be approximately \$0.4 million. Non-regulated energy sales in Ontario largely relate to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine Generating Station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will not be renewed, effective May 1, 2009. During 2007, earnings' contribution associated with the Niagara Exchange Agreement was approximately \$15 million. This earnings' contribution will cease effective May 1, 2009. To a lesser degree, the Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

The regulated utilities of Fortis flow through gas, energy and fuel costs to customers in their respective gas and electricity rates.

Loss of Service Area: FortisAlberta serves a number of direct customers that reside within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently initiated pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could have a material adverse effect on the financial condition and results of operations of FortisAlberta.

First Nations Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations lands and maintain gas and electric distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Terasen Gas companies and FortisBC is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties such as the Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not adversely affect the business of the Terasen Gas companies and FortisBC. In addition, FortisAlberta has distribution assets on First Nations lands with access permits to these lands held by FortisAlberta's predecessor, TransAlta Utilities Corporation. In order for FortisAlberta to acquire these access permits, both the Department of Indian and Northern Affairs Canada and the individual Band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta Utilities Corporation and may be unable to negotiate land-usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material adverse effect on the business of FortisAlberta.

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Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments, including natural gas commodity swaps and options. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. Because the Terasen Gas companies deal with high credit-quality institutions, in accordance with established credit-approval practices, the Terasen Gas companies do not expect any counterparties to fail to meet their obligations. FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

Labour Relations: Approximately 59 per cent of the employees of the Corporation's operating subsidiaries are members of labour unions or associations which have entered into collective bargaining agreements with the operating subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or to renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material adverse effect on the results of operations, cash flow and earnings of the Corporation.

The organized employees of TGI are represented by the Canadian Office and Professional Employees Union, Local 378, which ratified a new five-year collective agreement with TGI expiring in March 2012, ending limited job action that began on September 23, 2007, and by the International Brotherhood of Electrical Workers ("IBEW"), Local 213, under a collective agreement expiring on March 31, 2011.

On December 31, 2007, the collective agreement between FortisAlberta and the United Utility Workers Association ("UUWA"), Local 200, was due to expire. On December 13, 2007, FortisAlberta reached a tentative three-year collective agreement with UUWA, Local 200, which was ratified by the membership in February 2008.

On November 30, 2007, the collective agreement between Fortis Properties and the Communications, Energy and Paperworkers Union, Local 651, representing employees at the Delta Regina, expired. Negotiations with the union commenced in January 2008.

On January 31, 2008, the collective agreement between FortisBC and IBEW, Local 213, was due to expire. FortisBC and IBEW, Local 213, reached a Memorandum of Agreement which was ratified in December 2007, extending the collective agreement for one year to January 31, 2009.

In September 2008, two collective agreements governing Newfoundland Power's unionized employees represented by IBEW, Local 1620, are due to expire. In December 2008, the collective agreement governing Maritime Electric's unionized employees represented by IBEW, Local 1432, is also due to expire.

Human Resources: The ability of Fortis to deliver superior operating performance in a cost-effective manner is dependent on the ability of its operating subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, Fortis utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives. In particular, Alberta has a highly competitive job market where the demand for certain job skills exceeds the supply, making it difficult to attract new employees.

Liquidity Risk: Earnings from Belize Electricity are denominated in Belizean dollars, earnings from Caribbean Utilities are denominated in Cayman Island dollars and earnings from FortisUS Energy, BECOL and Fortis Turks and Caicos are denominated in US dollars. As at December 31, 2007, the Cayman Island dollar and the Belizean dollar were pegged to the US dollar at C\$0.84 = US\$1.00 and BZ\$2.00 = US\$1.00, respectively. Foreign earnings derived in currencies other than the US dollar must be converted into US dollars before repatriation, presenting temporary liquidity risks. Due to the small size and cyclical nature of the economy in Belize, conversion of local currency into US dollars may be subject to restrictions from time to time.



Changes in Accounting Standards

The nature of and impact on Fortis of adopting the new Canadian Institute of Chartered Accountants ("CICA") accounting standards for Financial Instruments, Hedges and Comprehensive Income, effective January 1, 2007, is described in detail in Notes 2, 16 and 24 to the 2007 Fortis Inc. Annual Consolidated Financial Statements. The most significant impacts of adopting the new standards were: (i) the reallocation of \$21 million of deferred financing costs from deferred charges and other assets to long-term debt; (ii) the reporting of a Statement of Comprehensive Income; (iii) the recording, in other comprehensive loss, of unrecognized foreign currency translation gains and losses on US dollar-denominated debt that is hedging the Corporation's net investments in self-sustaining foreign operations; (iv) the reallocation of \$51 million of unrealized foreign currency translation losses on net investments in self-sustaining foreign operations from the foreign currency translation adjustment account in shareholders' equity to accumulated other comprehensive loss; (v) the reallocation of an \$11 million (\$7 million after-tax) unamortized loss balance relating to a previously cancelled interest rate swap agreement from deferred charges and other assets, and the reallocation of a \$3 million (\$2 million after-tax) unamortized gain balance relating to a previously cancelled US dollar forward currency swap agreement from deferred credits, to accumulated other comprehensive loss; and (vi) the recording of opening fair value and subsequent changes in fair value of the Corporation's interest rate swap contracts in effective hedging relationships in accumulated other comprehensive loss and other comprehensive loss, respectively. The adoption of the accounting standards did not have a material impact on the Corporation's 2007 consolidated statement of earnings.

Also as disclosed in Note 2 to the 2007 Fortis Inc. Annual Consolidated Financial Statements, Fortis adopted the revised standard for accounting changes, effective January 1, 2007. This new standard had no impact on the Corporation's consolidated financial statements for the year ended December 31, 2007, except for the disclosures provided in Note 3 to the 2007 Fortis Inc. Annual Consolidated Financial Statements.

Future Accounting Pronouncements

International Financial Reporting Standards ("IFRS"): In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five-year transitional period. In February 2008, the AcSB confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-oriented enterprises. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010. While Fortis has begun assessing the adoption of IFRS for 2011, the financial reporting impact on the Corporation of the transition to IFRS cannot be reasonably estimated at this time.

Rate-Regulated Operations: In March 2007, the AcSB issued an Exposure Draft on rate-regulated operations that proposed: (i) the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook, providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation be removed; (ii) the explicit guidance for rate-regulated operations provided in Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*, be removed; and (iii) Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation* ("AcG-19"), be retained as is.

In August 2007, the AcSB issued a Decision Summary on the Exposure Draft that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, and the amendment to Section 3465, *Income Taxes*, to recognize future income tax liabilities and assets as well as offsetting regulatory assets and liabilities at entities subject to rate regulation. Both changes will apply prospectively for fiscal years beginning on or after January 1, 2009. The AcSB also decided that the current guidance for rate-regulated operations pertaining to property, plant and equipment, disposal of long-lived assets and discontinued operations, and consolidated financial statements be maintained, and that the existing AcG-19 will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate-regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as "another source of GAAP" within the Canadian GAAP hierarchy.

Management Discussion and Analysis

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes*, will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the taxes-payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2007, would have been an increase in future tax assets and future tax liabilities of \$54 million and \$489 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of \$54 million and \$489 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates, and the separate disclosure of future income tax assets and liabilities that are currently not recognized. Fortis is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

Inventories: In March 2007, the AcSB approved the new Section 3031, *Inventories*, effective for fiscal years beginning on or after January 1, 2008. The new standard requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in, first-out inventory-costing methodology; and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This new standard is not expected to have a material impact on the Corporation's earnings, cash flow or financial position.

Capital Disclosures: As a result of new Section 1535, *Capital Disclosures*, Fortis will be required to include additional information in the Notes to the financial statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding an entity's objectives, policies and processes for managing capital. This Section is applicable to Fortis for the fiscal year beginning on January 1, 2008.

Disclosure and Presentation of Financial Instruments: New accounting recommendations for disclosure and presentation of financial instruments, Sections 3862 and 3863, are effective for the Corporation beginning on January 1, 2008. The new recommendations require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed.

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets of Fortis approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or nature of these instruments. The fair value of long-term debt is calculated by discounting the future cash flow of each debt instrument at the estimated yield to maturity for the same or similar issues at the balance sheet date, or by using available quoted market prices. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

The carrying and fair values of the Corporation's long-term debt and preference shares as at December 31st were as follows.

	2007 ⁽¹⁾		2006	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
(\$ millions)				
Long-term debt	5,023	5,635	2,614	2,940
Preference shares, classified as debt ⁽²⁾	320	346	320	355

⁽¹⁾ Includes long-term debt of Terasen from May 17, 2007, the date of acquisition

⁽²⁾ Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's \$122 million of preference shares classified as equity was \$107 million at December 31, 2007 (December 31, 2006 – \$129 million).

The Corporation hedges exposures to fluctuations in interest rates and natural gas commodity prices through the use of derivative financial instruments. The following table indicates the valuation of derivative financial instruments as at December 31st.

	2007 ⁽¹⁾				2006	
	Term to Maturity (years)	Number of Swaps	Carrying Value (\$ millions)	Estimated Fair Value (\$ millions)	Carrying Value (\$ millions)	Estimated Fair Value (\$ millions)
Liability						
Interest Rate Swaps	1 to 3	4	–	–	–	(1)
Natural Gas Commodity Swaps and Options	Up to 3	244	(79)	(79)	–	–

⁽¹⁾ Includes derivative financial instruments of the Terasen Gas companies from May 17, 2007, the date of acquisition

Two of the four interest rate swaps are held by Fortis Properties and are designated as hedges of the cash flow risk related to floating-rate long-term debt. The effective portion of changes in the value of the interest rate swaps at Fortis Properties is recorded in other comprehensive income. The remaining interest rate swaps and all of the natural gas commodity swaps and options are held by the Terasen Gas companies. The interest rate swaps are designated as hedges of cash flow risk related to floating-rate debt instruments. The natural gas commodity swaps and options are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts have floating, rather than fixed, prices. At the Terasen Gas companies, changes in the fair value of the interest rate swaps and the natural gas commodity swaps and options are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the swaps and options were recorded in accounts payable as at December 31, 2007.

The interest rate swaps are valued at the present value of future cash flows based on published forward future interest rate curves. The fair values of the natural gas commodity swaps and options reflect the estimated amount that the Corporation would have to pay if forced to settle all outstanding contracts at year end.

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate based on relevant market information about the instruments. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's regulated utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2007, Fortis recorded \$312 million in current and long-term regulatory assets (December 31, 2006 – \$171 million) and \$392 million in current and long-term regulatory liabilities (December 31, 2006 – \$359 million). The increase in regulatory assets year over year was

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largely associated with BCUC-approved rate stabilization accounts at the Terasen Gas companies. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2007 Fortis Inc. Annual Consolidated Financial Statements.

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2007, the Corporation's consolidated utility and income producing properties were \$7.2 billion, or approximately 70 per cent of total consolidated assets, compared to consolidated utility and income producing properties of \$4.0 billion, or approximately 74 per cent of total consolidated assets, as at December 31, 2006. The increase in capital assets was primarily associated with the Terasen Gas companies. Amortization expense for 2007 was \$273 million compared to \$178 million for 2006. Changes in amortization rates can have a significant impact on the Corporation's amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authorities. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount to provide for future removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual costs, net of salvage proceeds, are recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2007 was \$319 million (December 31, 2006 – \$307 million). The amount of future removal and site restoration costs provided for and reported in amortization expense during 2007 was \$33 million (2006 – \$30 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over or under amortization as a result of actual experience differing from that expected and provided for in previous amortization rates is generally reflected in future amortization rates and amortization expense, when the differences are refunded or collected in customer rates.

Capitalized Overhead: As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Belize Electricity capitalize overhead costs which are not directly attributable to specific capital assets, but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulators. In 2007, GEC totalled \$40 million (2006 – \$18 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a significant impact on the amount recorded as operating expenses and utility capital assets.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost, less any previous amortization and write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Corporation reviews for impairment of goodwill, which is based on current information and fair market value assessments of the reporting units being reviewed. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on \$1.54 billion in goodwill recorded on the Corporation's balance sheet as at December 31, 2007. The net increase in goodwill during 2007 was due to the acquisition of Terasen.

Employee Future Benefits: The Corporation's defined benefit pension plans and OPEB plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations were the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets. Other assumptions applied were average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates. Except for the assumptions of the expected long-term rate of return on plan assets and average rate of compensation increase, the above assumptions were also utilized by management in determining OPEB plan expense and obligations. Assumptions were also made regarding the health-care cost trend increase. FortisAlberta and Newfoundland Power record the cost of pension and/or OPEB plan expense on a cash basis. Therefore, changes in assumptions do not impact earnings

of those subsidiaries. As at December 31, 2007, the Corporation had a consolidated accrued benefit asset of \$120 million (December 31, 2006 – \$93 million) and a consolidated accrued benefit liability of \$150 million (December 31, 2006 – \$63 million). During 2007, the Corporation recorded consolidated net benefit expense of \$26 million (2006 – \$20 million).

The following table reflects the sensitivities associated with a 0.5 per cent increase and a 0.5 per cent decrease in the expected long-term rate of return on plan assets and discount rate on 2007 net benefit expense and the accrued benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the benefit obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2007

	Net benefit expense		Accrued benefit asset		Accrued benefit liability		Benefit obligation	
	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities
(\$ millions)								
Impact of increasing the rate of return assumption by 0.5 per cent	(1)	(2)	1	2	–	–	–	–
Impact of decreasing the rate of return assumption by 0.5 per cent	1	2	(1)	(2)	–	–	–	–
Impact of increasing the discount rate assumption by 0.5 per cent	(2)	(3)	–	2	(1)	(1)	(27)	(32)
Impact of decreasing the discount rate assumption by 0.5 per cent	3	3	(2)	(2)	1	1	23	35

Asset-Retirement Obligations ("AROs"): In measuring the fair value of AROs, the Corporation is required to make reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights of way at the end of the life of the systems and the remediation of certain leased land, there were no amounts recorded as at December 31, 2007 and 2006. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation facilities are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and to ensure the continued provision of service to customers; and the land-lease agreement at Maritime Electric is expected to be renewed indefinitely. In the event that environmental issues are identified, hydroelectric generating facilities are decommissioned or the applicable licences, permits, agreements or leases are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue Recognition: All of the Corporation's regulated utilities, except for Belize Electricity, recognize revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Prior to January 1, 2006, Newfoundland Power also recognized electricity revenue on a billed basis. Effective January 1, 2006, Newfoundland Power adopted, on a prospective basis, the accrual method for recognizing revenue as approved by the PUB. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that establish gas and electricity consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authorities. The development of the gas and electricity sales estimates requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2007, the amount of accrued unbilled

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revenue recorded in accounts receivable was approximately \$309 million (December 31, 2006 – \$132 million) on annual consolidated operating revenues of \$2.72 billion (2006 – \$1.46 billion).

Contingencies: Fortis is subject to various legal proceedings and claims that arise in the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately \$37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister has reduced the assessment to \$7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. On June 22, 2007, TGI filed an appeal of the assessment with the B.C. Supreme Court.

A non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

FortisAlberta

On March 24, 2006, Her Majesty the Queen in Right of Alberta (the "Crown") filed a statement of claim in the Court of Queen's Bench of Alberta in the Judicial District of Edmonton against FortisAlberta. The Crown's claim is that the Company is responsible for a fire that occurred in October 2003 in an area of the Province of Alberta commonly referred to as Poll Haven Community Pasture. The Crown is seeking approximately \$3 million in firefighting and suppression costs and approximately \$2 million in timber losses, as well as interest and other costs. FortisAlberta and the Crown have exchanged several investigation and expert reports. Both the factual evidence and expert opinion received to date lead management to believe that FortisAlberta is not responsible for the cause of the fire and has no liability for the damages. However, FortisAlberta has not made any definitive assessment of potential liability, and the outcome with regard to the Company's liability for the claims made by the Crown is indeterminable. No amount, therefore, has been accrued in the consolidated financial statements.

FortisBC

The B.C. Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a forest fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with two filed writs and statements of claim by private landowners in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the energy cost adjustment mechanism amounts in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately \$6 million on January 2, 2001 associated with a settlement with NB Power regarding the \$450 million write-down of the Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately \$13 million in taxes and accrued interest. As at December 31, 2007, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately \$6 million.

FortisUS Energy

Legal proceedings were initiated against FortisUS Energy by the Village of Philadelphia (the "Village"), New York. The Village claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately \$7 million (US\$7 million). The First American Title Insurance Company is defending the action on behalf of FortisUS Energy. A Memorandum Decision and Order was filed by the State of New York Supreme Court of Jefferson County on December 21, 2006 granting summary judgment to FortisUS Energy dismissing the action by the Village. An appeal of the summary judgment dismissal of the claim filed by the Village in January 2007 was heard by the Appellate Division, Fourth Judicial Department of the Supreme Court of the State of New York in December 2007. The Appellate Division delivered its Memorandum and Order on February 1, 2008 modifying the initial decision by dismissing the Village's appeal regarding its main claim, but reinstating a secondary cause of action dismissed by the summary judgment order. Further appeals to the New York State Court of Appeal may be forthcoming. Management believes that potential further legal actions by the Village will not be successful and, therefore, no provision has been made in the consolidated financial statements.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2007, 2006 and 2005. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

Years Ended December 31st

(\$ millions, except per share amounts)

	2007 ⁽¹⁾	2006	2005
Revenue and equity income	2,718	1,472	1,441
Net earnings	199	149	137
Net earnings applicable to common shares	193	147	137
Total assets	10,273	5,441	4,597
Long-term debt and capital lease obligations (net of current portion)	4,623	2,558	2,136
Preference shares ⁽²⁾	442	442	320
Common shareholders' equity	2,601	1,276	1,213
Basic earnings per common share	1.40	1.42	1.35
Diluted earnings per common share	1.32	1.37	1.24
Dividends declared per common share	0.88	0.70	0.61
Dividends declared per First Preference Share, Series C	1.3625	1.3625	1.3625
Dividends declared per First Preference Share, Series D	—	—	0.03 ⁽³⁾
Dividends declared per First Preference Share, Series E	1.2250	1.2250	1.2250
Dividends declared per First Preference Share, Series F ⁽⁴⁾	1.2250	0.5211	—

⁽¹⁾ Financial results for 2007 were significantly impacted by the acquisition of Terasen on May 17, 2007.

⁽²⁾ Includes preference shares classified as equity and as long-term debt

⁽³⁾ The First Preference Shares, Series D were redeemed in September 2005.

⁽⁴⁾ 5,000,000 First Preference Shares, Series F were issued on September 28, 2006 at \$25.00 per share for net after-tax proceeds of \$122 million and are entitled to receive cumulative dividends in the amount of \$1.2250 per share per annum.

Management Discussion and Analysis

2007/2006 – Revenue, including equity income, increased 84.6 per cent over 2006. The increase was driven by contributions from the Terasen Gas companies, from the date of acquisition, and the impact of consolidating the Corporation's approximate 54 per cent controlling ownership in Caribbean Utilities during 2007 compared to recording the Corporation's 37 per cent interest in Caribbean Utilities during 2006 on an equity basis. Net earnings applicable to common shares grew 31.3 per cent over 2006, attributable to the acquisition of Terasen in May 2007, the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes. The growth in total assets and increase in long-term debt in 2007 was driven by assets acquired and debt assumed upon the acquisition of Terasen in May 2007. The remaining increase in assets and long-term debt was primarily due to the Corporation's continued investment in electricity systems, driven by the capital expenditure programs at FortisAlberta and FortisBC and the acquisition of the Delta Regina, partially offset by the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. Common shareholders' equity more than doubled during 2007, driven by the issuance of approximately \$1.15 billion in common equity required to fund a significant portion of the net cash purchase price of Terasen. Basic earnings per common share decreased 1.4 per cent from 2006. The seasonality of earnings of the Terasen Gas companies combined with the impact of the \$1.15 billion common share issue diluted basic earnings per common share by 7 cents in 2007.

2006/2005 – Revenue, including equity income, increased 2.1 per cent over 2005. However, revenue at FortisAlberta in 2005 included approximately \$20 million largely related to the resolution of tax-related matters pertaining to prior years and the finalization of load settlement amounts and billing adjustments. The increase in revenue was largely driven by electricity sales growth at FortisAlberta and FortisBC, increased electricity rates at FortisBC and Belize Electricity and four months of revenue contribution from Fortis Turks and Caicos, partially offset by lower average wholesale energy prices in Ontario. Equity income from Caribbean Utilities was approximately \$2 million lower than in 2005, but equity income during 2005 included a \$1 million positive adjustment related to a change in Caribbean Utilities' accounting practice for recognizing unbilled revenue. Net earnings applicable to common shares in 2006 grew 7.3 per cent over 2005; however, earnings in 2005 included the \$8 million after-tax Ontario Settlement gain. Growth in earnings in 2006 was primarily driven by strong electricity sales growth at FortisAlberta and FortisBC; lower corporate income taxes at FortisAlberta; improved non-regulated hydroelectric generation in Belize; earnings growth at Fortis Properties; the overall 11 per cent increase in electricity rates at Belize Electricity, effective July 1, 2005; and four months of earnings' contribution from Fortis Turks and Caicos. The increase was partially offset by lower average wholesale energy prices in Ontario and higher corporate costs. The growth in total assets and increase in long-term debt in 2006 was primarily associated with the extensive capital expenditure programs at FortisAlberta and FortisBC; the acquisition of an additional approximate 16 per cent ownership interest in Caribbean Utilities; the assumption of long-term debt upon consolidating the Corporation's resulting controlling ownership interest in Caribbean Utilities; and the acquisition of Fortis Turks and Caicos and four hotels in western Canada and the assumption of related long-term debt. The Corporation also issued \$122 million in preference shares in 2006, the proceeds of which were primarily used to repay borrowings under the Corporation's committed credit facilities incurred, in part, to fund the acquisition of Fortis Turks and Caicos, and to fund equity injections into FortisAlberta and FortisBC in support of their extensive capital expenditure programs.

The Corporation's dividend payout ratio was 58.6 per cent in 2007 compared to 47.2 per cent in 2006. On June 1, 2007, Fortis increased its quarterly common share dividend paid to 21 cents from 19 cents. Commencing with the first quarter dividend paid on March 1, 2008, Fortis increased its quarterly common share dividend 19 per cent to 25 cents per common share from 21 cents.

Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2006 through December 31, 2007. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

(Unaudited)

Quarter Ended	Revenue and Equity Income (\$ millions)	Net Earnings Applicable to Common Shares (\$ millions)	Earnings per Common Share	
			Basic (\$)	Diluted (\$)
December 31, 2007	1,018	79	0.51	0.49
September 30, 2007	651	31	0.20	0.20
June 30, 2007	566	41	0.31	0.27
March 31, 2007	483	42	0.38	0.35
December 31, 2006	393	34	0.33	0.32
September 30, 2006	342	39	0.37	0.36
June 30, 2006	346	38	0.37	0.35
March 31, 2006	391	36	0.35	0.34

A summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Given the diversified group of companies, seasonality may vary. Financial results from May 17, 2007 were impacted by the acquisition of Terasen. Virtually all of the earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results from November 1, 2006 were impacted by the acquisition of four hotels in western Canada. Financial results from August 28, 2006 were impacted by the acquisition of Fortis Turks and Caicos, while earnings from January 1, 2007 were impacted by the consolidation of a controlling interest in Caribbean Utilities. The Corporation's interest in Caribbean Utilities was previously accounted for on an equity basis.

December 2007/December 2006 – Net earnings applicable to common shares were \$79 million, or \$0.51 per common share, for the fourth quarter of 2007, compared to earnings of \$34 million, or \$0.33 per common share, for the fourth quarter of 2006. The increase in earnings and earnings per common share was driven by contributions from the Terasen Gas companies, including a \$7 million after-tax gain on the sale of surplus land, partially offset by increased corporate costs driven by Terasen acquisition-related finance charges.

September 2007/September 2006 – Net earnings applicable to common shares were \$31 million, or \$0.20 per common share, for the third quarter of 2007, compared to earnings of \$39 million, or \$0.37 per common share, for the third quarter of 2006. A \$1.15 billion Common Share issue in May 2007 to fund a significant portion of the net cash purchase price of Terasen, combined with the seasonality of earnings of the Terasen Gas companies, diluted earnings per common share for the third quarter of 2007. Increased earnings' contribution from FortisAlberta, driven by customer growth and higher corporate income tax recoveries; increased earnings' contribution from Fortis Turks and Caicos, acquired in August 2006; and growth at Fortis Properties from expanded hospitality operations in western Canada were more than offset by higher finance charges associated with acquisitions, losses at the Terasen Gas companies due to seasonality of operations and lower non-regulated hydroelectric production due to lower rainfall.

Management Discussion and Analysis

June 2007/June 2006 – Net earnings applicable to common shares were \$41 million, or \$0.31 per common share, for the second quarter of 2007, compared to earnings of \$38 million, or \$0.37 per common share, for the second quarter of 2006. The \$1.15 billion Common Share issue, combined with the seasonality of earnings of the Terasen Gas companies, diluted earnings per common share for the second quarter of 2007. The increase in overall earnings was driven by customer growth and increased energy deliveries at FortisAlberta; rate increases and electricity sales growth at FortisBC; and earnings' contribution from Fortis Turks and Caicos, acquired in August 2006, and the Terasen Gas companies, acquired in May 2007. The increase was partially offset by higher acquisition-related finance charges, the impact of decreased non-regulated hydroelectric production and lower earnings at Fortis Properties. However, earnings at Fortis Properties during the second quarter of 2006 were favourably impacted by \$3 million associated with the sale of Days Inn Sydney and the reduction of future income tax liabilities.

March 2007/March 2006 – Net earnings applicable to common shares were \$42 million, or \$0.38 per common share, for the first quarter of 2007, up \$6 million from earnings of \$36 million, or \$0.35 per common share, for the first quarter of 2006. Excluding the Corporation's \$2 million share of a charge associated with the disposal of steam-turbine assets at Caribbean Utilities during the first quarter of 2007, earnings were \$8 million higher than for the first quarter of 2006. The increase was primarily due to electricity sales growth and lower corporate income taxes at FortisAlberta, increased non-regulated hydroelectric production in Belize, earnings' contribution from Fortis Turks and Caicos, and electricity sales growth and lower finance charges at Belize Electricity.

The impact of increased earnings on earnings per common share was partially offset by the dilution created by the approximate \$150 million issuance of 5.17 million Common Shares on January 18, 2007.

Management's Evaluation of Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure Controls and Procedures

The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintained disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO, together with management, have evaluated the effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2007 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting

The CEO and the CFO of Fortis, together with management, are also responsible for the design of internal controls over financial reporting within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design of the Corporation's internal controls over financial reporting as of December 31, 2007 and, based on that evaluation, have concluded that the design of the controls is effective to provide such reasonable assurance.

There has been no change in the Corporation's internal controls over financial reporting during the fourth quarter of 2007 that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

Subsequent Event

On February 15, 2008, TGV closed a \$250 million 6.05% unsecured debenture offering, maturing on February 15, 2038. The net proceeds of the debenture offering were used to repay existing credit-facility borrowings.



Outlook

The Corporation's principal business of regulated gas and electric distribution utilities is capital intensive. Over the next five years, the Corporation's consolidated utility capital program is expected to exceed \$4 billion. Most of its more than \$3 billion gross electric utility capital expenditures over the next five years will be driven by FortisAlberta, FortisBC and the Corporation's regulated and non-regulated electric utility operations in the Caribbean. Gross gas utility capital expenditures are expected to exceed \$1 billion. The Corporation's capital program should drive growth in earnings and dividends.

The Corporation continues to integrate Terasen within the Fortis Group. The addition of the gas distribution business doubled the Corporation's investment in regulated rate base assets to approximately \$6.3 billion. The Corporation is pursuing acquisitions for profitable growth, focusing on opportunities to acquire regulated natural gas and electric utilities in Canada, the United States and the Caribbean. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

Outstanding Share Data

At March 13, 2008, the Corporation had issued and outstanding 156,753,899 Common Shares; 5,000,000 First Preference Shares, Series C; 7,993,500 First Preference Shares, Series E and 5,000,000 First Preference Shares, Series F. As at December 31, 2007, the number of Common Shares that would be issued upon conversion of share options, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E is described in Notes 10, 13, 14 and 15 to the 2007 Fortis Inc. Annual Consolidated Financial Statements.

Additional information, including the Fortis 2007 Annual Information Form and Management Information Circular, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Management's Report

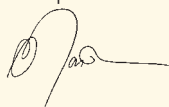
The accompanying Consolidated Financial Statements of Fortis Inc. and all information in the 2007 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including the amounts that must, of necessity, be based on estimates and informed judgments. These Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2007 Annual Report is consistent with that in the Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee.

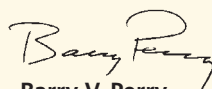
The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes. The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review shareholders' auditors' independence and auditors' fees.

The December 31, 2007 Consolidated Financial Statements and Management Discussion and Analysis contained in the 2007 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon recommendation of the Audit Committee, have performed an audit of the 2007 Consolidated Financial Statements and their report follows.



H. Stanley Marshall
President and Chief Executive Officer

St. John's, Canada



Barry V. Perry
Vice President, Finance and Chief Financial Officer

Auditors' Report

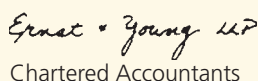
To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2007 and 2006 and the consolidated statements of earnings, retained earnings, comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

St. John's, Canada,
February 1, 2008



Chartered Accountants

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions)

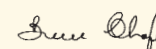
ASSETS	2007	2006
Current assets		
Cash and cash equivalents	\$ 58	\$ 41
Accounts receivable	635	286
Prepaid expenses	19	14
Regulatory assets (Note 4)	119	31
Inventories of gas, materials and supplies	233	33
	1,064	405
Deferred charges and other assets (Note 5)	179	174
Regulatory assets (Note 4)	193	140
Future income taxes (Note 19)	37	7
Utility capital assets (Note 6)	6,722	3,575
Income producing properties (Note 7)	519	469
Intangibles, net of amortization (Note 2)	15	10
Goodwill (Note 8)	1,544	661
	\$ 10,273	\$ 5,441
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 9)	\$ 475	\$ 98
Accounts payable and accrued charges	793	333
Dividends payable	43	22
Income taxes payable	30	–
Regulatory liabilities (Note 4)	20	19
Current installments of long-term debt and capital lease obligations (Note 10)	436	85
Future income taxes (Note 19)	7	1
	1,804	558
Deferred credits (Note 11)	261	79
Regulatory liabilities (Note 4)	372	340
Future income taxes (Note 19)	55	58
Long-term debt and capital lease obligations (Note 10)	4,623	2,558
Non-controlling interest (Note 12)	115	130
Preference shares (Note 13 (i) and (ii))	320	320
	7,550	4,043
Shareholders' equity		
Common shares (Note 14)	2,126	829
Preference shares (Note 13 (iii))	122	122
Contributed surplus	6	5
Equity portion of convertible debentures (Note 10)	6	7
Accumulated other comprehensive loss (Note 16)	(88)	(51)
Retained earnings	551	486
	2,723	1,398
	\$ 10,273	\$ 5,441

Commitments (Note 25)

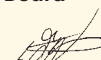
Contingent Liabilities (Note 26)

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board



Bruce Chafe,
Director



David G. Norris,
Director

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions, except per share amounts)

	2007	2006
Operating Revenues	\$ 2,718	\$ 1,462
Equity Income	–	10
	2,718	1,472
Expenses		
Energy supply costs	1,287	540
Operating	617	399
Amortization	273	178
	2,177	1,117
Operating Income	541	355
Finance charges (Note 17)	299	168
Gain on sale of property (Note 18)	(8)	(2)
	291	166
Earnings Before Corporate Taxes and Non-Controlling Interest	250	189
Corporate taxes (Note 19)	36	32
Net Earnings Before Non-Controlling Interest	214	157
Non-controlling interest	15	8
Net Earnings	199	149
Preference share dividends	6	2
Net Earnings Applicable to Common Shares	\$ 193	\$ 147
Earnings Per Common Share (Note 14)		
Basic	\$ 1.40	\$ 1.42
Diluted	\$ 1.32	\$ 1.37

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions)

	2007	2006
Balance at Beginning of Year	\$ 486	\$ 412
Net Earnings Applicable to Common Shares	193	147
	679	559
Dividends on Common Shares	(128)	(73)
Balance at End of Year	\$ 551	\$ 486

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions)

	2007	2006
Net Earnings	\$ 199	\$ 149
Unrealized foreign currency translation losses	(70)	(30)
Gains (losses) on hedges of net investments in self-sustaining foreign operations	48	(6)
Corporate (taxes) recovery	(9)	1
Change in Unrealized Foreign Currency Translation Losses, Net of Hedging Activities and Tax (Note 16)	(31)	(35)
Comprehensive Income	\$ 168	\$ 114

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions)

	2007	2006
Operating Activities		
Net earnings	\$ 199	\$ 149
Items not Affecting Cash		
Amortization – capital assets, net of contributions in aid of construction	261	168
Amortization – intangibles	5	4
Amortization – other	7	6
Future income taxes (Note 19)	–	10
Accrued employee future benefits	(2)	(3)
Non-controlling interest	15	8
Gain on sale of property (Note 18)	(8)	(2)
Other	2	(4)
Change in long-term regulatory assets and liabilities	11	(30)
Increase in corporate income tax deposit	–	(6)
	490	300
Change in non-cash operating working capital	(117)	(37)
	373	263
Investing Activities		
Change in deferred charges, other assets and deferred credits	(4)	(25)
Utility capital expenditures	(790)	(483)
Contributions in aid of construction	73	54
Income producing property capital expenditures	(13)	(17)
Proceeds on sale of capital assets	4	8
Business acquisitions, net of cash acquired (Note 21)	(1,303)	(169)
Increase in investments	–	(2)
	(2,033)	(634)
Financing Activities		
Change in short-term borrowings	103	38
Proceeds from long-term debt, net of issue costs	1,400	469
Repayments of long-term debt and capital lease obligations	(941)	(197)
Advances (to) from non-controlling interest	(3)	10
Issue of common shares, net of costs	1,267	15
Issue of preference shares, net of costs	–	121
Dividends		
Common shares	(128)	(73)
Preference shares	(6)	(2)
Subsidiary dividends paid to non-controlling interest	(12)	(2)
	1,680	379
Effect of exchange rate changes on cash and cash equivalents	(3)	–
Change in Cash and Cash Equivalents	17	8
Cash and Cash Equivalents, Beginning of Year	41	33
Cash and Cash Equivalents, End of Year	\$ 58	\$ 41

Supplementary Information to Consolidated Statements of Cash Flows (Note 23)

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's operating segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each operating segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGI") and Terasen Gas (Whistler) Inc. ("TGI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving approximately 825,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 91,200 residential, commercial and industrial customers.

In addition to providing transmission and distribution services to customers, TGI and TGI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGI owns and operates the propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 residential and commercial customers.

Regulated Electric Utilities – Canadian

- a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving over 448,000 customers.
- b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving approximately 154,000 customers. FortisBC Inc. owns four hydroelectric generating plants with a combined capacity of 223 megawatts ("MW"). During 2007, the entitlement capacity and energy output for a number of FortisBC Inc.'s hydroelectric generating units were optimized as a result of past turbine and generator upgrade projects. Entitlement capacity was rebalanced from 235 MW to 223 MW and energy output increased by 11,000 MW hours as a result of negotiated adjustments to the Canal Plant Agreement with BC Hydro.

Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 149-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna. FortisBC's assets also include the regulated electric utility formerly operated as Princeton Light and Power Company, Limited.

- c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 232,000 customers. Newfoundland Power has an installed generating capacity of 139 MW, of which 96 MW is hydroelectric generation.

- d. *Maritime Electric*: Maritime Electric is the principal distributor of electricity on Prince Edward Island, serving approximately 72,000 customers. Maritime Electric also maintains on-island generating facilities with a combined capacity of 150 MW.
- e. *FortisOntario*: FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario operations include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012. FortisOntario also owns a 10 per cent interest in each of Westario Power Holdings Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies formed in 2000, serving more than 27,000 customers.

Regulated Electric Utilities – Caribbean

- a. *Belize Electricity*: Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 73,000 customers. The Company has an installed generating capacity of 36 MW. Fortis holds a 70.1 per cent controlling interest in Belize Electricity.
- b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 23,000 customers. The Company has an installed generating capacity of 137 MW. On November 7, 2006, Fortis acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities and now owns approximately 54 per cent of the Company. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U) and has an April 30th fiscal year end. Caribbean Utilities' balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities' financial statements on a two-month lag basis and, accordingly, has consolidated Caribbean Utilities' October 31, 2007 balance sheet, and statements of earnings and cash flows for the 12-month period ended October 31, 2007 with the Corporation's December 31, 2007 Consolidated Financial Statements. During 2006, the statement of earnings of Fortis reflected the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities, accounted for on an equity basis, on a two-month lag.
- c. *P.P.C. Limited ("PPC") and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic") (collectively referred to as Fortis Turks and Caicos)*: Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands, serving more than 8,700 customers. The Company has a combined diesel-fired generating capacity of 48 MW. Fortis Turks and Caicos was acquired by Fortis, through a wholly owned subsidiary, on August 28, 2006.

Non-Regulated – Fortis Generation

- a. *Belize*: Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the electricity output is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. Hydroelectric generation operations in Belize are conducted through the Corporation's wholly owned indirect subsidiary, Belize Electric Company Limited ("BECOL"), under a Franchise Agreement with the Government of Belize.
- b. *Ontario*: Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement ("NEA"), a 5-MW gas-fired cogeneration plant in Cornwall and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. Non-regulated generation operations in Ontario are conducted through FortisOntario Inc. and Fortis Properties. On January 1, 2006, the former FortisOntario Generation Corporation was amalgamated with CNE Energy Inc. and, effective January 1, 2007, CNE Energy Inc. was amalgamated with Fortis Properties.
- c. *Central Newfoundland*: Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and Abitibi-Consolidated Corporation of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Since the amalgamation of CNE Energy Inc. with Fortis Properties on January 1, 2007, Fortis Properties has held directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement expiring in 2033.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

1. Description of the Business (cont'd)

Non-Regulated – Fortis Generation (cont'd)

- d. *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013. Hydroelectric generation operations in British Columbia are conducted through the Walden Power Partnership ("WPP"), a wholly owned partnership of FortisBC Inc.
- e. *Upper New York State*: Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the US Federal Energy Regulatory Commission. Hydroelectric generation operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary, FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 19 hotels with more than 3,500 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any other reportable segment. Included in this segment are finance charges including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; foreign exchange gains or losses; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes. Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. Terasen was acquired by Fortis on May 17, 2007.

2. Summary of Significant Accounting Policies

These Consolidated Financial Statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. These differences are described in Note 2, under the headings "Regulation", "Utility Capital Assets", "Employee Future Benefits", "Income Taxes" and "Revenue Recognition", and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

Terasen Gas Companies and FortisBC

The Terasen Gas companies and FortisBC are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. TGI, TGVI and FortisBC operate under both cost-of-service regulation and performance-based rate-setting ("PBR") methodologies as administered by the BCUC. The BCUC uses a future test year in the establishment of rates for the utilities and, pursuant to this method, forecasts the volume of gas that will be sold and transported for TGI and TGVI, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").



Under the PBR mechanism, TGI and customers equally share in achieved earnings above or below the allowed ROE. When TGI's earned ROE is greater than 200 basis points above the allowed ROE for two consecutive years, the PBR mechanism may be reviewed. Under the PBR mechanism, TGI is permitted to retain 100 per cent of earnings derived from lower-than-forecasted controllable operating and maintenance expenses; however, TGI is not provided any relief from increased controllable operating and maintenance expenses. The PBR agreements at TGI and TGI have been extended until 2009. During 2006, the BCUC approved a PBR agreement for FortisBC with a term from 2006 to 2008, with an option to extend the term to 2009. Under the PBR agreement, FortisBC and customers equally share achieved earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE. Any excess is subject to deferral treatment. FortisBC's portion of the PBR incentive is subject to the Company meeting certain performance standards and BCUC approval.

TGI's allowed ROE was 8.37 per cent for 2007 (2006 – 8.80 per cent) on a deemed capital structure of 35 per cent equity. TGI's allowed ROE was 9.07 per cent for 2007 (2006 – 9.50 per cent) on a deemed capital structure of 40 per cent equity. FortisBC's allowed ROE was 8.77 per cent for 2007 (2006 – 9.20 per cent) on a deemed capital structure of 40 per cent equity. The allowed ROE at each of TGI, TGI and FortisBC is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. TGI, TGI and FortisBC apply for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment and operation of the PBR mechanisms.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC"), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta) and the *Hydro and Electric Energy Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing. Prior to January 1, 2008, the Alberta Energy and Utilities Board ("AEUB") was the chief provincial regulator of the Alberta energy industry. Effective January 1, 2008, the *Alberta Utilities Commission Act* separated the AEUB into two separate regulatory bodies: the Energy Resource and Conservation Board and the AUC. Any use herein of the term "AUC" will refer to the AEUB prior to January 1, 2008 and the AUC subsequently.

FortisAlberta operates under cost-of-service regulation as prescribed by the AUC. The AUC uses a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.51 per cent for 2007 (2006 – 8.93 per cent) on a deemed capital structure of 37 per cent equity. FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields.

The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operation and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power. Newfoundland Power operates under cost-of-service regulation as administered by the PUB. The PUB uses a future test year in the establishment of rates for the utility and, pursuant to this method, the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which Newfoundland Power's customer rates are determined. In between test years, Newfoundland Power's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. Newfoundland Power's allowed ROE for 2007 was 8.60 per cent (2006 – 9.24 per cent) on a deemed capital structure of 45 per cent equity. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

2. Summary of Significant Accounting Policies (cont'd)

Regulation (cont'd)

Maritime Electric

Maritime Electric operates under a traditional cost-of-service regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island). The IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a deemed capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 10.25 per cent for 2007 (2006 – 10.25 per cent) on a deemed capital structure of 40 per cent equity. Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario) as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power operates under cost-of-service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. The electricity distribution rates are based upon costs associated with a historical test year, 2004, using a deemed capital structure of 50 per cent equity. FortisOntario's allowed ROE was 9.0 per cent for 2007 (2006 – 9.0 per cent).

Cornwall Electric is exempt from many aspects of the above Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, dated July 31, 1998. The rate-setting mechanism is subject to a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The primary duty of the PUC is to ensure that the services rendered by the Company are satisfactory and that the charges imposed in respect of those services are fair and reasonable. The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licences' conditions. Basic electricity rates for Belize Electricity are comprised of two components. The first component is value-added delivery ("VAD") and the second is the cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes and amortization, and allowed rate of return on rate base assets ("ROA") in the range of 10 per cent to 15 per cent. The VAD component of the tariff is normally reviewed every four years, while the COP component and any rate stabilization account ("RSA") recovery are reviewed at each annual rate proceeding and at Threshold Event Review Proceedings, which can occur when the deferrals of COP into the RSA exceed \$1.5 million (BZ\$3 million).

Effective for the full (four-year) tariff period beginning July 1, 2007, if the achieved ROA at the end of the full tariff period is below 10 per cent or above 15 per cent, rates are adjusted over the course of the next full tariff period.

Caribbean Utilities

Caribbean Utilities generates and distributes electricity in its exclusive licence area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands (the "Government"), originally dated May 10, 1966, amended November 1, 1979 and renewed for a further 25 years on January 17, 1986 (collectively, the "Licence"). The Licence allows for subscribers' tariffs to be adjusted annually to provide Caribbean Utilities with an allowed ROA of 15 per cent, as defined in the Licence.

An agreement in principle ("AIP") was reached with the Government in December 2007 on the terms of a new generation licence, initially to be granted for up to 25 years, and, under new arrangements, a new exclusive 20-year transmission and distribution licence for Caribbean Utilities. The new licences are expected to be issued in the first half of 2008, with impact on customer rates effective January 1, 2008. The AIP will see the replacement of the current allowed ROA of 15 per cent with a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer rates will now be set using an initial targeted ROA of 10 per cent. The AIP details the role of the Electric Regulatory Authority which will oversee all licences, establish and enforce licence standards, review the RCAM and annually approve capital expenditures.



Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through PPC and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated October 1987 and November 1986 (collectively, the "Agreements"), respectively. Among other matters, these Agreements describe how electricity rates are to be set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide Fortis Turks and Caicos with an ROA of 17.5 per cent (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

Fortis Turks and Caicos makes annual submissions to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfall. The submissions for 2007 calculated the Allowable Operating Profit for 2007 to be \$12 million (US\$12 million) and the cumulative shortfall at December 31, 2007 to be \$8 million (US\$8 million). Fortis Turks and Caicos has a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfalls. The recovery would, however, be dependent on future sales volumes and expenses.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of acquisition.

Inventories of Gas, Materials and Supplies

Inventories of gas in storage are valued at weighted-average cost. Materials and supplies are valued at the lower of average cost and market value, determined on the basis of estimated net realizable value.

Deferred Charges and Credits and Other Assets

Deferred charges and credits and other assets include deferred pension costs, accrued pension obligations, Alberta Electric System Operator ("AESO") contributions, deferred recoverable and project costs, deferred gains on sale of natural gas transmission and distribution assets, deferred payments, energy management loans, a corporate income tax deposit, an investment held at Fortis Properties as collateral for a loan, customer deposits, investments, long-term receivables, lease costs and other deferred charges and credits. AESO contributions represent payments to the AESO by FortisAlberta for investment in transmission facilities that are needed for reliability or contingency planning in accordance with AESO Terms and Conditions of Service. These assets are recovered in customer rates through AUC-approved amortization rates. Deferred recoverable costs are amortized over the estimated remaining useful lives of the projects. Project costs are deferred until a capital project has been identified, at which time the costs are transferred to utility capital assets or income producing properties. Energy management loans range in terms from one year to 10 years and are deferred until they are recovered from customers. The corporate income tax deposit relates to Maritime Electric's tax reassessment (Note 26). Other deferred charges and assets are recorded at cost and are amortized over the estimated period of future benefit.

As a result of adopting Section 3855, *Financial Instruments – Recognition and Measurement*, deferred financing costs of \$21 million, as at January 1, 2007, relating to long-term debt were reclassified from deferred charges and other assets to long-term debt on the balance sheet (Note 5).

As at January 1, 2007, in accordance with the transitional provisions of Section 3865, *Hedges*, unamortized deferred gain and loss balances related to previously cancelled swap agreements were reclassified to accumulated other comprehensive loss (Note 16). An unamortized loss balance of \$11 million (\$7 million after-tax), as at January 1, 2007, related to a previously cancelled interest rate swap agreement, was reclassified from deferred charges and other assets (Note 5), and an unamortized gain balance of \$3 million (\$2 million after-tax), as at January 1, 2007, related to a previously cancelled US dollar forward-currency swap agreement, was reclassified from deferred credits (Note 11).

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

2. Summary of Significant Accounting Policies (cont'd)

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966 with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values at November 30, 1984 with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values at September 18, 1986. Subsequent additions are at cost except for the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by agreements dated November 29, 1986 and October 8, 1987 for US\$2.00, in aggregate, as valued in the books of the companies. Utility capital assets of all other utility operations are stated at cost.

Contributions in aid of construction represent the cost of utility capital assets contributed by customers and governments. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense is recorded as a long-term regulatory liability. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. At December 31, 2007, the long-term regulatory liability for future removal and site restoration costs was \$319 million (December 31, 2006 – \$307 million) (Note 4 (xiv)). The Terasen Gas companies record actual removal and site restoration costs, net of salvage proceeds, against accumulated amortization. In the absence of a current depreciation study approved by its regulator, a reasonable estimate of any regulatory asset or liability associated with future removal and site restoration costs for the Terasen Gas companies cannot be made as at December 31, 2007. FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record removal and site restoration costs in earnings when incurred and these costs did not have a material impact on the Corporation's 2007 and 2006 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity, as required by their respective regulators, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer gas and electricity rates. At FortisOntario, Caribbean Utilities and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets, is recorded immediately in earnings.

In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity would be recognized in the current period. The loss charged to accumulated amortization in 2007 was approximately \$22 million (2006 – \$22 million).

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred while replacements and betterments are capitalized.

As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario and Belize Electricity capitalize overhead costs that are not directly attributable to specific utility capital assets, but which relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulators. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2007, GEC totalled \$40 million (2006 – \$18 million).

The Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity, as required by their respective regulators, include an equity component in the allowance for funds used during construction ("AFUDC") that is included in the cost of utility capital assets. Since AFUDC includes both an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges, and AFUDC capitalized during 2007 was \$8 million (2006 – \$4 million) (Note 17), including an equity component of \$3 million (2006 – \$2 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2007, amortization expense was reduced by \$5 million (2006 – \$5 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 0.4 per cent to 33.0 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2007 was 3.6 per cent (2006 – 4.2 per cent).

The service life ranges and average remaining service life of the Corporation's distribution, transmission and generation assets as at December 31st were as follows.

	2007		2006	
	Service Life Ranges (Years)	Average Remaining Service Life (Years)	Service Life Ranges (Years)	Average Remaining Service Life (Years)
Distribution				
Gas	10–100	33	–	–
Electric	10–75	28	10–75	27
Transmission				
Gas	10–50	38	–	–
Electric	10–75	34	10–75	30
Generation	5–75	32	5–75	31

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate, except where a write-down is required to reflect a permanent impairment. The lease terms vary to a maximum of 20 years. Equipment is recorded at cost and is amortized on a straight-line basis over a range of two years to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred while replacements and betterments are capitalized.

Intangibles

Intangibles include the estimated fair value of water rights associated with the Rankine Generating Station in Ontario and intangibles associated with the acquisition of Terasen. The water rights are being amortized using the straight-line method over the estimated life of the asset to April 30, 2009. Effective May 1, 2009, in accordance with the NEA, FortisOntario's water entitlement on the Niagara River associated with the Rankine Generating Station will not be renewed and earnings' contribution associated with the NEA will cease.

Upon the acquisition of Terasen, \$10 million was assigned as the value associated with customer contracts at CWLP. The intangible is being amortized using the straight-line method over the remaining term of the contracts to December 31, 2011. Approximately \$1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization. As at December 31, 2007, the net book value of intangibles was \$15 million (net of accumulated amortization of \$21 million) (2006 – \$10 million (net of accumulated amortization of \$15 million)).

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

2. Summary of Significant Accounting Policies (cont'd)

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives, deferred charges and other assets when events or changes in circumstances may indicate that the asset's carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques, is recognized in earnings in the period it is identified. There was no impact on the financial statements as a result of asset-impairments for the years ended December 31, 2007 and 2006.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash inflow stream, such an asset is tested individually and an impairment is recorded if the future cash inflows are no longer sufficient to recover the economic value of the generating facility. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of a regulated asset's economic value, including a fair return on capital, is provided through customer gas and electricity rates approved by the respective regulatory authorities. The cash inflows for regulated enterprises are not asset specific but are pooled for the entire regulated enterprise.

Investments

Portfolio investments are accounted for on the cost basis. Declines in value considered to be other than temporary are recorded in the period in which such determinations are made.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs, or if circumstances change, that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the years ended December 31, 2007 and 2006.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. The accrued benefit obligation and the value of pension costs of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees.

With the exception of Terasen and Newfoundland Power, pension plan assets are valued at fair value. At Terasen and Newfoundland Power, plan assets are valued using the market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at Terasen and Newfoundland Power), at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively applied Section 3461 of the Canadian Institute of Chartered Accountants' ("CICA") Handbook. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit and defined contribution pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 (ix) and (xvi)).



Other Post-Employment Benefit ("OPEB") Plans

The Corporation, Terasen, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits through defined benefit plans, including certain health and dental coverage, for qualifying members.

Additionally, the Corporation, Terasen, FortisAlberta, Newfoundland Power and Maritime Electric provide retirement allowances and supplemental retirement plans for certain of its executive employees. The accrued benefit obligation and the value of the costs associated with these OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the benefit obligation, at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

As approved by the respective regulators, the costs of OPEB plans at FortisAlberta and Newfoundland Power are recovered in customer rates based on the cash payments made, with the exception of retirement allowances arising from Newfoundland Power's 2005 Early Retirement Program. The costs of supplemental pension plans at FortisAlberta are also recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for OPEB and supplemental pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 (iii)).

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options granted under the Corporation's 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 15). Compensation expense is measured at the date of grant using the Black-Scholes fair value option pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option price and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity.

The Corporation also records compensation expense associated with its Directors' Deferred Share Unit ("DSU") and Restricted Share Unit ("RSU") Plans using the fair value method, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU and RSU liabilities is based on the Corporation's Common Share close price at the end of each reporting period.

Foreign Currency Translation

The assets and liabilities of foreign operations, all of which are self-sustaining, are translated at the exchange rate in effect at the balance sheet dates. The exchange rate in effect at December 31, 2007 was US\$1.00 = CDN\$0.99 (December 31, 2006 – US\$1.00 = CDN\$1.17). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity within accumulated other comprehensive income (loss) and the current period change is recorded in the statement of comprehensive income (loss). Revenue and expense items are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are recorded separately in the statement of comprehensive income (loss).

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the balance sheet date. Revenue and expense items denominated in foreign currencies are translated into Canadian dollars at the exchange rate prevailing on the transaction date. Gains and losses on translation are included in the statement of earnings.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

2. Summary of Significant Accounting Policies (cont'd)

Financial Instruments

Effective January 1, 2007, the Corporation adopted Section 3855, *Financial Instruments – Recognition and Measurement* and Section 3861, *Financial Instruments – Disclosure and Presentation*.

The Corporation designates its financial instruments into one of the following five categories: (i) held for trading, (ii) available for sale, (iii) held to maturity, (iv) loans and receivables, or (v) other financial liabilities. All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value with any change in fair value recorded in earnings and other comprehensive income (loss), respectively. All other financial instruments are subsequently measured at amortized cost.

All derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value with changes in fair value recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income (loss). Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the rate-regulated utilities, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates (Note 4).

Currently, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships".

The Corporation has selected January 1, 2003 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantially modified on or after January 1, 2003. While some of the Corporation's long-term debt contracts have prepayment options that qualify as embedded derivatives to be separately recorded, none have been recorded, as they are immaterial to the Corporation's results of operations and financial position.

The Corporation's policy is to recognize transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

Hedging Relationships

Effective January 1, 2007, the Corporation adopted Section 3865, *Hedges*.

At December 31, 2007, the Corporation's hedging relationships consisted of interest rate swap contracts, natural gas commodity swap and option contracts, and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

Fortis Properties and the Terasen Gas companies have designated their interest rate swap contracts as hedges of the cash flow risk related to floating-rate debt. The interest rate swap contracts are valued at the present value of future cash flows based on published forward future interest rate curves. The fair value and subsequent changes in fair value of Fortis Properties' interest rate swap contracts that are in effective hedging relationships are recorded in other comprehensive income (loss). Any changes in the fair value of the interest rate swaps of the Terasen Gas companies, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices and natural gas commodity swaps and options are used, therefore, to fix the effective purchase price of natural gas. As at December 31, 2007, none of the natural gas commodity swaps and options were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas commodity swaps and options, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator. The fair values of the natural gas commodity swaps and options reflect the estimated amounts that the Terasen Gas companies would pay to terminate the contracts as at December 31, 2007.



The Corporation's foreign net investments are exposed to changes in the US dollar exchange rate and the Corporation has reduced its exposure to foreign currency exchange rate fluctuations on a substantial portion of its foreign net investments through the use of US dollar borrowings. The Corporation has designated its US dollar-denominated long-term debt as a hedge of the foreign currency exchange risk related to its net investments in US dollar-denominated self-sustaining foreign operations. In the hedge of net investments in self-sustaining foreign operations, the unrealized gains and losses on the translation of the US dollar-denominated long-term debt serve to offset unrealized foreign currency exchange gains and losses on foreign net investments. The unrealized foreign currency exchange gains and losses on the US dollar-denominated long-term debt and the foreign net investments are recognized in other comprehensive income (loss).

Income Taxes

Except as described below for the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, the Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted and substantively enacted tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense (recovery) is recognized for the estimated income taxes payable (receivable) in the current year.

The Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power follow the taxes-payable method of accounting for income taxes, as prescribed by their respective regulator. Under this methodology, current customer rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable.

Entities not subject to rate regulation generally recognize future income tax assets and liabilities for temporary differences between the tax and accounting basis of all assets and liabilities. In the absence of rate regulation, future income tax assets and liabilities are recorded and the Corporation's future income tax liabilities and future income tax assets would have increased by approximately \$344 million and \$29 million, respectively, at December 31, 2007 (December 31, 2006 – \$127 million and \$56 million, respectively).

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenues. Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the term of the 50-year power purchase agreement.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future.

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's regulatory authority. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authorities and is generally bundled to include service associated with generation, transmission and distribution, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

As required by the respective regulatory authorities, revenue from the sale of gas and electricity by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on the accrual basis. Gas and electricity is metered upon delivery to customers and is recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity that is consumed but not yet billed to customers is estimated and accrued as revenue at each period end.

As required by the PUC, revenue from the sale of electricity by Belize Electricity is recognized as monthly billings are rendered to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis is recorded on the balance sheet as a regulatory liability (Note 4 (xv)).

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

2. Summary of Significant Accounting Policies (cont'd)

Revenue Recognition (cont'd)

FortisAlberta reports revenues and expenses related to transmission services on a net basis in other revenue. At the Corporation's other regulated utilities, transmission revenues and expenses are recorded on a gross basis. As stipulated by the AUC, FortisAlberta is required to arrange and pay for transmission service with AESO and collect transmission revenue from its customers, which is done through invoicing the customers' retailers through FortisAlberta's transmission component of its AUC-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. The rates collected are based on forecasted transmission expenses and, for certain elements of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either collected, or refunded, in future customer rates (Note 4 (v)).

FortisOntario's regulated operations are primarily comprised of the operations of Cornwall Electric and Canadian Niagara Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power are not bundled. At Canadian Niagara Power, the cost of power and transmission are a flow through to customers and these costs, and revenue associated with the recovery of these costs, are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario as required under OEB regulation. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generating operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements. Generally, production from the Corporation's generating stations is metered at or near month end and production data is used to record revenue earned.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements. The leases are primarily of a net nature, with tenants paying basic rental plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue.

The escalation of lease rates included in long-term leases is recorded in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations ("AROs")

AROs are recorded as a liability at fair value, with a corresponding increase to utility capital assets and income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of a fair value can be determined.

The Corporation has AROs associated with hydroelectric generating facilities, and with interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time.

No significant environmental issues have been identified to date in respect of the Corporation's hydroelectric generating facilities. These facilities are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and to ensure the continued provision of electricity service to customers. In the event that environmental issues are identified, hydroelectric generating facilities are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights of way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of removal costs cannot be reasonably determined at this time.

The Corporation has determined that an ARO exists regarding the remediation of leased land on which a pumphouse is currently situated at Maritime Electric. The pumphouse is integral to the Company's operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of fair value of remediation costs cannot be reasonably determined at this time. An ARO associated with land remediation will be recorded when the lease is terminated at the request of the lessor and the costs are reasonably estimable.



On April 1, 2006, Fortis retroactively adopted Emerging Issues Committee Abstract EIC 159, *Conditional Asset-Retirement Obligations* ("EIC 159"). EIC 159 requires an entity to recognize a liability for the fair value of an ARO even though the timing and/or method of settlement are conditional on future events. While conditional AROs have been identified, no amounts have been recorded as they are immaterial to the Corporation's results of operations and financial position.

Accounting Changes

Effective January 1, 2007, the Corporation adopted the revised Section 1506, *Accounting Changes*, relating to changes in accounting policies, changes in accounting estimates, and errors.

Under revised Section 1506, voluntary changes in accounting policies are made only if they result in the financial statements providing reliable and more relevant information. Additional disclosure is required when the Corporation has not applied a new primary source of Canadian GAAP that has been issued but is not yet effective, as well as when changes in accounting estimates and errors occur. Adoption of this revised standard had no impact on the Corporation's 2007 Consolidated Financial Statements except for the disclosures provided in Note 3.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

3. Future Accounting Pronouncements

International Financial Reporting Standards ("IFRS")

In 2006, the Canadian Accounting Standards Board ("AcSB") published a new strategic plan that will significantly affect financial reporting requirements for Canadian companies. The AcSB strategic plan outlines the convergence of Canadian GAAP with IFRS over an expected five-year transitional period. In February 2008, the AcSB confirmed that the use of IFRS will be required in 2011 for publicly accountable profit-oriented enterprises. The transition date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010. While Fortis has begun assessing the adoption of IFRS for 2011, the financial reporting impact on the Corporation of the transition to IFRS cannot be reasonably estimated at this time.

Rate-Regulated Operations

In August 2007, the AcSB issued a Decision Summary that supported the removal of the temporary exemption in Section 1100, *Generally Accepted Accounting Principles*, of the CICA Handbook, providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation. The AcSB also amended Section 3465, *Income Taxes*, to recognize future income tax liabilities and assets as well as offsetting regulatory assets and liabilities at entities subject to rate regulation. Both changes will apply prospectively for the Corporation beginning on January 1, 2009. The AcSB also decided that the current guidance for rate-regulated operations pertaining to property, plant and equipment, disposal of long-lived assets and discontinued operations, and consolidated financial statements be maintained, and that the existing Accounting Guideline 19, *Disclosures by Entities Subject to Rate Regulation*, will not be withdrawn from the Handbook but that the guidance will be updated as a result of the other changes. The AcSB also decided that the final Background Information and Basis for Conclusions associated with its rate-regulation project would not express any views of the AcSB regarding the status of US Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, as "another source of GAAP" within the Canadian GAAP hierarchy.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

3. Future Accounting Pronouncements (cont'd)

Rate-Regulated Operations (cont'd)

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes*, will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the taxes-payable method of accounting for income taxes. The effect on the Corporation's Consolidated Financial Statements, if it had adopted amended Section 3465, *Income Taxes*, as at December 31, 2007, would have been an increase in future tax assets and future tax liabilities of \$54 million and \$489 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of \$54 million and \$489 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates, and the separate disclosure of future income tax assets and liabilities that are currently not recognized. Fortis is continuing to assess and monitor any additional implications on its financial reporting related to accounting for rate-regulated operations.

Inventories

Effective January 1, 2008, the Corporation will be adopting the new Section 3031, *Inventories*. The new standard requires inventories to be measured at the lower of cost or net realizable value; disallows the use of a last-in, first-out inventory-costing methodology; and requires that, when circumstances which previously caused inventories to be written down below cost no longer exist, the amount of the write-down is to be reversed. This new standard is not expected to have a material impact on the Corporation's earnings, cash flow or financial position.

Capital Disclosures

As a result of new Section 1535, *Capital Disclosures*, Fortis will be required to include additional information in the Notes to the Consolidated Financial Statements about its capital and the manner in which it is managed. This additional disclosure includes quantitative and qualitative information regarding an entity's objectives, policies and processes for managing capital. This Section is applicable to Fortis for the fiscal year beginning on January 1, 2008.

Disclosure and Presentation of Financial Instruments

New accounting recommendations for disclosure and presentation of financial instruments, Sections 3862 and 3863, are effective for the Corporation beginning on January 1, 2008. The new recommendations require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed.

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues associated with certain costs incurred in the current or prior periods that will be or are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be or are expected to be refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Based on previous, existing or expected future regulatory orders or decisions, the Corporation has recorded the following amounts expected to be recovered from, or refunded to, customers in future periods.

Regulatory Assets

<i>(in millions)</i>	2007	2006	Remaining recovery period (Years)
Rate stabilization accounts – Terasen Gas companies <i>(i)</i>	\$ 99	\$ –	1–3
Rate stabilization accounts – electric utilities <i>(ii)</i>	55	44	Various
Regulatory OPEB asset <i>(iii)</i>	44	36	Various
Income taxes recoverable on OPEB plans <i>(iv)</i>	16	–	Various
AESO charges deferral <i>(v)</i>	8	40	2
Deferred capital asset amortization <i>(vi)</i>	12	6	1–3
Weather normalization account <i>(vii)</i>	11	12	Not determinable
Residential unbundling <i>(viii)</i>	9	–	1–3
Deferred pension costs <i>(ix)</i>	8	9	8
Southern Crossing Pipeline tax reassessment <i>(x)</i>	7	–	Not determinable
Energy management costs <i>(xi)</i>	6	6	8
Lease costs <i>(xii)</i>	5	4	16–28
Other regulatory assets <i>(xiii)</i>	32	14	1–28
Total regulatory assets	312	171	
Less: current portion	(119)	(31)	1
Long-term regulatory assets	\$ 193	\$ 140	

Regulatory Liabilities

<i>(in millions)</i>	2007	2006	Remaining settlement period (Years)
Future removal and site restoration provision <i>(xiv)</i>	\$ 319	\$ 307	Not determinable
Unbilled revenue liability <i>(xv)</i>	22	25	Not determinable
Pension deferral <i>(xvi)</i>	6	4	1–7
PBR incentive liabilities <i>(xvii)</i>	14	3	1–2
Other regulatory liabilities <i>(xviii)</i>	31	20	1–5
Total regulatory liabilities	392	359	
Less: current portion	(20)	(19)	1
Long-term regulatory liabilities	\$ 372	\$ 340	

Description of the Nature of Regulatory Assets and Liabilities

(i) Rate Stabilization Accounts – Terasen Gas companies

The rate stabilization accounts at the Terasen Gas companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility, caused principally by weather, and natural gas cost volatility. At TGI, a Revenue Stabilization Adjustment Mechanism (“RSAM”) accumulates the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers.

Additionally, a Commodity Cost Reconciliation Account (“CCRA”) and Midstream Cost Reconciliation Account (“MCRA”) accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The MCRA captures the gas cost variances applicable to all sales customers while the CCRA accumulates gas cost variances applicable to all residential customers and certain industrial customers for whom TGI acquires gas supply.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

4. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(i) Rate Stabilization Accounts – Terasen Gas companies (cont'd)

At TGV, a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on TGV's earnings of natural gas cost volatility. TGV also maintains a Revenue Deficiency Deferral Account ("RDDA") to accumulate unrecovered costs of providing service to customers or to draw down such costs where earnings exceed an allowed ROE as set by the BCUC. The RDDA has accumulated the allowed earnings in excess of achieved earnings prior to 2003 and is to be recovered through future rates. During 2007, the RDDA has decreased as achieved earnings have exceeded the allowed ROE.

The RSAM is anticipated to be recovered through rates over a three-year period, with a total balance outstanding at December 31, 2007 of \$18 million. The MCRA, CCRA and GCVA accounts are anticipated to be fully recovered within the next fiscal year. Recovery of the rate stabilization accounts is dependent on actual natural gas consumption and recovery amounts approved by the BCUC.

(ii) Rate Stabilization Accounts – Electric Utilities

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos) are recovered or refunded through customer rates as approved by the respective regulatory authorities. The rate stabilization accounts primarily mitigate the effect on earnings of the variability in the cost of fuel and/or purchased power above or below a forecast or pre-determined level. Additionally, in the case of Belize Electricity, a rate stabilization account is used to defer and recover hurricane damage and recovery expenses from customers. The recovery period of the rate stabilization accounts is variable and is subject to periodic review by the respective regulatory authorities.

On July 1st of each year, the rate charged to Newfoundland Power's customers is recalculated in order to amortize, over the subsequent 12 months, the balance in its rate stabilization account as of December 31st of the previous year. In the absence of rate regulation, the costs deferred to Newfoundland Power's rate stabilization account would continue to be accounted for in a similar manner; however, the amount recovered and the recovery period would not be subject to regulatory approval.

The rate of recovery of the Cost of Power Rate Stabilization Account ("CPRSA") and Hurricane Cost Recovery Rate Stabilization Account ("HCRSA") at Belize Electricity is recalculated on July 1st of each year based on the balance in the CPRSA and HCRSA as of the preceding year end, but may be adjusted at any time as a result of a threshold event.

As at December 31, 2007, \$14 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of \$2 million per year over a recovery period of seven years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling 12-month period.

Except as described for Newfoundland Power, in the absence of rate regulation, the cost of fuel and/or purchased power would be expensed as incurred.

(iii) Regulatory OPEB Asset

At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, the cash cost of providing OPEB plans is being collected in customer rates as permitted by their respective regulators. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC is based on cash costs plus a partial recovery of the full accrual cost of OPEB plans.

The regulatory OPEB asset represents the deferred portion of the benefit expense at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. In the absence of rate regulation, the benefit expense would be recognized on an accrual basis as actuarially determined with no deferral of costs recorded on the balance sheet. FortisAlberta and FortisBC's regulatory OPEB assets are not subject to a regulatory return.

(iv) Income Taxes Recoverable on OPEB Plans

At TGI, the regulator allows OPEB costs to be collected in customer gas rates on an accrual basis, rather than on a cash basis, which produces timing differences for income tax purposes. Since TGI accounts for income taxes using the taxes-payable method, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer gas rates. In the absence of rate regulation, the income tax would not be deferred.

(v) *AESO Charges Deferral*

FortisAlberta maintains an AESO Charges Deferral Account that represents expenses incurred in excess of revenues collected for various items, such as transmission costs incurred and billed through to customers, that are subject to deferral to be collected in future customer rates. In the event that the amount of revenue collected in rates for these items exceeds actual costs incurred, the excess is deferred as a regulatory liability to be either refunded to customers through a reduction in future rates or recognized when additional costs are incurred. As approved by the AUC, \$13 million of the December 31, 2006 AESO Charges Deferral Account balance was collected from customers during 2007. As at December 31, 2007, the balance of the AESO Charges Deferral Account is expected to be collected in customer rates through 2008 and 2009. In the absence of rate regulation, the costs would be expensed as incurred and no deferral treatment would be permitted.

During 2007, FortisAlberta sold approximately \$28 million and \$38 million of the 2006 and 2007 AESO Charges Deferral Accounts, respectively, to a Canadian chartered bank for proceeds of approximately \$28 million and \$38 million, respectively. Proceeds included cash consideration of \$64 million and receivables of approximately \$2 million due in February 2009 and 2010 (Note 5).

(vi) *Deferred Capital Asset Amortization*

Newfoundland Power deferred the recovery of a \$6 million increase in capital asset amortization in each of 2006 and 2007, in accordance with a PUB order. The approximate \$12 million balance at December 31, 2007 will be amortized as an increase in operating expenses and included in customer rates equally over the next three years. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded.

(vii) *Weather Normalization Account*

The PUB has ordered the provision of a weather normalization account at Newfoundland Power to adjust for the effect of variations in weather conditions when compared to long-term averages. This reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from such fluctuations in revenue and purchased power. The balance in the weather normalization account should approach to zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB, approximately \$7 million of the weather normalization account is to be amortized equally over 2008 through 2012. In the absence of rate regulation, these fluctuations would be recorded in earnings in the period in which they occurred.

The recovery period of the remaining balance of the weather normalization account is not determinable as it depends on weather conditions in the future.

(viii) *Residential Unbundling*

Residential unbundling costs are related to costs incurred by TGI to develop a third-party marketer alternative for residential customers to purchase natural gas from suppliers other than TGI. The BCUC approved the deferral of these costs and the recovery of these costs over a three-year period. The balance at December 31, 2007 will be recovered from customers commencing in 2008. In the absence of rate regulation, these costs would have been expensed when incurred.

(ix) *Deferred Pension Costs*

Deferred pension costs are incremental pension costs arising from Newfoundland Power's 2005 Early Retirement Program that were deferred and are being amortized over a 10-year period that began on April 1, 2005, as ordered by the PUB. In the absence of rate regulation, these costs would have been expensed in 2005.

(x) *Southern Crossing Pipeline Tax Reassessment*

The Southern Crossing Pipeline tax-reassessment deferral relates to an assessment of additional British Columbia Social Services Tax, for which TGI has filed an appeal. In 2006, the Company made a payment of \$10 million pending resolution of the appeal as a good faith payment. During 2007, the assessment was reduced to \$7 million and the overpayment was refunded to TGI. Depending on the success of the appeal, TGI will either be refunded the balance or, alternatively, expects to recover the costs from customers in future rates. In the absence of rate regulation, the payment would continue to be recorded as a receivable pending resolution of the appeal. Any final assessed tax upon resolution of the appeal would be expensed in the period it becomes known (Note 26).

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

4. *Regulatory Assets and Liabilities (cont'd)*

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xi) *Energy Management Costs*

FortisBC provides energy management services to promote energy-efficiency programs to its customers. As required by a BCUC order, the Company has capitalized all related expenditures (except certain defined costs) and is amortizing these expenditures on a straight-line basis at 12.5 per cent per annum. This regulatory asset represents the unamortized balance of the energy management costs, which are expected to be recovered from customers in rates over an average of eight years, based on the terms of the currently approved BCUC order. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(xii) *Lease Costs*

On July 15, 2003, FortisBC began operating the Brilliant Terminal Station ("BTS") under an agreement, the term of which expires in 2056 (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination) (the "BTS Obligation") (Note 10). The agreement provides that FortisBC will pay a charge related to the recovery of the capital cost of the BTS and related operating costs. Costs related to the BTS are not being fully recovered by the Company in current customer rates. The regulatory asset balance represents the deferred portion of the cost of the lease that is expected to be recovered from customers in future rates. In the absence of rate regulation, amortization of the BTS and interest on the BTS Obligation would have been recorded in the period incurred.

Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term (Note 25). The Company is accounting for the lease as an operating lease. The terms of the agreement require increasing stepped lease payments during the lease term. As ordered by the BCUC, FortisBC recovers the Trail office lease payments from customers and records the lease costs on a cash basis. In the absence of rate regulation, the lease costs would be recorded on a straight-line basis.

The regulatory deferred lease costs are not subject to a regulatory return.

(xiii) *Other Regulatory Assets*

Other regulatory assets primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power, FortisOntario and Maritime Electric. The balance is comprised of various items each individually less than \$5 million. As of December 31, 2007, \$22 million of the balance was approved for recovery from customers in future rates, with the remaining balance expected to be approved. The recovery periods range from one to 28 years. As of December 31, 2007, \$4 million (2006 – \$4 million) of the balance was not subject to a regulatory return.

In the absence of rate regulation, the deferrals would not be permitted.

(xiv) *Future Removal and Site Restoration Provision*

As required by the respective regulators, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric attributable to removal and site restoration costs that are expected to be incurred in the future. As required by the respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for these future removal and site restoration costs, net of salvage proceeds. Actual removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. The regulatory liability represents the amount of expected future removal and site restoration costs associated with utility capital assets in service as at the balance sheet date, calculated using current amortization rates as approved by the respective regulators. Any difference between actual costs incurred and those assumed in the collected amounts, and any cumulative adjustments resulting from changes to the regulator-approved amortization rates at which these costs are collected, are reflected in this regulatory liability with the offset recorded as an adjustment to accumulated amortization.

During 2007, the amount included in amortization expense associated with the provision for future removal and site restoration costs was \$33 million (2006 – \$30 million). During 2007, actual removal and site restoration costs, net of salvage proceeds, were \$19 million (2006 – \$4 million). In the absence of rate regulation, removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization expense.

(xv) *Unbilled Revenue Liability*

Belize Electricity records revenue derived from electricity sales on a billed basis (Note 2). Prior to January 1, 2006, Newfoundland Power also recorded revenue from electricity sales on a billed basis. The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is recorded on the balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to the accrual basis, as approved by the PUB. As a result, the \$24 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized on the accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized \$3 million of this regulatory liability in 2007 (2006 – \$3 million). The unamortized balance at December 31, 2007 will be amortized as follows: 2008 – approximately \$7 million, 2009 and 2010 – approximately \$5 million in each year. In the absence of rate regulation, revenue would be recorded on an accrual basis and the deferral of unbilled revenue would not be permitted.

(xvi) *Pension Deferral*

This regulatory liability represents pension surplus at FortisAlberta that has not been reflected in customer rates and will result in a reduction of future customer rates when recognized. When future customer rates are reduced, this liability will be drawn down and reflected as a reduction of pension expense. In the absence of rate regulation, the pension deferral would not be permitted and the amortization of the liability would not have occurred. This regulatory pension deferral is not subject to a regulatory return.

(xvii) *PBR Incentive Liabilities*

TGI and FortisBC's regulatory frameworks include PBR mechanisms that allow for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined by the sharing mechanisms with customers as approved per BCUC orders (Note 2).

TGI's 2007 regulatory PBR incentive liability of \$13 million is expected to be refunded to customers through reduced rates beginning in 2009. FortisBC's 2006 regulatory PBR incentive liability of \$3 million was approved by the BCUC for settlement in 2007 through a reduction in 2007 electricity revenue, with an offsetting increase in other revenue. Based on the current PBR framework, FortisBC's 2007 regulatory PBR incentive liability of \$1 million has been approved by the BCUC for settlement in 2008 through a reduction in 2008 electricity revenue. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xviii) *Other Regulatory Liabilities*

Other regulatory liabilities primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power and Fortis Ontario. The balance is comprised of various items each individually less than \$5 million. As of December 31, 2007, \$15 million of the balance was approved for refund to future customers or reduction in future rates, with the remaining balance expected to be approved. The recovery periods range from one to five years. As of December 31, 2007, \$7 million (2006 – \$10 million) of the balance was not subject to a regulatory return.

In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

In the absence of rate regulation and, therefore, in the absence of recording regulatory assets and liabilities as described above, the total impact on the annual consolidated financial statements would have been as follows:

<i>(in millions)</i>	2007	2006
Decrease in regulatory assets	\$ (303)	\$ (167)
Decrease in regulatory liabilities	(392)	(359)
Decrease in opening retained earnings	(108)	(162)
Increase in revenue	343	18
Increase (decrease) in energy supply costs	340	(15)
Increase in operating expense	62	10
Decrease in amortization expense	(28)	(25)
Increase in finance charges	3	2
(Decrease) increase in corporate taxes	(15)	16

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

5. Deferred Charges and Other Assets

<i>(in millions)</i>	2007	2006
Deferred pension costs <i>(Note 20)</i>	\$ 120	\$ 93
AESO contributions	19	17
Long-term receivables – TGI (due 2040)	7	–
Deferred recoverable and project costs	7	10
Energy management loans	6	4
Corporate income tax deposit	6	6
Investment held as collateral	3	3
Investments	2	2
Long-term receivable – AESO charges deferral <i>(Note 4 (v))</i>	2	–
Other deferred charges	7	7
Deferred financing costs	–	21
Deferred loss on interest rate swap agreement	–	11
	\$ 179	\$ 174

As a result of adopting Section 3855, *Financial Instruments – Recognition and Measurement*, deferred financing costs of \$21 million at January 1, 2007 relating to long-term debt have been reclassified from deferred charges and other assets to long-term debt (Note 10).

As of January 1, 2007, in accordance with the transitional provision of Section 3865, *Hedges*, an unamortized deferred loss balance of \$11 million, related to a previously cancelled interest rate swap agreement, was reclassified from deferred charges and other assets to accumulated other comprehensive loss (Note 16).

6. Utility Capital Assets

2007					
<i>(in millions)</i>	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	\$ 2,233	\$ (364)	\$ (174)	\$ –	\$ 1,695
Electric	3,536	(961)	(463)	(91)	2,021
Transmission					
Gas	1,277	(286)	(102)	–	889
Electric	870	(224)	–	–	646
Generation	915	(240)	–	–	675
Assets under construction	155	–	–	–	155
Other	992	(337)	(14)	–	641
	\$ 9,978	\$ (2,412)	\$ (753)	\$ (91)	\$ 6,722

2006

<i>(in millions)</i>	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Electric Distribution	\$ 3,223	\$ (864)	\$ (426)	\$ (96)	\$ 1,837
Electric Transmission	818	(229)	–	–	589
Generation	903	(245)	–	–	658
Assets under construction	130	–	–	–	130
Other	552	(191)	–	–	361
	\$ 5,626	\$ (1,529)	\$ (426)	\$ (96)	\$ 3,575

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electric distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electric transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires and conductors, substations, support structures and other related equipment.

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

Other assets include land and land rights, buildings, equipment, vehicles and information technology assets.

The cost of utility capital assets under capital lease at December 31, 2007 was \$51 million (2006 – \$27 million) and related accumulated amortization was \$19 million (2006 – \$3 million).

7. Income Producing Properties

2007

<i>(in millions)</i>	Cost	Accumulated Amortization	Net Book Value
Buildings	\$ 469	\$ (42)	\$ 427
Land	54	–	54
Tenant inducements	22	(13)	9
Equipment	46	(18)	28
Construction in progress	1	–	1
	\$ 592	\$ (73)	\$ 519

2006

<i>(in millions)</i>	Cost	Accumulated Amortization	Net Book Value
Buildings	\$ 421	\$ (35)	\$ 386
Land	51	–	51
Tenant inducements	17	(11)	6
Equipment	40	(15)	25
Construction in progress	1	–	1
	\$ 530	\$ (61)	\$ 469

The cost of income producing property assets under capital lease at December 31, 2007 was \$6 million (2006 – \$11 million) and related accumulated amortization was \$4 million (2006 – \$7 million).

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

8. Goodwill

<i>(in millions)</i>	2007	2006
Balance, beginning of year	\$ 661	\$ 512
Acquisition of Terasen <i>(Note 21)</i>	907	–
Reversal of restructuring accrual	(2)	–
Acquisition of controlling interest in Caribbean Utilities <i>(Note 21)</i>	–	106
Acquisition of Fortis Turks and Caicos <i>(Note 21)</i>	–	39
Foreign exchange translation impacts	(22)	4
Balance, end of year	\$ 1,544	\$ 661

Goodwill associated with the acquisition of a controlling interest in Caribbean Utilities on November 7, 2006 and the acquisition of Fortis Turks and Caicos on August 28, 2006 is denominated in US dollars as the investment in these companies is held through a wholly owned subsidiary of Fortis with a reporting currency in US dollars. Foreign currency translation impacts in 2007 and 2006 were the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

9. Credit-Facility Borrowings

The credit facilities of the Corporation and its subsidiaries, as summarized below, bear interest at rates ranging from 4.6 per cent to 6.2 per cent at December 31, 2007 (December 31, 2006 – 4.5 per cent to 6.8 per cent). As at December 31, 2007, the Corporation and its subsidiaries had consolidated authorized lines of credit of \$2.2 billion, of which \$1.1 billion was unused.

<i>(in millions)</i>	Corporate and Other	Regulated Utilities	Fortis Properties	Total as at December 31, 2007	Total as at December 31, 2006
Total credit facilities	\$ 715	\$ 1,506	\$ 13	\$ 2,234	\$ 952
Credit facilities utilized					
Short-term borrowings	(6)	(468)	(1)	(475)	(98)
Long-term debt <i>(Note 10)</i>	(208)	(322)	–	(530)	(235)
Letters of credit outstanding	(55)	(103)	(1)	(159)	(72)
Credit facilities available	\$ 446	\$ 613	\$ 11	\$ 1,070	\$ 547

At December 31, 2007 and December 31, 2006, certain borrowings under the Corporation's and subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Corporate and Other

At December 31, 2007, Terasen Inc. had a \$100 million unsecured committed revolving credit facility, maturing in May 2009 that is available for general corporate purposes. Letters of credit outstanding of \$55 million at Terasen Inc., related to its previously owned petroleum transportation business, are secured by a letter of credit from the former parent company.

During 2007, Fortis cancelled its \$50 million unsecured revolving committed credit facility, and renegotiated and amended its \$250 million unsecured committed credit facility, extending the maturity date to May 2012 and increasing the amount available to \$600 million. Fortis also has a \$15 million unsecured demand facility.



Regulated Utilities

At December 31, 2007, TGI had a \$500 million unsecured committed revolving credit facility maturing in August 2012. At December 31, 2007, TGI had a \$350 million unsecured committed revolving credit facility, maturing in January 2011. These facilities are utilized to finance working capital requirements and capital expenditures, and for general corporate purposes. TGI also had a \$20 million subordinated unsecured committed non-revolving credit facility, maturing in January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

In May 2007, FortisAlberta terminated one of its \$10 million unsecured demand credit facilities, leaving one unsecured demand credit facility of \$10 million available to the Company, and the maturity date of FortisAlberta's \$200 million unsecured committed credit facility was extended to May 2012 from May 2010. The \$200 million facility is utilized to finance capital expenditures and for general corporate purposes, and with the consent of the lenders, the amount of the facility can be increased to \$250 million.

In May 2007, FortisBC renegotiated and amended its \$150 million unsecured committed revolving credit facility, reallocating the amounts available between the 364-day portion of the facility and the three-year portion of the facility, and extending the maturity date for the three-year facility to May 2010 from May 2008. Additionally, the Company has the option to increase the credit facility to an aggregate of \$200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC also has a \$10 million unsecured demand facility.

Newfoundland Power has unsecured credit facilities of \$120 million, comprised of a \$100 million committed revolving credit facility which matures in January 2009 and a \$20 million uncommitted demand facility.

During 2007, Maritime Electric increased its unsecured revolving credit facility to \$45 million from \$30 million. Maritime Electric also has a \$25 million unsecured credit facility maturing in May 2008.

FortisOntario has secured lines of credit totalling \$16 million, of which \$10 million is authorized solely for letters of credit.

On November 27, 2006, Caribbean Utilities renegotiated its credit facilities, increasing its capital expenditures line of credit from US\$13 million to US\$19 million, including amounts available for letters of credit, and increasing each of its US\$5 million operating line of credit and US\$5 million catastrophe standby loan to US\$7.5 million.

In November 2007, Fortis Turks and Caicos increased its operating credit facilities to US\$5 million from US\$2 million and obtained a US\$7 million capital expenditure line of credit. Fortis Turks and Caicos also has available a US\$9 million emergency standby loan.

Belize Electricity has a BZ\$11 million unsecured demand overdraft credit facility.

Fortis Properties

Fortis Properties has a \$13 million secured revolving demand facility utilized for general corporate purposes.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

10. Long-Term Debt and Capital Lease Obligations

<i>(in millions)</i>	2007	2006
Regulated Utilities		
<i>Terasen Gas companies</i>		
<i>Secured Purchase Money Mortgages:</i>		
11.80% \$75 million Series A, due 2015	\$ 75	\$ —
10.30% \$200 million Series B, due 2016	200	—
<i>Unsecured Debentures:</i>		
10.75% \$60 million Series E, due 2009	60	—
6.20% \$188 million Series 9, due 2008	188	—
6.95% \$150 million Series 11, due 2029	150	—
6.50% \$150 million Series 18, due 2034	150	—
5.90% \$150 million Series 19, due 2035	150	—
5.55% \$120 million Series 21, due 2036	120	—
6.00% \$250 million Series 22, due 2037	250	—
\$6 million repayable Government loan, due 2008	6	—
Obligation under capital lease, due 2012	9	—
	1,358	—
<i>FortisAlberta</i>		
5.33% \$200 million Senior Unsecured Debentures, due 2014	200	200
6.22% \$200 million Senior Unsecured Debentures, due 2034	200	200
5.40% \$100 million Senior Unsecured Debentures, due 2036	100	100
4.99% \$110 million Senior Unsecured Debentures, due 2047	110	—
	610	500
<i>FortisBC</i>		
<i>Secured Debentures:</i>		
11.00% \$15 million Series E, due 2009	5	5
9.65% \$15 million Series F, due 2012	15	15
8.80% \$25 million Series G, due 2023	25	25
<i>Unsecured Debentures:</i>		
6.75% \$50 million Series J, due 2009	50	50
5.48% \$140 million Series 04-1, due 2014	140	140
8.77% \$25 million Series H, due 2016	25	25
7.81% \$25 million Series I, due 2021	25	25
5.60% \$100 million Series 05-1, due 2035	100	100
5.90% \$105 million Series 07-1, due 2047	105	—
Obligation under capital lease, due 2032	26	27
	516	412

<i>(in millions)</i>	2007	2006
<i>Newfoundland Power</i>		
<i>Secured first mortgage sinking fund bonds:</i>		
11.875% \$40 million Series AC, due 2007	–	32
10.550% \$40 million Series AD, due 2014	31	32
10.900% \$40 million Series AE, due 2016	34	34
9.000% \$40 million Series AG, due 2020	35	35
10.125% \$40 million Series AF, due 2022	34	34
8.900% \$40 million Series AH, due 2026	36	36
6.800% \$50 million Series AI, due 2028	46	46
7.520% \$75 million Series AJ, due 2032	71	72
5.441% \$60 million Series AK, due 2035	58	59
5.901% \$70 million Series AL, due 2037	69	–
	414	380
<i>Maritime Electric</i>		
<i>Secured first mortgage bonds:</i>		
12.000% \$15 million, due 2010	15	15
11.500% \$12 million, due 2016	12	12
8.550% \$15 million, due 2018	15	15
7.570% \$15 million, due 2025	15	15
8.625% \$15 million, due 2027	15	15
8.920% \$20 million, due 2031	20	20
	92	92
<i>FortisOntario</i>		
7.092% \$30 million Senior Unsecured Notes, due 2018	30	30
7.092% \$22 million Senior Unsecured Notes, due 2018	22	22
	52	52
<i>Belize Electricity</i>		
<i>Secured:</i>		
5.75% to 8.15% US\$14 million RBTT Merchant Bank loan, due 2010 to 2012 (December 31, 2007 – US\$6 million)	6	9
<i>Unsecured:</i>		
12.00% BZ\$27 million Series I Debentures, due 2012 (December 31, 2007 – BZ\$17 million)	8	10
9.50% BZ\$20 million Series II Debentures, due 2021 (December 31, 2007 – BZ\$19 million)	10	11
10.00% BZ\$25 million Series III Debentures, due 2022 (December 31, 2007 – BZ\$25 million)	12	14
10.00% BZ\$6 million Series IV Debentures, due 2027 (December 31, 2007 – BZ\$6 million)	3	–
8.50% US\$16 million Caribbean Development Bank loan, due 2014 (December 31, 2007 – US\$7 million)	7	9
5.00% Euro\$4 million European Investment Bank loan, due 2014 (December 31, 2007 – Euro\$4 million)	3	3
US\$11 million International Bank for Reconstruction and Development loan ("IBRD"), due 2011 (December 31, 2007 – US\$3 million)	3	5
5.75% US\$5 million Toronto Dominion Bank loan, due 2009 (December 31, 2007 – US\$1 million)	1	3
BZ\$10 million Bank of Nova Scotia loan, due 2015 (December 31, 2007 – BZ\$9 million)	4	3
US\$3 million Scotiabank & Trust (Cayman) Limited loan, due 2010 (December 31, 2007 – US\$3 million)	3	4
	60	71

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

10. Long-Term Debt and Capital Lease Obligations (cont'd)

(in millions)	2007	2006
<i>Caribbean Utilities</i>		
<i>Unsecured:</i>		
3.00% US\$2 million European Investment Bank Loan #3, due 2009 (December 31, 2007 – US\$1 million)	1	1
8.47% US\$15 million Senior Loan Notes, due 2010 (December 31, 2007 – US\$4 million)	4	7
6.47% US\$25 million Senior Loan Notes, due 2013 (December 31, 2007 – US\$15 million)	15	20
7.64% US\$30 million Senior Loan Notes, due 2014 (December 31, 2007 – US\$21 million)	21	28
6.67% US\$30 million Senior Loan Notes, due 2016 (December 31, 2007 – US\$26 million)	26	35
5.09% US\$40 million Senior Loan Notes, due 2018 (December 31, 2007 – US\$40 million)	40	47
5.96% US\$30 million Senior Loan Notes, due 2020 (December 31, 2007 – US\$30 million)	30	35
5.65% US\$40 million Senior Loan Notes, due 2022 (December 31, 2007 – US\$40 million)	40	–
	177	173
<i>Fortis Turks and Caicos</i>		
<i>Unsecured:</i>		
5.65% US\$5 million First Caribbean International Bank loan, due 2015 (December 31, 2007 – US\$3 million)	3	6
US\$13 million Scotiabank (Turks and Caicos) Ltd. loan, due 2013 to 2016 (December 31, 2007 – US\$13 million)	13	17
	16	23
Non-Regulated – Fortis Generation		
<i>Secured:</i>		
<i>BECOL</i>		
US\$45 million Term loan, due 2011	–	33
<i>Exploits Partnership</i>		
7.55% \$65 million Term loan, due 2028	62	63
<i>Walden Power Partnership</i>		
9.44% \$10 million WPP Mortgage, due 2013	5	6
	67	102

<i>(in millions)</i>	2007	2006
Non-Regulated – Fortis Properties		
<i>Secured:</i>		
6.42% \$15 million First mortgage, due 2007	–	4
6.85% \$5 million First mortgage, due 2007	–	5
5.10% \$30 million First mortgage, due 2010	27	28
5.35% \$12 million First mortgage, due 2010	11	12
8.15% \$21 million First mortgage, due 2010	15	15
9.47% \$13 million First mortgage, due 2010	10	11
7.42% \$29 million First mortgage, due 2012	25	25
7.77% \$23 million First mortgage, due 2012	20	21
6.58% \$35 million First mortgage, due 2013	30	31
7.30% \$30 million First mortgage, due 2013	27	28
6.42% \$16 million First mortgage, due 2014	15	15
7.50% \$50 million First mortgage, due 2017	40	41
7.32% \$22 million Senior notes, due 2019	17	18
Obligation under capital leases, due 2008 and 2012	2	3
Non-revolving credit facilities, due 2009 to 2010	7	8
	246	265
Corporate and Other		
<i>Fortis Inc.</i>		
7.40% \$100 million Senior Unsecured Debentures, due 2010	100	100
6.75% US\$10 million Unsecured Subordinated Convertible Debentures, due 2012 (December 31, 2007 – US\$6 million)	6	11
5.50% US\$10 million Unsecured Subordinated Convertible Debentures, due 2013 (December 31, 2007 – US\$4 million)	4	11
5.74% US\$150 million Senior Unsecured Notes, due 2014 (December 31, 2007 – US\$150 million)	149	175
5.50% US\$40 million Unsecured Subordinated Convertible Debentures, due 2016 (December 31, 2007 – US\$40 million)	35	41
6.60% US\$200 million Senior Unsecured Notes, due 2037 (December 31, 2007 – US\$200 million)	198	–
	492	338
<i>Terasen Inc.</i>		
6.30% \$200 million Unsecured Debentures, due 2008	203	–
5.56% \$125 million Unsecured Debentures, due 2014	133	–
8.00% \$125 million Capital Securities, due 2040	126	–
	462	–
Long-term classification of credit facilities (Note 9)	530	235
Total long-term debt and capital lease obligations	5,092	2,643
Deferred financing costs	(33)	–
Less: Current installments of long-term debt and capital lease obligations	(436)	(85)
	\$ 4,623	\$ 2,558

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

10. Long-Term Debt and Capital Lease Obligations (cont'd)

Regulated Utilities

Terasen Gas companies

The purchase money mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on TGI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be used is limited to \$425 million.

On October 2, 2007, TGI issued \$250 million 6.00% medium-term note debentures. The debentures mature on October 2, 2037 and are unsecured. The proceeds were used to repay Series 13 and Series 20 medium-term note debentures of TGI, which matured in 2007.

With the exception of the \$250 million 6.00% debentures, the purchase money mortgages and unsecured debentures were assumed by Fortis upon acquisition of the Terasen Gas companies.

FortisAlberta

On January 3, 2007, FortisAlberta issued a \$110 million 4.99% senior unsecured debenture offering, maturing on January 3, 2047.

FortisBC

The secured Series E, F and G debentures are collateralized by a fixed and floating first charge on the assets of FortisBC. Sinking fund payments of \$0.75 million per year are required for the Series E debentures.

On July 4, 2007, FortisBC issued \$105 million 5.90% senior unsecured debentures, maturing on July 4, 2047.

FortisBC has a capital lease obligation with respect to the BTS (Note 4 (xii)). Future minimum lease payments associated with this capital lease obligation are approximately \$3 million per year over the remaining term of the lease agreement to 2032. The BTS lease obligation bears interest at a composite rate of 8.62 per cent.

Newfoundland Power and Maritime Electric

The Newfoundland Power and Maritime Electric first mortgage bonds are secured by a first fixed and specific charge on the respective utility's capital assets owned or to be acquired and by a floating charge on all other assets.

On August 17, 2007, Newfoundland Power issued \$70 million 5.901% first mortgage sinking fund bonds, maturing on August 17, 2037.

Belize Electricity

The RBTT Merchant Bank loan is secured by a debenture over specific assets of the Company.

The Series I, II, III and IV unsecured debentures can be called by Belize Electricity at any time after certain dates until maturity by giving holders not more than 60 days' nor less than 30 days' written notice, and are repayable at the option of the holders at any time on or after certain dates by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

The IBRD loan bears interest at 0.50 per cent per annum above the bank's "Cost of Qualified Borrowings" as defined in the loan agreement. The effective rate of interest as of December 31, 2007 was 6.89 per cent per annum (December 31, 2006 – 5.35 per cent). The Bank of Nova Scotia loan bears interest at the prevailing six-month London Interbank Offered Rate ("LIBOR") plus 0.50 per cent per annum. The Scotiabank & Trust (Cayman) Limited loan bears interest at the prevailing six-month LIBOR plus 5.00 per cent per annum.

Caribbean Utilities

During 2007, Caribbean Utilities issued a US\$40 million private placement of 5.65% senior unsecured notes due June 1, 2022.

Fortis Turks and Caicos

The Scotiabank (Turks and Caicos) Ltd. debt consists of three loans, bearing interest at a floating rate of 1.00 per cent above LIBOR, a fixed rate of 6.04 per cent per annum and a fixed rate of 6.10 per cent per annum.

Fortis Generation

BECOL

On November 28, 2007, BECOL repaid early the remaining amount on its original US\$45 million term loan. The loan bore interest at the prevailing six-month LIBOR plus 4.00 per cent and was secured by agreements covering all its property assets and undertakings.



Exploits Partnership

A first, fixed and specific charge and security interest over all the assets of the Exploits Partnership and assignment of various agreements has been provided as security on the Exploits Partnership non-recourse 25-year amortizing term loan.

Walden Power Partnership

The WPP mortgage is collateralized by a fixed and floating charge over the assets of the WPP.

Fortis Properties

Fortis Properties' first mortgages are collateralized by a fixed and floating charge on specific income producing properties. The senior secured notes are collateralized by a fixed and specific mortgage and a charge on a specific income producing property.

The non-revolving credit facilities at Fortis Properties, bearing interest at Canadian Bankers' Acceptance rates, are collateralized by specific income producing properties. Fortis Properties is party to two interest rate swap contracts maturing on July 28, 2009 and October 15, 2010, respectively, to hedge against interest exposures on the non-revolving credit facilities. The contracts have the effect of fixing the rate of interest on the non-revolving credit facilities at 5.32 per cent and 6.16 per cent, respectively.

Corporate and Other

Fortis Inc.

The 7.40% senior unsecured debentures are redeemable at the option of the Corporation at a price calculated as the greater of the principal amount to be redeemed and an amount equal to the net present value of interest and principal based on the Canada Yield, plus a premium ranging from 0.43 per cent to 0.87 per cent, together with accrued and unpaid interest thereon.

The 6.75% unsecured subordinated convertible debentures are redeemable by the Corporation at par at any time on or after March 12, 2007, and are convertible, at the option of the holder, into the Corporation's Common Shares at \$9.11 per share (US\$9.19 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The 5.50% unsecured subordinated convertible debentures, due 2013, are redeemable by the Corporation at par at any time on or after May 20, 2008, and are convertible, at the option of the holder, into the Corporation's Common Shares at \$11.87 per share (US\$11.97 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The 5.50% unsecured subordinated convertible debentures, due 2016, are redeemable by the Corporation at par at any time on or after November 7, 2011, and are convertible, at the option of the holder, into the Corporation's Common Shares at \$28.86 per share (US\$29.11 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The unsecured subordinated convertible debentures are being accounted for in accordance with their substance and are presented in the financial statements in their component parts. The liability and equity components are classified separately on the balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was \$6 million at December 31, 2007 (December 31, 2006 – \$7 million).

On September 6, 2007, the Corporation issued US\$200 million 6.60% senior unsecured notes, maturing on September 1, 2037.

Terasen Inc.

The 8.00% capital securities were issued on April 19, 2000. Terasen Inc. may elect to defer payment on these securities and settle such deferred payments in either cash or common shares, and has the option to settle principal at maturity through the issuance of common shares. The Company has the right to redeem the securities at the principal amount, together with accrued and unpaid interest, on or after April 19, 2010. The securities are also exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash.

The unsecured debentures and capital securities were assumed by Fortis upon acquisition of Terasen Inc.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

10. Long-Term Debt and Capital Lease Obligations (cont'd)

Deferred Financing Costs

As a result of adopting Section 3855, *Financial Instruments – Recognition and Measurement*, deferred financing costs of \$21 million as at January 1, 2007 relating to long-term debt were reclassified from deferred charges and other assets to long-term debt and, effective January 1, 2007, any deferred financing costs associated with new debt issuances are now recorded against the debt balances. The deferred financing costs are amortized into earnings using the effective interest rate method over the life of the related debt.

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years are as follows:

2008	\$ 436 million
2009	\$ 191 million
2010	\$ 215 million
2011	\$ 307 million
2012	\$ 321 million

11. Deferred Credits

(in millions)

	2007	2006
OPEB obligations (Note 20)	\$ 112	\$ 51
Supplementary defined benefit obligations (Note 20)	38	12
Deferred gains on sale of natural gas transmission and distribution assets	50	–
Deferred payment	40	–
Customer deposits	5	5
Deferred gain on forward currency swap agreement	–	3
Trail lease costs (Note 4 (xii))	2	2
Other deferred credits	14	6
	\$ 261	\$ 79

The deferred gains on sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of \$71 million on combined cash proceeds of \$141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 25.

The deferred payment resulted from Terasen Inc.'s acquisition of TGVI, effective January 1, 2002. The deferred payment has a face value of \$52 million but was discounted at May 17, 2007 to its present value. At December 31, 2007, its present value was \$40 million. The payment is due on December 31, 2011 or sooner if TGVI realizes revenue from transportation revenue contracts to serve power-generating plants which may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

As of January 1, 2007, in accordance with the transitional provision of Section 3865, *Hedges*, an unamortized deferred gain balance of \$3 million, related to a previously cancelled forward currency swap agreement, was reclassified from deferred credits to accumulated other comprehensive loss (Note 16).

12. Non-Controlling Interest

(in millions)

	2007	2006
Caribbean Utilities	\$ 67	\$ 78
Belize Electricity	38	42
Exploits Partnership	3	3
Preference shares of Newfoundland Power	7	7
	\$ 115	\$ 130

13. Preference Shares

Authorized

- (a) an unlimited number of First Preference Shares, without nominal or par value
- (b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		2007		2006	
	Classification	Number of Shares	Amount (in millions)	Number of Shares	Amount (in millions)
(i) First Preference Shares, Series C	Debt	5,000,000	\$ 123	5,000,000	\$ 123
(ii) First Preference Shares, Series E	Debt	7,993,500	197	7,993,500	197
Total classified as debt		12,993,500	\$ 320	12,993,500	\$ 320
(iii) First Preference Shares, Series F	Equity	5,000,000	\$ 122	5,000,000	\$ 122

(i) First Preference Shares, Series C

The First Preference Shares, Series C are entitled to fixed cumulative preferential cash dividends at a rate of \$1.3625 per share per annum.

On or after June 1, 2010, the Corporation may, at its option, redeem for cash the First Preference Shares, Series C, in whole at any time or in part from time to time, at \$25.75 per share if redeemed before June 1, 2011, at \$25.50 per share if redeemed on or after June 1, 2011 but before June 1, 2012, at \$25.25 per share if redeemed on or after June 1, 2012 but before June 1, 2013, and at \$25.00 per share if redeemed on or after June 1, 2013 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

On or after June 1, 2010, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series C into fully paid and freely tradable Common Shares of the Corporation. The number of common shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per Preference Share, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of \$1.00 and 95 per cent of the then-current market price of the common shares at such time.

On or after September 1, 2013, each First Preference Share, Series C will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradable common shares determined by dividing \$25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of \$1.00 and 95 per cent of the then-current market price of the common shares. If a holder of First Preference Shares, Series C elects to convert any of such shares into common shares, the Corporation can redeem such First Preference Shares, Series C for cash or arrange for the sale of those shares to other purchasers.

As the First Preference Shares, Series C are convertible at the option of the shareholder into a variable number of common shares based on a market-related price of such common shares, they meet the definition of a financial liability and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

(ii) First Preference Shares, Series E

The First Preference Shares, Series E are entitled to receive fixed cumulative preferential cash dividends in the amount of \$1.2250 per share per annum.

On or after June 1, 2013, the Corporation may, at its option, redeem all, or from time to time any part of, the outstanding First Preference Shares, Series E by the payment in cash of a sum per redeemed share equal to \$25.75 if redeemed during the 12 months commencing June 1, 2013, \$25.50 if redeemed during the 12 months commencing June 1, 2014, \$25.25 if redeemed during the 12 months commencing June 1, 2015, and \$25.00 if redeemed on or after June 1, 2016 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

On or after June 1, 2013, the Corporation may, at its option, convert all, or from time to time any part of the outstanding First Preference Shares, Series E into fully paid and freely tradable Common Shares of the Corporation. The number of common shares into which each Preference Share may be so converted will be determined by dividing the then-applicable redemption price per First Preference Share, Series E, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of \$1.00 and 95 per cent of the then-current market price of the common shares at such time.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

13. Preference Shares (cont'd)

(ii) First Preference Shares, Series E (cont'd)

On or after September 1, 2016, each First Preference Share, Series E will be convertible at the option of the holder on the first business day of September, December, March and June of each year, into fully paid and freely tradable common shares determined by dividing \$25.00, together with all accrued and unpaid dividends up to but excluding the date fixed for conversion, by the greater of \$1.00 and 95 per cent of the then-current market price of the common shares. If a holder of First Preference Shares, Series E elects to convert any of such shares into common shares, the Corporation can redeem such First Preference Shares, Series E for cash or arrange for the sale of those shares to other purchasers.

As the First Preference Shares, Series E are convertible at the option of the shareholder into a variable number of common shares based on a market-related price of such common shares, they meet the definition of a financial liability and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

(iii) First Preference Shares, Series F

The First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends in the amount of \$1.2250 per share per annum.

On or after December 1, 2011, the Corporation may, at its option, redeem for cash the First Preference Shares, Series F, in whole at any time or in part from time to time, at \$26.00 per share if redeemed before December 1, 2012, at \$25.75 per share if redeemed on or after December 1, 2012 but before December 1, 2013, at \$25.50 per share if redeemed on or after December 1, 2013 but before December 1, 2014, at \$25.25 per share if redeemed on or after December 1, 2014 but before December 1, 2015, and at \$25.00 per share if redeemed on or after December 1, 2015 plus, in each case, all accrued and unpaid dividends up to but excluding the date fixed for redemption.

As the First Preference Shares, Series F are not redeemable at the option of the shareholder, they are classified as equity and the associated dividends are deducted on the statement of earnings immediately before arriving at net earnings applicable to common shares.

14. Common Shares

Authorized: an unlimited number of Common Shares without nominal or par value.

Issued and Outstanding	2007		2006	
	Number of Shares	Amount (in millions)	Number of Shares	Amount (in millions)
Common Shares	155,521,313	\$ 2,126	104,091,542	\$ 829

Common Shares issued during the year were as follows:

	2007		2006	
	Number of Shares	Amount (in millions)	Number of Shares	Amount (in millions)
Opening balance	104,091,542	\$ 829	103,203,981	\$ 813
Public offering	5,170,000	146	—	—
Public offering – Conversion of Subscription Receipts	44,275,000	1,119	—	—
Conversion of debentures	882,626	9	—	—
Consumer Share Purchase Plan	79,463	3	77,213	2
Dividend Reinvestment Plan	203,763	5	176,264	5
Employee Share Purchase Plan	240,578	6	135,502	3
Stock Option Plans	578,341	9	498,582	6
Ending balance	155,521,313	\$ 2,126	104,091,542	\$ 829

On January 18, 2007, Fortis issued 5,170,000 Common Shares for \$29.00 per common share. The common share issuance resulted in gross proceeds of approximately \$150 million, or approximately \$146 million net of after-tax expenses.

During 2007, holders of the Corporation's 6.75% unsecured subordinated convertible debentures converted US\$4 million of the US\$10 million debentures into 435,490 Common Shares of the Corporation.

During 2007, holders of the Corporation's 5.50% unsecured subordinated convertible debentures converted approximately US\$5 million of the US\$10 million debentures into 447,136 Common Shares of the Corporation.

On March 15, 2007, to finance a significant portion of the net cash purchase price of Terasen, the Corporation sold 44,275,000 Subscription Receipts at \$26.00 each, for gross proceeds of approximately \$1.15 billion. Upon closing of the acquisition of Terasen on May 17, 2007, each Subscription Receipt was exchanged, without payment of additional consideration, for one Common Share of Fortis. Each Subscription Receipt holder also received a cash payment of \$0.21 per Subscription Receipt, which was an amount equal to the dividend declared per Common Share of Fortis to holders of record as of May 4, 2007. The net proceeds to the Corporation upon conversion of the Subscription Receipts were approximately \$1.12 billion, net of after-tax expenses.

At December 31, 2007, 9.9 million Common Shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans.

At December 31, 2007, Common Shares reserved for issuance under the terms of the Corporation's convertible debentures and Preference Shares were 2.4 million and 26 million, respectively.

As at December 31, 2007, \$3 million (December 31, 2006 – \$1 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 137.6 million and 103.6 million at December 31, 2007 and December 31, 2006, respectively.

Diluted earnings per common share are calculated using the treasury stock method for options and the "if-converted" method for convertible securities.

Earnings per common share are as follows:

	2007			2006		
	Earnings (in millions)	Weighted Average Shares (in millions)	Earnings per Common Share	Earnings (in millions)	Weighted Average Shares (in millions)	Earnings per Common Share
Net earnings applicable to common shares	\$ 193			\$ 147		
Weighted average shares outstanding		137.6			103.6	
Basic Earnings per Common Share			\$ 1.40			\$ 1.42
Effect of potential dilutive securities:						
Subscription receipts ⁽¹⁾	–	7.8		–	–	
Stock options	–	1.2		–	1.2	
Preference shares (Notes 13 (i) and (ii) and 17)	16	11.5		17	14.1	
Convertible debentures	3	2.8		1	2.0	
	212	160.9		165	120.9	
Deduct anti-dilutive impacts:						
Convertible debentures	(2)	(1.4)		–	–	
Diluted Earnings per Common Share	\$ 210	159.5	\$ 1.32	\$ 165	120.9	\$ 1.37

⁽¹⁾ Dilution relating to the period the Subscription Receipts were outstanding from March 15, 2007 to May 16, 2007, prior to their conversion into Common Shares.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

15. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis Inc. and its subsidiaries options to purchase Common Shares of the Corporation. At December 31, 2007, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options are exercised or expire in or before 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options are being granted by Fortis Inc. under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years, which is reduced from ten years under the 2002 Plan, and expire no later than three years after the termination, death or retirement of the optionee. Directors are not eligible to receive grants of options under the 2006 Plan. During 2006, the Corporation replaced the equity component of directors' annual compensation with DSUs.

Number of Options:	2007	2006
Options outstanding, beginning of year	3,550,055	3,421,876
Granted	754,800	626,761
Cancelled	(34,743)	–
Exercised	(578,341)	(498,582)
Options outstanding, end of year	3,691,771	3,550,055
Options vested, end of year	1,901,811	1,739,759

Weighted Average Exercise Prices:	2007	2006
Options outstanding, beginning of year	\$ 16.11	\$ 14.18
Granted	27.75	22.94
Cancelled	22.43	–
Exercised	13.35	11.45
Options outstanding, end of year	18.86	16.11

Details of stock options outstanding and vested as at December 31, 2007 are as follows:

Outstanding			Vested		
Number of Options	Exercise Price	Expiry Date	Number of Options	Exercise Price	Expiry Date
112,422	\$ 9.57	2011	112,422	\$ 9.57	2011
302,076	\$ 12.03	2012	302,076	\$ 12.03	2012
527,675	\$ 12.81	2013	527,675	\$ 12.81	2013
626,382	\$ 15.28	2014	457,450	\$ 15.28	2014
12,000	\$ 15.23	2014	7,000	\$ 15.23	2014
33,910	\$ 14.55	2014	19,262	\$ 14.55	2014
683,742	\$ 18.40	2015	316,422	\$ 18.40	2015
28,000	\$ 18.11	2015	14,000	\$ 18.11	2015
31,639	\$ 20.82	2015	14,769	\$ 20.82	2015
590,621	\$ 22.94	2016	130,735	\$ 22.94	2016
606,472	\$ 28.19	2014			
136,832	\$ 25.76	2014			
3,691,771			1,901,811		

The weighted average exercise price of stock options vested as at December 31, 2007 was \$14.84.

On May 7, 2007, the Corporation granted 617,968 options on common shares under its 2006 Plan at the five-day volume weighted average trading price immediately preceding the date of grant of \$28.19. These options vest evenly over a four-year period on each anniversary of the date of grant. The options expire seven years after the date of grant. The fair market value of each option granted was \$4.40 per option.

The fair value was estimated on the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	May 7, 2007
Dividend yield (%)	3.06
Expected volatility (%)	18.9
Risk-free interest rate (%)	4.18
Weighted average expected life (years)	4.5

On August 16, 2007, the Corporation granted 136,832 options on common shares under its 2006 Plan at the five-day volume weighted average trading price immediately preceding the date of grant of \$25.76. These options vest evenly over a four-year period on each anniversary of the date of grant. The options expire seven years after the date of grant. The fair market value of each option granted was \$4.25 per option.

The fair value was estimated on the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

	August 16, 2007
Dividend yield (%)	3.06
Expected volatility (%)	19.6
Risk-free interest rate (%)	4.43
Weighted average expected life (years)	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was \$2 million for the year ended December 31, 2007 (2006 – \$2 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit of their annual retainer to a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of the Common Shares of the Corporation. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective during 2006, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Number of DSUs:	2007	2006
DSUs outstanding, beginning of year	46,959	24,986
Granted	20,859	22,101
Granted – notional dividends reinvested	1,904	1,198
DSUs paid out	–	(1,326)
DSUs outstanding, end of year	69,722	46,959

For the year ended December 31, 2007, expenses of \$0.8 million (2006 – \$0.8 million) were recorded in relation to the DSU Plan.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

15. Stock-Based Compensation Plans (cont'd)

RSU Plan

In 2004, the Corporation introduced the RSU Plan, which is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer ("CEO") of the Corporation. Each RSU represents a unit with an underlying value equivalent to the value of the Common Shares of the Corporation.

Number of RSUs:	2007	2006
RSUs outstanding, beginning of year	66,845	36,855
Granted	19,570	28,400
Granted – notional dividends reinvested	1,883	1,590
RSUs paid out	(20,683)	–
RSUs outstanding, end of year	67,615	66,845

In May 2007, RSUs paid out to the President and CEO were 20,683 at \$28.01 per RSU, for a total of approximately \$0.6 million. The payout was made upon the three-year maturation period in respect of the RSU grant which was made on May 11, 2004, and the President and CEO satisfying the payment criteria.

For the year ended December 31, 2007, expenses of \$0.6 million (2006 – \$0.7 million) were recorded in relation to the RSU Plan.

16. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities, as discussed in Note 2.

	2007			
(in millions)	Opening balance January 1	Transition amount January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities	\$ (51)	\$ –	\$ (31)	\$ (82)
Losses on derivative instruments designated as cash flow hedges, net of tax	–	(1)	–	(1)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	–	(5)	–	(5)
Accumulated other comprehensive loss	\$ (51)	\$ (6)	\$ (31)	\$ (88)

	2006		
(in millions)	Opening balance January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities	\$ (16)	\$ (35)	\$ (51)
Accumulated other comprehensive loss	\$ (16)	\$ (35)	\$ (51)

As required, prior periods have not been restated as a result of implementing Section 1530, *Comprehensive Income*, except to reclassify unrealized foreign currency translation losses on net investments in self-sustaining foreign operations, net of hedging activities, of \$51 million as at January 1, 2007 from the foreign currency translation adjustment account in shareholders' equity to accumulated other comprehensive loss. As required upon initial application of Section 3855, *Financial Instruments – Recognition and Measurement*, all adjustments to the carrying amount of financial instruments were recognized as an adjustment to the opening balance of accumulated other comprehensive loss. The Corporation was not required to remeasure any assets or liabilities upon adoption of Section 3855; therefore, no adjustments were made to the opening balance of retained earnings.

During 2007, unrealized foreign currency translation losses of \$70 million (2006 – gains of \$9 million) were recorded in other comprehensive loss related to the Corporation's net investment in US dollar-denominated self-sustaining foreign operations. These unrealized foreign currency translation losses were partially offset by the effective portion of unrealized after-tax gains of \$39 million (2006 – after-tax losses of \$5 million) related to the translation of US dollar-denominated long-term debt designated as a foreign currency risk hedge. There was no ineffective portion.

On November 7, 2006, the Corporation, through a wholly owned subsidiary, acquired an additional approximate 16 per cent ownership interest in Caribbean Utilities and now holds an approximate 54 per cent controlling interest in the Company. As a result of this acquisition, a foreign currency translation loss of \$39 million was reflected in accumulated other comprehensive loss, representing the impact of the appreciation of the Canadian dollar relative to the US dollar between the original share purchase dates and the recording of the net investment in Caribbean Utilities as a self-sustaining foreign operation, effective November 7, 2006.

During 2007, unrealized losses of an immaterial amount were recorded in other comprehensive loss for the effective portion of the change in fair value of the interest rate swap agreements at Fortis Properties and BECOL designated as cash flow hedges, with the offset recorded to deferred credits on the balance sheet. There were no ineffective portions. The amounts recognized are reclassified to finance charges in the periods during which the variability of cash flows of the hedged items affect finance charges. The net loss reclassified to earnings during 2007 was immaterial. In November 2007, BECOL cancelled its interest rate swap agreement upon the early repayment of the related debt.

As at January 1, 2007, in accordance with the transitional provisions of Section 3865, *Hedges*, a net loss of \$5 million associated with unamortized deferred gain and loss balances related to previously cancelled swap agreements were reclassified to accumulated other comprehensive loss. An unamortized loss balance of \$11 million (\$7 million after-tax), as at January 1, 2007, related to a previously cancelled interest rate swap agreement, was reclassified from deferred charges and other assets (Note 5) and an unamortized gain balance of \$3 million (\$2 million after-tax), as at January 1, 2007, related to a previously cancelled US dollar forward currency swap agreement was reclassified from deferred credits (Note 11). The deferred gain and loss balances are amortized to comprehensive income (loss) on a straight-line basis over the life of the related debt.

17. Finance Charges

(in millions)

	2007	2006
Interest – Long-term debt and capital lease obligations	\$ 266	\$ 155
– Short-term borrowings	27	6
Interest charged to construction (Note 2)	(8)	(4)
Interest earned	(4)	(4)
Unrealized foreign exchange loss (gain) on long-term debt	1	(2)
Dividends on preference shares (Notes 13 (i) and (ii) and 14)	17	17
	\$ 299	\$ 168

Interest on long-term debt, short-term borrowings and dividends associated with preference shares have been calculated using the effective interest rate method, effective January 1, 2007, in accordance with the adoption of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

18. Gain on Sale of Property

In December 2007, TGI sold surplus land resulting in an \$8 million (\$7 million after-tax) gain on sale.

In June 2006, Fortis Properties sold the Days Inn Sydney resulting in a \$2 million (\$1.6 million after-tax) gain on sale.

19. Corporate Taxes

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted Canadian federal and provincial statutory tax rates to earnings before corporate taxes. The following is a reconciliation of the consolidated statutory tax rate to the consolidated effective tax rate:

(%)	2007	2006
Statutory tax rate	35.1	35.2
Preference share dividends	2.4	3.2
Difference between Canadian statutory rates and those applicable to foreign subsidiaries	(7.1)	(6.8)
Items capitalized for accounting but expensed for income tax purposes	(8.3)	(10.7)
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	(4.8)	(1.2)
Impact of reduction in income tax rates on future income taxes	(2.4)	(2.4)
Regulatory deferrals at Newfoundland Power	(1.0)	–
TGI tax reassessment	0.9	–
Maritime Electric tax reassessment	1.0	0.9
Pension costs	(0.7)	(0.4)
Other	(0.7)	(0.9)
Effective tax rate	14.4	16.9

The components of the provision for corporate taxes are as follows:

(in millions)	2007	2006
Canadian		
Current taxes	\$ 33	\$ 20
Future income taxes	–	9
	33	29
Foreign		
Current taxes	3	2
Future income taxes	–	1
	3	3
Corporate tax expense	\$ 36	\$ 32

Future income taxes are provided for temporary differences. Future income tax assets and liabilities are comprised of the following:

<i>(in millions)</i>	2007	2006
Future income tax liability (asset)		
Utility capital assets and income producing properties	\$ 35	\$ 46
ECAM	10	5
Other regulatory assets and liabilities	2	11
Intangible assets	2	3
Tenant inducements	3	2
Employee future benefits	(14)	(9)
Losses carried forward	(10)	(8)
Share issue and debt financing costs	(16)	(1)
Unrealized foreign currency translation gains on long-term debt	8	2
Other	5	1
Net future income tax liability	\$ 25	\$ 52
Current future income tax liability	\$ 7	\$ 1
Long-term future income tax asset	(37)	(7)
Long-term future income tax liability	55	58
Net future income tax liability	\$ 25	\$ 52

As at December 31, 2007, the Corporation had approximately \$49 million (2006 – \$24 million) in non-capital and capital losses carried forward, of which \$0.2 million (2006 – \$0.3 million) in capital losses has not been recognized in the financial statements. The non-capital loss carry forwards expire between 2008 and 2027.

20. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, Terasen, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEB plans for qualifying employees.

For the defined benefit pension arrangements, the accrued benefit obligation and the market-related value or fair value of plan assets are measured for accounting purposes as at December 31st of each year for the Corporation, Terasen and Newfoundland Power; as at September 30th of each year for FortisAlberta, FortisBC and FortisOntario; and as at April 30th of each year for Caribbean Utilities. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2006 for FortisOntario; as of December 31, 2005 for the Corporation and Newfoundland Power; as of December 31, 2004 for FortisAlberta and FortisBC; and as of April 30, 2006 for Caribbean Utilities. For Terasen, the most recent actuarial valuations of the pension plans for funding purposes were between December 31, 2004 and December 31, 2006. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each company and those required as at December 31, 2007 are expected to be completed during 2008.

The Corporation's defined benefit pension plan asset allocation was as follows:

Plan assets as at December 31st

<i>(%)</i>	2007	2006
Canadian equities	50	45
Fixed income	38	39
Foreign equities	8	15
Real estate	4	1
	100	100

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

20. Employee Future Benefits (cont'd)

The following is a breakdown of the Corporation's defined benefit pension plans and their respective funded or unfunded status:

	2007			2006		
	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
<i>(in millions)</i>						
Terasen	\$ 254	\$ 261	\$ 7	\$ –	\$ –	\$ –
FortisAlberta	23	20	(3)	21	18	(3)
FortisBC	122	105	(17)	118	95	(23)
Newfoundland Power	236	260	24	239	250	11
FortisOntario	23	21	(2)	25	21	(4)
Caribbean Utilities	5	3	(2)	6	3	(3)
Fortis Inc.	4	4	–	4	3	(1)
Total	\$ 667	\$ 674	\$ 7	\$ 413	\$ 390	\$ (23)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
	2007	2006	2007	2006	2007	2006
<i>(in millions)</i>						
Change in accrued benefit obligation						
Balance, beginning of year	\$ 413	\$ 390	\$ 17	\$ 14	\$ 109	\$ 103
Liability associated with acquisitions	248	6	27	–	79	–
Current service costs	12	7	1	1	4	3
Employee contributions	6	3	–	–	–	–
Interest costs	29	20	2	1	8	5
Benefits paid	(25)	(19)	(2)	–	(4)	(4)
Actuarial (gain) loss	(16)	2	(1)	–	(8)	2
Plan amendments	–	4	–	1	1	–
Balance, end of year	\$ 667	\$ 413	\$ 44	\$ 17	\$ 189	\$ 109
Change in value of plan assets						
Balance, beginning of year	\$ 390	\$ 350	\$ –	\$ –	\$ –	\$ –
Assets associated with acquisitions	256	3	–	–	–	–
Actual return on plan assets	26	35	–	–	–	–
Benefits paid	(25)	(19)	(2)	–	(4)	(4)
Employee contributions	6	3	–	–	–	–
Employer contributions	21	18	2	–	4	4
Balance, end of year	\$ 674	\$ 390	\$ –	\$ –	\$ –	\$ –
Funded status						
Surplus (deficit), end of year	\$ 7	\$ (23)	\$ (44)	\$ (17)	\$ (189)	\$ (109)
Unamortized net actuarial loss	95	85	3	3	61	39
Unamortized past service costs	10	9	1	1	(2)	–
Unamortized transitional obligation	7	21	2	1	18	19
Employer contributions after measurement date	1	1	–	–	–	–
Accrued benefit asset (liability), end of year (Notes 5 and 11)	\$ 120	\$ 93	\$ (38)	\$ (12)	\$ (112)	\$ (51)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	2007	2006	2007	2006	2007	2006
Significant assumptions						
Discount rate during year (%)	5.00–5.25	5.00–5.25	5.00–5.25	5.00–5.25	5.00–5.25	5.00–5.25
Discount rate as at December 31 st (%)	5.25–5.60	5.00–5.25	5.25–5.75	5.25	5.25–5.75	5.00–5.25
Expected long-term rate of return on plan assets (%)	6.50–7.50	6.50–7.50	–	–	–	–
Rate of compensation increase (%)	3.50–4.25	3.50–4.00	3.77–4.25	3.50–4.00	3.50–4.25	3.50–4.00
Health care cost trend increase as at December 31 st (%)	–	–	–	–	4.50–10.00	4.50–10.00
Expected average remaining service life of active employees (years)	7–13	7–15	3–13	3–15	10–16	11–17
Components of net benefit expense						
Current service costs	\$ 12	\$ 7	\$ 1	\$ 1	\$ 4	\$ 3
Interest costs	29	20	2	1	8	5
Actual return on plan assets	(26)	(35)	–	–	–	–
Actuarial (gain) loss	(16)	2	(1)	–	(8)	2
Plan amendments	–	–	–	–	1	–
Costs arising in the year	(1)	(6)	2	2	5	10
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	(11)	11	–	–	–	–
Actuarial gain	20	4	1	–	11	–
Past service costs	3	2	–	1	–	–
Special termination benefits	1	–	–	–	–	–
Transitional obligation and amendments	1	2	–	–	2	2
Regulatory adjustment	(1)	(2)	–	(1)	(7)	(5)
Net benefit expense	\$ 12	\$ 11	\$ 3	\$ 2	\$ 11	\$ 7

For 2007, the effects of changing the health-care cost trend rate by a 1 per cent increase and a 1 per cent decrease are as follows:

(in millions)	1 per cent increase in rate	1 per cent decrease in rate
Increase (decrease) in accrued benefit obligation	\$ 28	\$ (23)
Increase (decrease) in service and interest costs	\$ 2	\$ (2)

During 2007, the Corporation expensed \$10 million (2006 – \$8 million) related to defined contribution pension plans.

21. Business Acquisitions

2007

a. Terasen

On May 17, 2007, Fortis acquired all of the issued and outstanding common shares of Terasen for aggregate consideration of approximately \$3.7 billion. The net cash purchase price of approximately \$1.25 billion, including acquisition costs, was primarily financed through proceeds from the issuance of common equity, with the remaining \$125 million of the cash purchase price being financed, on an interim basis, through drawings on the Corporation's committed credit facility.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

21. Business Acquisitions (cont'd)

2007 (cont'd)

a. Terasen (cont'd)

Terasen owns and operates a gas distribution business carried on by TGI, TGVI and TGWI, collectively referred to as the Terasen Gas companies. Terasen is the principal natural gas distributor in British Columbia, serving over 918,000 customers or 96 per cent of gas users in the province.

The acquisition has been accounted for using the purchase method, whereby the consolidated results of Terasen have been included in the consolidated financial statements of Fortis commencing May 17, 2007. The financial results of the Terasen Gas companies have been included in the Regulated Gas Utilities – Canadian segment, while net expenses of non-regulated Terasen corporate-related activities, and Terasen's 30 per cent investment in non-regulated CWLP have been included in the Corporate and Other segment. The Terasen Gas companies are regulated under traditional cost of service. The determination of revenue and earnings is based on regulated rates of return that are applied to historic values which do not change with a change of ownership. Therefore, for substantially all of the individual assets and liabilities associated with the Terasen Gas companies, no fair market value adjustments were recorded as part of the purchase price because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, the book value of substantially all of the assets and liabilities of the Terasen Gas companies has been assigned as fair value for the purchase price allocation. Substantially all of the fair market value adjustments, including intangibles, recorded as part of the purchase price allocation related to non-regulated Terasen and its non-regulated investments.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition. The allocation of the purchase price is subject to finalization, with adjustments, if any, to be completed during the second quarter of 2008. The amount of the purchase price assignable to goodwill is entirely associated with the regulated Terasen Gas companies. Approximately \$40 million of goodwill is deductible for tax purposes. Of the \$11 million in intangible assets, \$10 million was assigned as the value associated with customer contracts at CWLP. Approximately \$1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

<i>(in millions)</i>	Total
Fair value assigned to net assets:	
Utility capital assets	\$ 2,768
Current assets	355
Goodwill	907
Intangibles	11
Long-term regulatory assets	69
Other assets	42
Current liabilities	(353)
Assumed short-term indebtedness	(275)
Assumed long-term debt (including current portion)	(2,077)
Long-term regulatory liabilities	(29)
Other liabilities	(165)
	1,253
Cash	3
	\$ 1,256

b. Delta Regina

On August 1, 2007, Fortis Properties purchased the Delta Regina, comprising the Delta Regina Hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan for an aggregate cash purchase price of approximately \$50 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing August 1, 2007.

The purchase price allocation to assets, based on their fair values, was as follows:

(in millions)

	Total
Fair value assigned to net assets:	
Income producing properties	\$ 50

2006

a. Caribbean Utilities

On November 7, 2006, Fortis, through a wholly owned subsidiary, acquired an aggregate of 4,113,116 of the outstanding Class A Ordinary Shares of Caribbean Utilities for US\$11.89 per share under a private agreement with International Power Holdings Ltd. ("IPHL") and four other vendors affiliated with IPHL. The aggregate purchase price of \$56 million (US\$49 million), including acquisition costs, was financed through cash consideration from the issuance of US\$40 million unsecured subordinated convertible debentures, combined with drawings on the Corporation's credit facilities.

Following this acquisition, Fortis controls Caribbean Utilities by beneficially owning 13,565,511, or approximately 54 per cent, of the outstanding Class A Ordinary Shares of Caribbean Utilities.

The acquisition has been accounted for using the purchase method. Caribbean Utilities' balance sheet as at November 7, 2006 was consolidated in the December 31, 2006 balance sheet of Fortis. Beginning with the first quarter of 2007, Fortis has been consolidating Caribbean Utilities' financial statements on a two-month lag basis and, accordingly, has consolidated Caribbean Utilities' October 31, 2007 balance sheet, and statements of earnings and cash flows for the 12-month period ended October 31, 2007 with the Corporation's December 31, 2007 Consolidated Financial Statements. During 2006, the statement of earnings of Fortis reflected the Corporation's previous approximate 37 per cent ownership interest in Caribbean Utilities, accounted for on an equity basis, on a two-month lag. Caribbean Utilities' financial results are reported in the Corporation's Regulated Electric Utilities – Caribbean segment.

The determination of revenues and earnings of Caribbean Utilities is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, no fair market value adjustments were recorded as part of the purchase price on those net assets included in the defined asset base upon which the Company is permitted to earn a regulated rate of return, as all economic benefits associated with them beyond the regulated rate of return will accrue to customers. The book value of the net assets included in the defined asset base has been assigned as fair value for purchase price allocation. The book value of net assets not included in the defined asset base approximates fair value. Therefore, no fair market value adjustments have been recorded as part of the purchase price associated with these items.

The Corporation has accounted for the acquisition of the controlling interest in Caribbean Utilities as a two-step acquisition for the purpose of purchase price allocation and the assigning of costs to identifiable assets, goodwill and intangible assets, if any.

The total purchase price allocation was as follows:

(in millions)

Fair value assigned to net assets:	
Utility capital assets	\$ 318
Current assets	30
Goodwill	106
Regulatory assets	13
Other assets	2
Current liabilities	(29)
Assumed long-term debt (including current portion)	(178)
Non-controlling interest	(77)
	185
Cash	3
	<u>\$ 188</u>

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

21. Business Acquisitions (cont'd)

2006 (cont'd)

b. Fortis Turks and Caicos

On August 28, 2006, Fortis, through a wholly owned subsidiary, acquired all of the issued and outstanding common shares of PPC and Atlantic (collectively referred to as Fortis Turks and Caicos) for aggregate consideration of approximately \$98 million (US\$88 million). The purchase price, net of assumed debt and acquisition costs, of \$76 million (US\$68 million) was initially financed, through cash consideration, by way of drawings on the Corporation's credit facilities that were repaid, in part, with partial proceeds from the issuance of First Preference Shares, Series F of Fortis on September 28, 2006.

The acquisition has been accounted for using the purchase method, whereby the results of operations of Fortis Turks and Caicos have been included in the consolidated financial statements of Fortis in the Regulated Electric Utilities – Caribbean segment, commencing August 28, 2006. The determination of revenues and earnings of Fortis Turks and Caicos is based on a regulated rate of return that is applied to historic values which do not change with a change of ownership. Therefore, no fair market value adjustments were recorded as part of the purchase price on those net assets included in the defined asset base upon which the Company is permitted to earn a regulated rate of return, as all economic benefits associated with them beyond the regulated rate of return will accrue to customers. The book value of the net assets included in the defined asset base has been assigned as fair value for purchase price allocation. The book value of net assets not included in the defined asset base approximates fair value. Therefore, no fair market value adjustments have been recorded as part of the purchase price associated with these items.

The purchase price allocation was as follows:

<i>(in millions)</i>	PPC	Atlantic	Total
Fair value assigned to net assets:			
Utility capital assets	\$ 45	\$ 1	\$ 46
Current assets	18	1	19
Goodwill	39	–	39
Other assets	1	–	1
Current liabilities	(3)	–	(3)
Assumed long-term debt (including current portion)	(22)	–	(22)
Other liabilities	(2)	(2)	(4)
	<u>\$ 76</u>	<u>\$ –</u>	<u>\$ 76</u>

c. Hotels

On November 1, 2006, Fortis Properties purchased assets comprising four hotels in Alberta and British Columbia for an aggregate cash purchase price of approximately \$52 million, including assumed debt and acquisition costs. The four hotels were the Holiday Inn Express and Suites, and Best Western, in Medicine Hat, Alberta; Ramada Hotel and Suites in Lethbridge, Alberta; and Holiday Inn Express in Kelowna, British Columbia.

The acquisition has been accounted for using the purchase method, whereby the results of operations of the hotels have been included in the consolidated financial statements of Fortis from the date of acquisition, commencing November 1, 2006.

The purchase price allocation to net assets, based on their fair values, was as follows:

<i>(in millions)</i>	
Fair value assigned to net assets:	
Income producing properties	\$ 52
Assumed long-term debt (including current portion)	(12)
	<u>\$ 40</u>

22. Segmented Information

Information by reportable segment is as follows:

Year ended December 31, 2007 (in millions)	REGULATED							NON-REGULATED				
	Gas Utilities	Electric Utilities										
	Terasen Gas Companies – Canadian ⁽¹⁾	Fortis Alberta	Fortis BC	NF Power	Other Canadian ⁽²⁾	Total Electric Canadian	Electric Caribbean ⁽³⁾	Fortis Generation	Fortis Properties	Corporate and Other	Inter- segment eliminations	Consolidated
Operating revenues	905	270	229	490	263	1,252	307	75	191	22	(34)	2,718
Energy supply costs	559	–	67	327	174	568	169	8	–	–	(17)	1,287
Operating expenses	150	122	69	53	29	273	49	14	123	13	(5)	617
Amortization	58	75	31	34	17	157	28	10	14	6	–	273
Operating income	138	73	62	76	43	254	61	43	54	3	(12)	541
Finance charges	80	36	26	33	17	112	15	10	24	70	(12)	299
Gain on sale of property	(8)	–	–	–	–	–	–	–	–	–	–	(8)
Corporate taxes (recovery)	16	(11)	5	12	10	16	2	8	6	(12)	–	36
Non-controlling interest	–	–	–	1	–	1	13	1	–	–	–	15
Net earnings (loss)	50	48	31	30	16	125	31	24	24	(55)	–	199
Preference share dividends	–	–	–	–	–	–	–	–	–	6	–	6
Net earnings (loss) applicable to common shares	50	48	31	30	16	125	31	24	24	(61)	–	193
Goodwill	907	227	221	–	63	511	126	–	–	–	–	1,544
Identifiable assets	3,540	1,294	914	986	484	3,678	652	235	535	108	(19)	8,729
Total assets	4,447	1,521	1,135	986	547	4,189	778	235	535	108	(19)	10,273
Gross capital expenditures	120	285	147	72	38	542	106	17	13	5	–	803
Year ended December 31, 2006												
Operating revenues	–	251	216	421	252	1,140	101	80	163	9	(31)	1,462
Equity income	–	–	–	–	–	–	10	–	–	–	–	10
Energy supply costs	–	–	68	256	171	495	57	6	–	–	(18)	540
Operating expenses	–	115	63	54	28	260	13	15	105	11	(5)	399
Amortization	–	69	28	33	15	145	7	11	12	3	–	178
Operating income	–	67	57	78	38	240	34	48	46	(5)	(8)	355
Finance charges	–	30	23	33	15	101	5	10	21	39	(8)	168
Gain on sale of property	–	–	–	–	–	–	–	–	(2)	–	–	(2)
Corporate taxes (recovery)	–	(5)	7	14	9	25	2	8	8	(11)	–	32
Non-controlling interest	–	–	–	1	–	1	4	3	–	–	–	8
Net earnings (loss)	–	42	27	30	14	113	23	27	19	(33)	–	149
Preference share dividends	–	–	–	–	–	–	–	–	–	2	–	2
Net earnings (loss) applicable to common shares	–	42	27	30	14	113	23	27	19	(35)	–	147
Goodwill	–	228	221	–	63	512	149	–	–	–	–	661
Identifiable assets	–	1,158	810	929	447	3,344	679	246	486	43	(18)	4,780
Total assets	–	1,386	1,031	929	510	3,856	828	246	486	43	(18)	5,441
Gross capital expenditures	–	243	111	60	37	451	27	3	17	2	–	500

⁽¹⁾ Terasen was acquired on May 17, 2007.

⁽²⁾ Includes Maritime Electric and FortisOntario

⁽³⁾ Includes Belize Electricity, Fortis Turks and Caicos, acquired on August 28, 2006, and Caribbean Utilities on Grand Cayman, Cayman Islands

The Corporation has changed the reporting of its operating segments whereby the financial results of Maritime Electric and FortisOntario have now been aggregated into one reportable segment and presented as "Regulated Electric Utilities – Other Canadian". Comparative segmented information has been restated to reflect this change in reporting.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

22. Segmented Information (cont'd)

During 2007, the Corporation began reporting a new segment "Regulated Gas Utilities – Canadian" which includes the financial results of the regulated gas distribution business of Terasen, the principal natural gas distributor in British Columbia, acquired by the Corporation on May 17, 2007. Additionally, net expenses of non-regulated Terasen corporate-related activities, and Terasen's 30 per cent ownership interest in CWLP, have been included in the Corporate and Other segment from May 17, 2007.

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the years ended December 31st were as follows:

(in millions)	2007	2006
Sales from Fortis Generation to Belize Electricity	\$ 15	\$ 17
Sales from Fortis Generation to FortisOntario	1	1
Sales from Newfoundland Power to Fortis Properties	4	3
Inter-segment finance charges on borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	2	2
Corporate to Fortis Properties	8	5
Fortis Generation to Belize Electricity	–	1

23. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	2007	2006
Interest paid	\$ 288	\$ 161
Income taxes paid	\$ 53	\$ 54

24. Financial Instruments

Fair Values

The Corporation has designated its financial instruments as follows:

(in millions)	December 31, 2007		December 31, 2006	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents ⁽¹⁾	\$ 58	\$ 58	\$ 41	\$ 41
Loans and receivables				
Accounts receivable ⁽¹⁾⁽²⁾	635	635	286	286
Other receivables due from customers ⁽¹⁾⁽²⁾⁽³⁾	7	7	6	6
Other financial liabilities				
Short-term borrowings ⁽¹⁾⁽²⁾	475	475	98	98
Accounts payable and accrued charges ⁽¹⁾⁽²⁾	793	793	333	333
Dividends payable ⁽¹⁾⁽²⁾	43	43	22	22
Customer deposits ⁽¹⁾⁽²⁾⁽⁴⁾	5	5	5	5
Long-term debt, including current portion ⁽⁵⁾⁽⁶⁾	5,023	5,635	2,614	2,940
Preference shares, classified as debt ⁽⁵⁾⁽⁷⁾	320	346	320	355

⁽¹⁾ Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

⁽²⁾ Carrying value approximates amortized cost

⁽³⁾ Included in deferred charges and other assets on the balance sheet

⁽⁴⁾ Included in deferred credits on the balance sheet

⁽⁵⁾ Carrying value is measured at amortized cost using the effective interest rate method.

⁽⁶⁾ Carrying value at December 31, 2007 is net of unamortized deferred financing costs of \$33 million. On January 1, 2007, deferred financing costs were reclassified from deferred charges and other assets in accordance with the transitional provisions of Section 3855.

⁽⁷⁾ Preference shares classified as equity are excluded from the requirements of Section 3855; however, the estimated fair value of the Corporation's \$122 million of preference shares classified as equity as at December 31, 2007 was \$107 million (December 31, 2006 – \$129 million).

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by discounting the future cash flow of each debt instrument at the estimated yield to maturity for the same or similar issues at the balance sheet date, or by using available quoted market prices. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

Risk Management

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table indicates the valuation of derivative financial instruments as at December 31st.

Liability	2007 ⁽¹⁾				2006	
	Term to Maturity (years)	Number of Swaps	Carrying Value (in millions)	Estimated Fair Value (in millions)	Carrying Value (in millions)	Estimated Fair Value (in millions)
Interest Rate Swaps	1 to 3	4	\$ –	\$ –	\$ –	\$ (1)
Natural Gas Commodity Swaps and Options	Up to 3	244	\$ (79)	\$ (79)	\$ –	\$ –

⁽¹⁾ Includes derivative financial instruments of the Terasen Gas companies from May 17, 2007, the date of acquisition

Fortis Properties has designated its interest rate swap agreements as hedges of the cash flow risk related to floating-rate long-term debt. As at January 1, 2007, in accordance with the transitional provisions of Section 3865, the fair value of the interest rate swap agreements of \$(1) million was recorded as a derivative financial instrument and grouped with deferred credits on the balance sheet with the offset reflected in accumulated other comprehensive loss (Note 16). The Terasen Gas companies have designated their interest rate swap agreements as hedges of cash flow risk related to floating-rate debt instruments. Any changes in the fair value of these interest rate swaps, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. The interest rate swaps are valued at the present value of future cash flows based on published forward future interest rate curves.

The majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices and natural gas commodity swaps and options are used, therefore, to fix the effective purchase price of natural gas. As at December 31, 2007, none of the natural gas commodity swaps and options were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas commodity swaps and options, whether or not in a qualifying hedging relationship, are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates. The fair values of the natural gas commodity swaps and options reflect the estimated amounts that the Terasen Gas companies would pay to terminate the contracts as at December 31, 2007, and were recorded in accounts payable as at December 31, 2007.

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate based on relevant market information about the instruments. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

The Corporation has exposure to foreign currency exchange rate fluctuations associated with its US dollar-denominated operations. The Corporation may periodically enter into hedges of its foreign currency exposures on its foreign net investments by entering into offsetting forward exchange contracts and through the use of US dollar borrowings.

The Corporation's foreign net investments are exposed to changes in US dollar exchange rates. The Corporation has effectively decreased its exposure to foreign currency exchange rate fluctuations associated with its foreign net investments through the use of US dollar borrowings. As at December 31, 2007, all of the Corporation's US\$392 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's US dollar borrowings designated as hedges are recorded in the statement of comprehensive income (loss). As at December 31, 2007, the Corporation had approximately US\$50 million in foreign net investments available to be hedged.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

24. Financial Instruments (cont'd)

Interest Rate Risk

Long-term debt is primarily issued at fixed interest rates, thereby minimizing cash flow and interest rate exposure. The Corporation is subject to risks associated with fluctuating interest rates primarily on its short-term and variable-rate credit-facility borrowings. The Corporation designates its interest rate swap contracts as hedges of the underlying debt. Interest expense on the debt is adjusted to include payments made or received under the interest rate swaps.

The Terasen Gas companies use a BCUC-approved interest rate deferral account to absorb interest rate fluctuations, thereby effectively fixing the rate of interest on short-term and variable-rate credit-facility borrowings.

Credit Risk

The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments and credit risk on physical off-system sales. Non-performance by the counterparties is not anticipated since these counterparties are high credit quality financial institutions. In addition, the Corporation is exposed to credit risk from customers. However, the Corporation generally has a large and diversified customer base, which minimizes the concentration of this risk. FortisAlberta, however, is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

Rate Regulation

Certain of the Corporation's regulated utilities have rate stabilization accounts, which are approved by the regulators, to recover excess gas and energy costs over an established benchmark. These accounts minimize the impact of changing gas and energy costs on the financial results of the Corporation.

25. Commitments

(in millions)	Total	< 1 year	1–3 years	4–5 years	> 5 years
Gas purchase contract obligations ⁽¹⁾	\$ 537	\$ 515	\$ 22	\$ –	\$ –
Power purchase obligations					
FortisBC ⁽²⁾	2,856	40	74	76	2,666
FortisOntario ⁽³⁾	286	21	43	45	177
Maritime Electric ⁽⁴⁾	7	7	–	–	–
Belize Electricity ⁽⁵⁾	15	2	2	2	9
Capital cost ⁽⁶⁾	402	14	34	39	315
Joint-use asset and shared service agreements ⁽⁷⁾	66	4	8	6	48
Office lease – FortisBC ⁽⁸⁾	20	1	2	2	15
Operating lease obligations ⁽⁹⁾	176	20	33	30	93
Other	25	6	10	9	–
Total	\$ 4,390	\$ 630	\$ 228	\$ 209	\$ 3,323

⁽¹⁾ Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2007.

⁽²⁾ Power purchase obligations of FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the Power Purchase Agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The Power Purchase Agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW, but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

- 
- (3) Power purchase obligations for FortisOntario primarily include a long-term take-or-pay contract between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The contract, which expires on December 31, 2019, provides approximately one-third of Cornwall Electric's load. Cornwall Electric also has a two-year contract in place with Hydro-Québec Energy Marketing, which expires on June 30, 2008. This take-or-pay contract provides energy on an as-needed basis but charges for 100 MW of capacity at \$0.14 million per month.
- (4) Maritime Electric has one take-or-pay contract with New Brunswick Power ("NB Power") for the purchase of either capacity or energy. This contract totals approximately \$7 million through March 31, 2008.
- (5) Power purchase obligations for Belize Electricity include a 15-year power purchase agreement between Belize Electricity and Hydro Maya Limited, which commenced in February 2007, for the supply of 3 MW of capacity and a two-year power purchase agreement between Belize Electricity and Comisión Federal de Electricidad of Mexico, expiring in August 2008, for the supply of 15 MW of firm energy. Belize Electricity has also signed a 15-year power purchase agreement with Belize Cogeneration Energy Limited ("Belcogen"), which is scheduled to commence in mid-2009, that provides for the supply of approximately 14 MW of capacity. Belcogen has not yet commenced construction of the related bagasse-fired electric generating facility; therefore, the obligation related to the power purchase agreement with Belcogen has not been included in the Corporation's contractual obligations.
- (6) Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.
- (7) FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2012 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.
- (8) Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term (Note 4 (xii)).
- (9) Operating lease obligations include certain office, warehouse, natural gas transmission and distribution asset, vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro Inc.

The regulated subsidiaries of the Corporation are obligated to provide service to customers within their respective service territories. These regulated subsidiaries' capital expenditures are largely driven by customer requests or include large capital projects specifically approved by their respective regulators. The consolidated capital program of the Corporation, including non-regulated segments, is forecast to include approximately \$901 million in capital expenditures for 2008. This commitment has not been included in the commitments table above.

In prior years, TGVl received non-interest bearing repayable loans from the federal and provincial governments of \$50 million and \$25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVl to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVl's approved capital structure, as will TGVl's rate base, which is used in determining customer rates. The repayment criteria were met in 2007 and TGVl is expected to make an approximate \$6 million repayment on the loans in 2008. As at December 31, 2007, the outstanding balance of the repayable government loans was \$67 million with approximately \$6 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the commitments table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVl's RDDA and the ability of TGVl to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

Notes to Consolidated Financial Statements

December 31, 2007 and 2006

26. Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims that arise in the ordinary course of business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately \$37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister has reduced the assessment to \$7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. On June 22, 2007, TGI filed an appeal of the assessment with the B.C. Supreme Court (Note 4 (x)).

A non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the Consolidated Financial Statements. Terasen has begun the appeal process associated with the assessments.

FortisAlberta

On March 24, 2006, Her Majesty the Queen in Right of Alberta (the "Crown") filed a statement of claim in the Court of Queen's Bench of Alberta in the Judicial District of Edmonton against FortisAlberta. The Crown's claim is that the Company is responsible for a fire that occurred in October 2003 in an area of the Province of Alberta commonly referred to as Poll Haven Community Pasture. The Crown is seeking approximately \$3 million in firefighting and suppression costs and approximately \$2 million in timber losses, as well as interest and other costs. FortisAlberta and the Crown have exchanged several investigation and expert reports. Both the factual evidence and expert opinion received to date leads management to believe that FortisAlberta is not responsible for the cause of the fire and has no liability for the damages. However, FortisAlberta has not made any definitive assessment of potential liability, and the outcome with regard to the Company's liability for the claims made by the Crown is indeterminable. No amount, therefore, has been accrued in the Consolidated Financial Statements.

FortisBC

The B.C. Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with two filed writs and statements of claim by private landowners in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the Consolidated Financial Statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately \$6 million on January 2, 2001 associated with a settlement with NB Power regarding its \$450 million write-down of the Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and filed a Notice of Objection with the Chief of Appeals at CRA. Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately \$13 million in taxes and accrued interest. As at December 31, 2007, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately \$6 million.



FortisUS Energy

Legal proceedings were initiated against FortisUS Energy by the Village of Philadelphia (the “Village”), New York. The Village claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately \$7 million (US\$7 million). The First American Title Insurance Company is defending the action on behalf of FortisUS Energy. A Memorandum Decision and Order was filed by the State of New York Supreme Court of Jefferson County on December 21, 2006 granting summary judgment to FortisUS Energy dismissing the action by the Village. An appeal of the summary judgment dismissal of the claim filed by the Village in January 2007 was heard by the Appellate Division, Fourth Judicial Department of the Supreme Court of the State of New York in December 2007. The Appellate Division delivered its Memorandum and Order on February 1, 2008 modifying the initial decision by dismissing the Village’s appeal regarding its main claim, but reinstating a secondary cause of action dismissed by the summary judgment order. Further appeals to the New York State Court of Appeal may be forthcoming. Management believes that potential further legal actions by the Village will not be successful and, therefore, no provision has been made in the Consolidated Financial Statements.

27. Subsequent Event

On February 15, 2008, TGV closed a \$250 million 6.05% unsecured debenture offering, maturing on February 15, 2038. The net proceeds of the debenture offering were used to repay existing credit-facility borrowings.

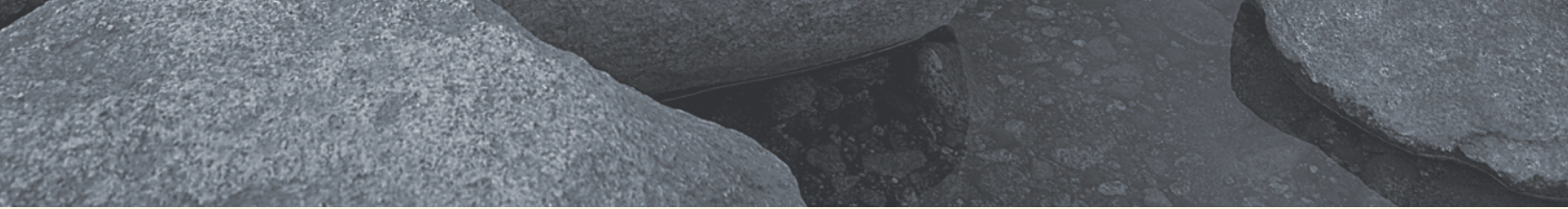
28. Comparative Figures

Certain comparative figures have been reclassified to comply with the current year’s classifications.

Historical Financial Summary

Statements of Earnings (in \$ millions)	2007	2006⁽¹⁾	2005⁽¹⁾	2004
Revenue, including equity income	2,718	1,472	1,441	1,146
Energy supply costs and operating expenses	1,904	939	926	766
Amortization	273	178	158	114
Finance charges	299	168	154	122
Corporate taxes	36	32	70	47
Results of discontinued operations, gains on sales and other unusual items	8	2	10	–
Non-controlling interest	15	8	6	6
Preference share dividends	6	2	–	–
Net earnings applicable to common shares	193	147	137	91
Balance Sheets (in \$ millions)				
Current assets	1,064	405	299	293
Goodwill	1,544	661	512	514
Other long-term assets	424	331	471	418
Utility capital assets and income producing properties	7,241	4,044	3,315	2,713
Total assets	10,273	5,441	4,597	3,938
Current liabilities	1,804	558	412	538
Deposits due beyond one year	–	–	–	–
Deferred credits, regulatory liabilities and future income taxes	688	477	477	138
Long-term debt and capital lease obligations (excluding current portion)	4,623	2,558	2,136	1,905
Non-controlling interest	115	130	39	37
Preference shares (classified as debt)	320	320	320	320
Shareholders' equity	2,723	1,398	1,213	1,000
Cash Flows (in \$ millions)				
Operating activities	373	263	304	272
Financing activities	1,826	456	224	777
Investing activities	2,033	634	467	1,026
Dividends, excluding dividends on preference shares classified as debt	146	77	64	51
Financial Statistics				
Return on average common shareholders' equity (%)	9.99	11.87	12.40	11.28
Capitalization Ratios (%) (year end)				
Total debt and capital lease obligations (net of cash)	64.3	61.1	58.7	61.4
Preference shares (classified as debt and equity)	5.2	10.0	8.6	9.4
Common shareholders' equity	30.5	28.9	32.7	29.2
Interest Coverage (x)				
Debt	1.9	2.2	2.5	2.3
All fixed charges	1.7	2.0	2.1	2.0
Total capital expenditures (in \$ millions)	803	500	446	279
Common share data				
Book value per share (year end) (\$)	16.69	12.19	11.74	10.45
Average common shares outstanding (in millions)	137.6	103.6	101.8	84.7
Basic earnings per common share (\$)	1.40	1.42	1.35	1.07
Dividends declared per common share (\$)	0.880	0.700	0.605	0.548
Dividends paid per common share (\$)	0.820	0.670	0.588	0.540
Dividend payout ratio (%)	58.6	47.2	43.7	50.3
Price earnings ratio (x)	20.7	21.0	18.0	16.2
Share trading summary				
High price (\$) (TSX)	30.00	30.00	25.64	17.75
Low price (\$) (TSX)	24.50	20.36	17.00	14.23
Close price (\$) (TSX)	28.99	29.77	24.27	17.38
Volume (in thousands)	100,920	60,094	37,706	29,254

⁽¹⁾ As at December 31, 2006, the regulatory provision for future site removal and restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated. The effect of this change in presentation at December 31, 2006 was a \$306.5 million (December 31, 2005 – \$280.9 million) increase in long-term regulatory liabilities and a \$306.5 million (December 31, 2005 – \$280.9 million) increase in net utility capital assets.



2003	2002	2001	2000	1999	1998	1997
843	715	628	580	505	473	487
579	477	418	418	356	340	341
62	65	62	52	45	42	41
86	74	65	56	46	44	45
38	32	29	17	28	23	29
–	–	4	3	–	4	–
4	4	4	3	1	1	1
–	–	–	–	–	–	–
74	63	54	37	29	27	30
191	180	135	166	93	94	79
65	60	33	36	39	42	45
345	241	172	163	122	121	115
1,563	1,459	1,246	1,056	930	750	747
2,164	1,940	1,586	1,421	1,184	1,007	986
296	334	272	225	230	148	172
–	–	–	–	16	16	20
62	39	32	24	27	22	23
1,031	941	746	678	488	424	386
37	40	36	32	29	8	8
123	–	50	50	50	50	50
615	586	450	412	344	339	327
157	134	94	97	85	69	63
232	261	171	178	67	16	17
308	349	240	241	122	66	54
38	35	30	28	24	24	23
12.30	12.23	12.44	9.73	8.55	8.24	9.43
60.0	65.2	63.9	60.4	59.6	53.4	53.6
6.7	–	3.6	4.3	5.1	6.0	6.2
33.3	34.8	32.5	35.3	35.3	40.6	40.2
2.2	2.3	2.3	2.1	2.3	2.2	2.6
2.1	2.2	2.2	1.9	2.1	2.0	2.0
208	229	149	158	86	65	50
8.82	8.50	7.50	6.97	6.55	6.52	6.40
69.3	65.1	59.5	54.1	52.2	51.5	50.4
1.06	0.97	0.90	0.68	0.56	0.53	0.60
0.525	0.498	0.470	0.460	0.455	0.450	0.443
0.520	0.485	0.468	0.460	0.453	0.450	0.440
48.9	49.9	51.9	67.6	80.8	84.9	73.9
13.9	13.5	13.0	13.2	14.0	18.0	17.6
15.24	13.28	11.89	9.19	9.93	12.03	10.63
11.63	10.76	8.56	6.88	7.29	8.75	7.83
14.73	13.13	11.74	9.00	7.85	9.56	10.50
31,180	21,676	21,460	26,760	9,024	12,356	13,520

Board of Directors



Board of Directors (back row l-r): David G. Norris, Peter E. Case, Harry McWatters, Michael A. Pavey, Frank J. Crothers, Linda L. Inkpen, Roy P. Rideout, (front row l-r): John S. McCallum, H. Stanley Marshall, Bruce Chafe, Geoffrey F. Hyland

Bruce Chafe *** Chair, Fortis Inc., St. John's, NL

Mr. Chafe, 71, joined the Fortis Inc. Board in May 1997 and was appointed Chair of the Board in May 2006. He is past Chair of the Audit Committee of the Board. Mr. Chafe retired as a senior partner of Deloitte & Touche LLP after a 36-year career providing audit and corporate advisory services. He has been a Director of Fortis Properties Corporation since 1997. Mr. Chafe has served as Chair of Newfoundland Power Inc. and also as a Director of FortisBC Inc. He is a Director of several private investment firms. Mr. Chafe will be retiring from the Board at the Annual Meeting on May 6, 2008.

Peter E. Case * Corporate Director, Freelon, ON

Mr. Case, 53, joined the Fortis Inc. Board in May 2005. After 17 years as a utility and pipeline analyst, he retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. Prior to that position, he was Managing Director at BMO Nesbitt Burns. Mr. Case has been a Director of FortisOntario Inc. since March 2003.

Frank J. Crothers Chairman & CEO, Island Corporate Holdings, Nassau, BS

Mr. Crothers, 63, joined the Fortis Inc. Board in May 2007. Over the past 35 years, Mr. Crothers has served on many public and private sector boards. He served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the former President of P.P.C. Limited, which was acquired by Fortis Inc. in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities Company, Limited. Mr. Crothers also serves as a Director of Abaco Markets, Templeton Investments, Nunisco Resources Limited, Talon Corporation, Fidelity Merchant Bank & Trust Limited, C.A. Bancorp Inc. and Victory Nickel Inc.

Geoffrey F. Hyland * Corporate Director, Caledon, ON

Mr. Hyland, 63, joined the Fortis Inc. Board in May 2001. He retired as President and CEO of ShawCor Ltd. in June 2005. Mr. Hyland is a Director of FortisOntario Inc. He continues to serve on the Board of ShawCor Ltd. and is a Director of Enerflex Systems Income Fund, SCITI Total Return Trust and Exco Technologies Limited.

Linda L. Inkpen * Medical Practitioner, St. John's, NL

Dr. Inkpen, 60, joined the Fortis Inc. Board in April 1994. She has been a medical practitioner since 1975 and is Chair of the Medical Advisory Committee for the St. John's Hospitals for Eastern Health. Dr. Inkpen is a past President of the College of the North Atlantic. She also served on the Royal Commission on Employment and Unemployment. Dr. Inkpen was appointed Chair of the Board of Fortis Properties Corporation in 2000 and is a past Chair of Newfoundland Power Inc.

H. Stanley Marshall President and CEO, Fortis Inc., St. John's, NL

Mr. Marshall, 57, has served on the Fortis Inc. Board since October 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties Corporation. He is also a Director of Toromont Industries Ltd.

John S. McCallum ** Professor of Finance, University of Manitoba, Winnipeg, MB

Mr. McCallum, 64, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

Harry McWatters * President, Sumac Ridge Estate Wine Group, Summerland, BC

Mr. McWatters, 62, joined the Fortis Inc. Board in May 2007. He is the founder of Sumac Ridge Estate Wine Group. Mr. McWatters is President of Black Sage Vineyards Ltd., Hawthorne Mountain Vineyards Limited and Okanagan Estate Wine Cellars Ltd. and is responsible for government and industry relations in western Canada for Vincor Canada. He was appointed Chair of the Board of FortisBC Inc. in 2006. Mr. McWatters has been a Director of FortisBC Inc. since 2005 and a Director of Terasen Inc. since November 2007.

David G. Norris ** Corporate Director, St. John's, NL

Mr. Norris, 60, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey * Corporate Director, Moncton, NB

Mr. Pavey, 60, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey was previously a Director of Maritime Electric Company, Limited.

Roy P. Rideout ** Corporate Director, Halifax, NS

Mr. Rideout, 60, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. He also serves as a Director of the Halifax International Airport Authority and NAV CANADA.

* Audit Committee

★ Governance and Nominating Committee

* Human Resources Committee

Investor Information

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issue, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
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F: 416.263.9394 or 1.888.453.0330
E: service@computershare.com
W: www.computershare.com

Direct Deposit of Dividends

Shareholders may obtain automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis Inc. offers a Dividend Reinvestment Plan⁽¹⁾ and a Consumer Share Purchase Plan⁽²⁾ to Common Shareholders as a convenient method of increasing their investments in Fortis Inc. Participants have dividends plus any optional cash payments (minimum of \$100, maximum of \$20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares are sold quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. Inquiries should be directed to the Transfer Agent, Computershare Trust Company of Canada.

(1) All registered holders of Common Shares who are residents of Canada are eligible to participate in the Dividend Reinvestment Plan. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.

(2) The Consumer Share Purchase Plan is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; and First Preference Shares, Series F of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E and FTS.PR.F, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	\$ 1.531
February 22, 1994	\$ 7.156



Fortis Inc. Officers (l-r): Ronald McCabe, General Counsel and Corporate Secretary; Stan Marshall, President and CEO; Donna Hynes, Assistant Secretary and Manager, Investor and Public Relations; Barry Perry, VP, Finance and CFO

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 9, 2008	August 8, 2008
November 7, 2008	February 6, 2009

Dividend Payment Dates

June 1, 2008	September 1, 2008
December 1, 2008	March 1, 2009

Earnings Release Dates

May 1, 2008	August 8, 2008
October 31, 2008	February 5, 2009

* The declaration and payment of dividends are subject to the Board of Directors' approval.

Analyst and Investor Inquiries

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Annual Meeting

Tuesday, May 6, 2008
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Design and Production:

Colour, St. John's, NL
www.colour-nl.ca

Moveable Inc., Toronto, ON

Printer:

The Lowe-Martin Group,
Ottawa, ON

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Vionetta Burrell, Belmopan, BZ
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Ned Pratt, St. John's, NL
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For contact information on the Fortis Group of Companies, visit the "Contact Us" page of the Fortis Inc. website at www.fortisinc.com.

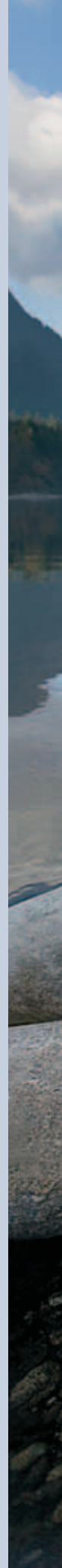


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FORTIS INC.

2008 ANNUAL REPORT



FOCUSED

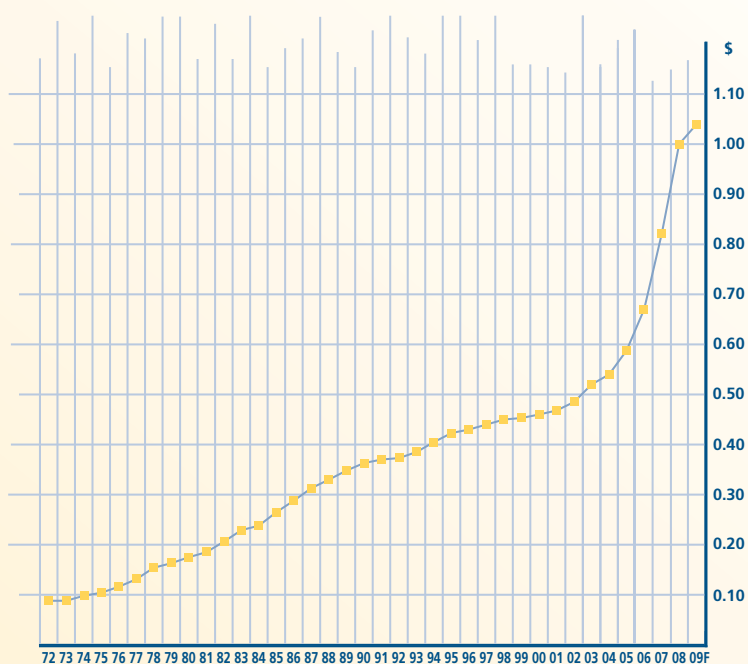


Fortis Inc. is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers.

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Dividends paid per common share

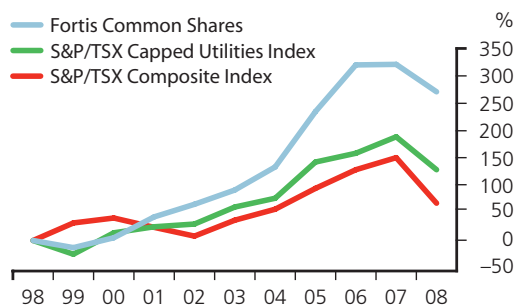


Fortis has increased its annual dividend to common shareholders for 36 consecutive years, the longest record of any public corporation in Canada.

Front Cover Photo: FortisBC employees Matt Wilson (left) and Dan Karslake (right)
Photo taken by Cam Craig, Terasen Gas employee

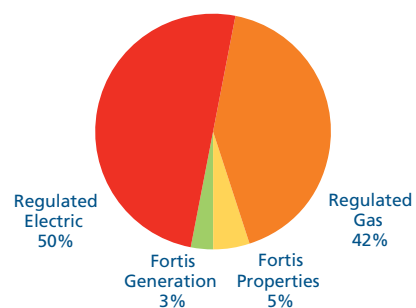
Back Cover Photo: Newfoundland Power Rattling Brook penstock
Photo taken by Gary Murray, Newfoundland Power employee

10-Year Cumulative Total Return



Total Assets Exceed \$11 Billion

(as at December 31, 2008)



Regulated Utility Operations

Gas Operations ♦

Terasen *British Columbia*

Electric Operations ■

FortisAlberta *Alberta*

FortisBC *British Columbia*

Newfoundland Power *Newfoundland*

Maritime Electric *Prince Edward Island*

FortisOntario *Ontario*

Belize Electricity *Belize*

Caribbean Utilities *Grand Cayman*

Fortis Turks and Caicos *Turks and Caicos Islands*

Non-Regulated Operations

Fortis Generation ●

Production Areas

*Belize, Ontario, Central Newfoundland,
British Columbia, Upper New York State*

Fortis Properties ▲

Real Estate

Atlantic Canada, Saskatchewan

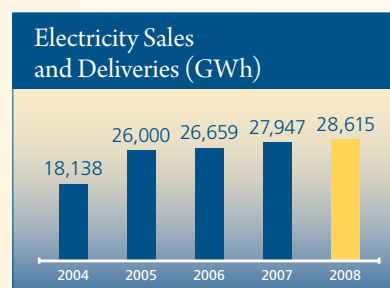
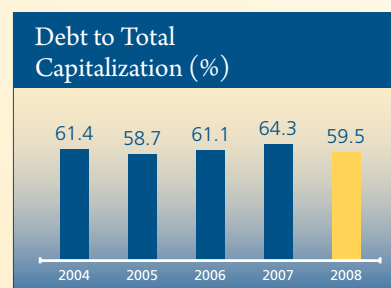
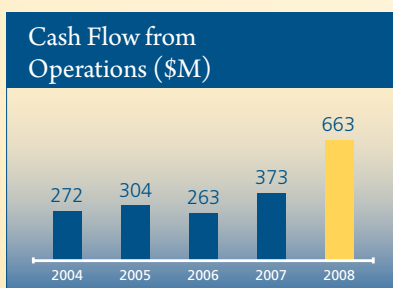
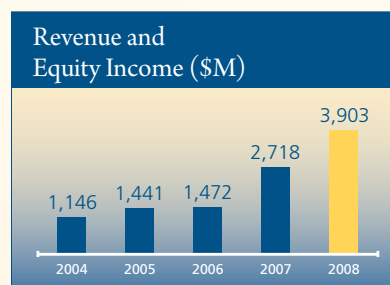
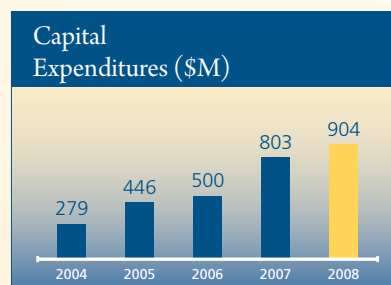
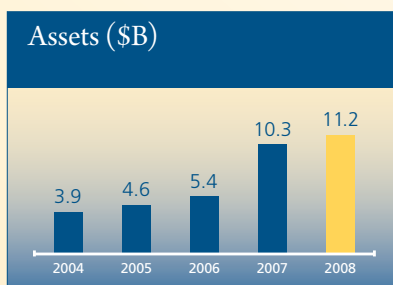
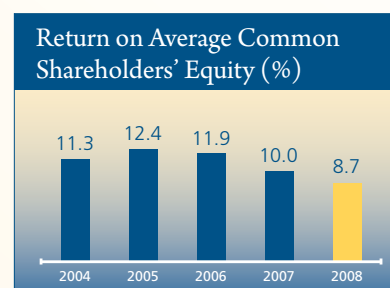
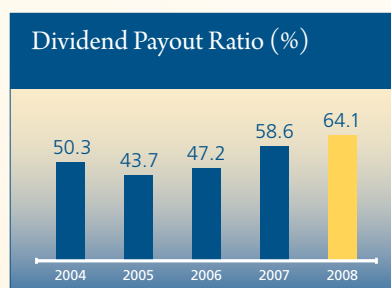
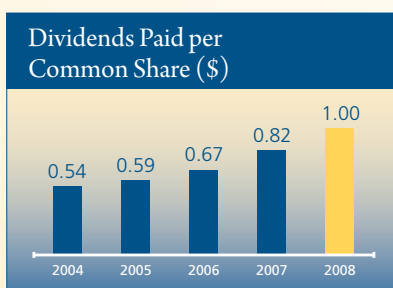
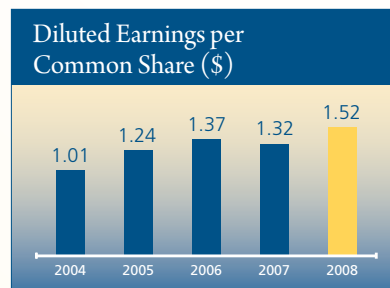
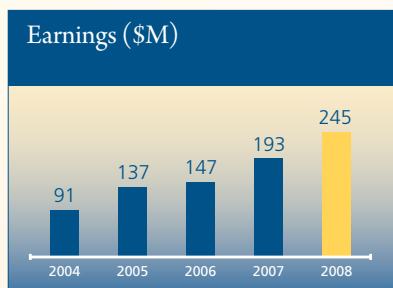
Hotels

*Eastern Canada, Manitoba, Saskatchewan,
Alberta, British Columbia*

Turks and Caicos Islands ■

■ Grand Cayman

■ ● Belize



All financial information is presented in Canadian dollars.

Information is for the fiscal year ended December 31, 2008 unless otherwise indicated.

Regulated

Gas

Terasen ⁽¹⁾	Customers (#)	Employees (#)	Peak Day Demand (TJ)	Gas Volumes (PJ)	Capital Program (\$M)	Total Assets (\$B)	Rate Base (\$B) ⁽²⁾	Earnings (\$M)	Allowed ROE (%) ⁽³⁾	
									2008	2009
Total	931,000	1,260	1,402	221	220	4.6	3.1	118	8.62	8.47

Electric

Company	Customers (#)	Employees (#)	Peak Demand (MW)	Energy Sales (GWh)	Capital Program (\$M)	Total Assets (\$B)	Rate Base (\$B) ⁽²⁾	Earnings (\$M)	Allowed ROE (%) ⁽³⁾	
									2008	2009
FortisAlberta	461,000	991	3,150	15,722	302	1.8	1.3	46	8.75	8.51 ⁽⁴⁾
FortisBC	157,000	545	746	3,087	117	1.2	0.9	34	9.02	8.87
Newfoundland Power	236,000	551	1,181	5,208	67	1.0	0.8	32	8.95	8.95
Maritime Electric	73,000	179	223	1,035	35	0.4	0.3	11	10.00	9.75
FortisOntario	52,000	125	227	1,147	11	0.2	0.1	3	9.00	8.39
Belize Electricity ⁽⁵⁾	74,000	278	74	407	22	0.2	0.2	(4)	10.00 ⁽⁶⁾	10.00 ⁽⁶⁾⁽⁷⁾
Caribbean Utilities ⁽⁸⁾	24,000	197	94	635	44	0.6	0.4	13	9.00–11.00 ⁽⁶⁾	9.00–11.00 ⁽⁶⁾
Fortis Turks and Caicos	9,000	95	29	157	44	0.2	0.2	8	17.50 ⁽⁶⁾⁽⁹⁾	17.50 ⁽⁶⁾
Total	1,086,000	2,961	5,724	27,398	642	5.6	4.2	143		

(1) Terasen primarily includes the operations of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc. and Terasen Gas (Whistler) Inc., collectively known as the "Terasen Gas companies".

(2) Forecast mid-year 2009

(3) Rate of return on common shareholders' equity ("ROE"). For Terasen, ROE is for Terasen Gas Inc. ROE for Terasen Gas (Vancouver Island) Inc. is 70 basis points higher.

(4) Interim ROE pending outcome of regulatory proceeding

(5) Information in table represents 100% of Belize Electricity's operations except for earnings data. Earnings represent Belize Electricity's contribution to the consolidated earnings of Fortis, based on the Corporation's 70.1% ownership interest.

(6) Regulated rate of return on rate base assets ("ROA")

(7) Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application

(8) Fortis holds a 57% interest in Caribbean Utilities. Information in table represents 100% of Caribbean Utilities' operations as at and for the 14 months ended December 31, 2008 due to a change in the utility's fiscal year end. Earnings represent Caribbean Utilities' contribution to the Corporation's consolidated earnings for the 14 months ended December 31, 2008.

(9) Significant investment is currently occurring at the utility. 2008 achieved ROA was lower than the ROA allowed under the licence.

Non-Regulated

Fortis Generation⁽¹⁾

	Generating Capacity (MW)	Energy Sales (GWh)	Assets ⁽³⁾ (\$B)	Earnings ⁽⁴⁾ (\$M)	Capital Program (\$M)
Total	195	1,217	0.4	30	28

Fortis Properties⁽²⁾

	Employees (#)	Assets (\$B)	Earnings ⁽⁴⁾ (\$M)	Capital Program (\$M)
Total	2,000	0.6	23	14

(1) Includes operations in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State

(2) Includes approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada and 20 hotels across Canada

(3) Includes \$126 million in "Other" non-regulated assets

(4) Contribution to Fortis Inc. consolidated earnings for the fiscal year ended December 31, 2008

Information is for the fiscal year ended December 31, 2008 unless otherwise indicated.



Left – The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines and met a peak day demand of 1,402 TJ in 2008.

Right – Fortis electric utilities own and/or operate approximately 136,000 kilometres of transmission and distribution lines and met a combined peak demand of more than 5,700 MW in 2008.

Report to Shareholders

2008 has been another successful year for your company and marks the 9th consecutive year Fortis has delivered record earnings to shareholders.

Fortis achieved net earnings applicable to common shares of \$245 million, 27 per cent higher than earnings of \$193 million in 2007. Earnings per common share were \$1.56, 16 cents higher than earnings per common share of \$1.40 for the previous year.

Growth in earnings, excluding one-time items, was primarily attributable to a full year of earnings from Terasen and increased contributions from non-regulated hydroelectric generation. Earnings in 2008 were enhanced by a one-time \$7.5 million tax reduction (\$5.5 million at the Terasen Gas companies and \$2 million at Terasen Inc.) associated with the settlement of historical corporate tax matters at Terasen but were reduced by a one-time \$13 million charge that represented the Corporation's share of fuel and purchased power costs disallowed by Belize Electricity's regulator.

Dividends paid per common share grew to \$1.00 in 2008, 22 per cent higher than 82 cents paid per common share in the previous year. The dividend payout ratio was approximately 64 per cent in 2008. Fortis increased its quarterly common share dividend to 26 cents, commencing with the first quarter dividend paid in 2009. The 4 per cent increase in the quarterly common share dividend translates into an annualized dividend of \$1.04 and extends the Corporation's record of annual common share dividend increases to 36 consecutive years, the longest record of any public corporation in Canada.

In December, Fortis amended and restated its Dividend Reinvestment and Share Purchase Plan to provide shareholders with a 2 per cent discount on the purchase of common shares, issued from treasury, with reinvested dividends. The discount became effective with dividends paid on March 1, 2009.

Over the past five years, Fortis delivered an average annualized total return of 14.3 per cent, the highest in its sector, and outperformed both the S&P/TSX Capped Utilities Index and S&P/TSX Composite Index, which delivered average annualized total returns of 7.3 per cent and 4.2 per cent, respectively, over that period.

In October 2008, Fortis was placed in the S&P/TSX 60, 60 Capped and Equity 60 indices. The average daily trading volume for the 46 trading days in 2008 that Fortis was a member of these indices was approximately 662,000 common shares, almost 35 per cent higher than the average daily trading volume for the year-to-date period prior to inclusion. Over the past five years, the average daily trading volume of Fortis common shares has increased 4.5 times, exceeding, on average, 525,000 common shares traded daily in 2008.

Fortis is the largest investor-owned distribution utility in Canada, serving more than 2,000,000 gas and electricity customers. At the end of 2008, regulated rate base assets approached \$7 billion; total assets of Fortis exceeded \$11 billion, more than five times the amount five years ago. Growth has been driven by two large acquisitions: the \$3.7 billion acquisition of Terasen in May 2007 and the \$1.5 billion acquisition of FortisAlberta and FortisBC in May 2004. As well, growth has occurred organically through the continued investment in energy infrastructure. Over the past five years, Fortis utilities have invested approximately \$2.9 billion in capital projects to ensure reliability of service to customers and meet growth in energy demand.



Left – Fortis, through its regulated and non-regulated businesses, owns and/or operates more than 1,800 MW of generation, mainly hydroelectric.
Right – The regulated utilities of Fortis serve more than 2,000,000 customers in five Canadian provinces and three Caribbean countries.

Report to Shareholders

2008 marked the largest annual capital investment program in the history of Fortis. Consolidated capital expenditures, before customer contributions, were \$904 million. Much of this investment was driven by the Terasen Gas companies, FortisAlberta, FortisBC and regulated and non-regulated electric utility operations in the Caribbean. Terasen Gas (Vancouver Island) started construction of its approximate \$200 million liquefied natural gas storage facility, which will enhance reliability of supply to customers when it comes into service in late 2011. FortisAlberta continued work on its four-year Automated Meter Infrastructure Project, estimated at a total cost of \$124 million, which will enable customers to better monitor and manage energy consumption. FortisBC received regulatory approval to proceed in 2009 with the \$141 million Okanagan Transmission Reinforcement Project, the largest capital initiative ever to be undertaken by the utility. The project will provide needed system enhancements in the Okanagan region and help ensure the delivery of safe, reliable energy to customers. Construction continued on the US\$53 million 19-megawatt ("MW") Vaca hydroelectric generating facility in Belize. When it comes online, expected at the beginning of 2010, the amount of energy Belize Electricity sources from hydroelectricity, the least-cost source of energy supply available, will increase to approximately 45 per cent.

The Terasen acquisition became accretive to earnings per common share of Fortis in the first quarter of 2008. The Terasen Gas companies contributed \$118 million to earnings for the full year in 2008 compared to \$50 million for the 7½ months of ownership in 2007. Results for 2008 were favourably impacted by an approximate \$5.5 million tax reduction related to the settlement of historical corporate tax matters and a higher allowed rate of return on common shareholder's equity ("ROE") compared to 2007. Results for 2007 included a \$7 million after-tax gain on the sale of surplus land.

Canadian Regulated Electric Utilities contributed earnings of \$126 million compared to \$125 million for 2007. Earnings grew \$5 million year over year, excluding the impact of a one-time gain of \$2 million in 2007 associated with an interconnection agreement-related refund at FortisOntario and the subsequent regulator-required repayment of the refund in 2008 by the utility. The key performance drivers were rate base growth and the higher allowed ROEs at FortisAlberta, FortisBC and Newfoundland Power, partially offset by lower corporate tax recoveries at FortisAlberta.

Customer rates for 2009 have been approved for the four largest utilities, which account for approximately 77 per cent of the total assets of Fortis. The allowed ROEs for 2009 at Terasen Gas Inc. and FortisBC declined slightly to 8.47 per cent and 8.87 per cent, respectively. The allowed ROE for 2009 at Newfoundland Power remains at 8.95 per cent. FortisAlberta is currently engaged in a generic cost of capital proceeding with its regulator and a decision on the utility's allowed ROE for 2009 is not expected until later in the year. In the interim, as directed by its regulator, customer rates for 2009 at FortisAlberta have been set using the utility's allowed ROE for 2007 of 8.51 per cent.

Caribbean Regulated Electric Utilities contributed earnings of \$17 million compared to \$31 million for 2007. Earnings were \$3 million lower year over year, excluding the impact of a one-time loss of \$13 million in 2008 related to a regulatory order received at Belize Electricity, which is being legally contested by the Company, and a one-time loss of \$2 million in 2007 associated with the disposal of steam-turbine assets at Caribbean Utilities. Overall electricity sales growth and two additional months of earnings from Caribbean Utilities, associated with a change in the utility's fiscal year end, were more than offset by the impact of a 3.25 per cent reduction in base electricity rates at Caribbean Utilities, effective January 1, 2008; a lower allowed rate of return on rate base assets ("ROA") at Belize Electricity; and an approximate \$2 million revenue loss at Fortis Turks and Caicos associated with Hurricane Ike.



Over the past five years, Fortis utilities have invested approximately \$2.9 billion in capital projects to ensure reliability of service to customers and meet growth in energy demand.

Report to Shareholders

Non-Regulated Fortis Generation contributed earnings of \$30 million, \$6 million higher than for 2007. Performance was driven by increased hydroelectric production in central Newfoundland, Belize and Upper New York State, as a result of higher rainfall, and higher average wholesale energy prices in Upper New York State and Ontario.

Commencing in May 2009, Fortis will no longer have the benefit of the 75-MW Rankine generating facility in Ontario due to the expiration of the water rights on the Niagara River. However, earnings' projections for Vaca, combined with the planned substantial consolidated capital program over the next couple of years, are expected to more than offset the loss of earnings associated with the expiry of the Rankine water rights.

Fortis Properties delivered earnings of \$23 million compared to \$24 million for 2007. Excluding a \$2 million favourable tax adjustment in 2007, earnings were \$1 million higher year over year, mainly due to a full year of earnings from Delta Regina, which was acquired in August 2007.

Fortis continues to maintain strong investment-grade credit ratings, allowing it to have good access to the debt capital markets. Fortis is rated A- by Standard & Poor's and BBB(high) by DBRS. Its four largest utilities all have strong investment-grade credit ratings.

Fortis and its subsidiaries raised almost \$1.2 billion in the capital markets in 2008. In December, the Corporation completed a \$300 million common share issue, the net proceeds of which were used to repay short-term debt primarily incurred to retire \$200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes. In the second quarter of 2008, Fortis issued preference shares for gross proceeds of \$230 million, the net proceeds of which were mainly used to repay \$170 million borrowed under the Corporation's committed credit facility and to fund subsidiary equity requirements. Canadian Regulated Utilities issued \$660 million of 30-year long-term debt at rates ranging from 5.80 per cent to 6.05 per cent. The proceeds provide long-term funding for capital programs to enhance reliability of gas and electricity service and meet customer growth.

At December 31, 2008, Fortis had consolidated credit facilities of \$2.2 billion, of which \$1.5 billion was unused. Approximately \$2 billion of the total credit facilities are committed facilities, the majority of which have maturities ranging from 2011 to 2013. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities. The Corporation's long-term debt maturities and repayments are expected to average approximately \$180 million annually over the next five years. With its substantial credit facilities and conservative capital structure, we believe Fortis has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009.

Employee success underpins corporate success. To each of our more than 6,200 employees, thank you for your commitment to customers. We extend our appreciation to the Board of Directors of Fortis for your governance and counsel. We also offer our gratitude and best wishes to Dr. Linda Inkpen who retires from the Board in 2009.



Left – The Fortis Emergency Response Network, consisting of more than 60 employees throughout the Fortis Group of Companies, assisted Fortis Turks and Caicos with its restoration efforts following Hurricane Ike, a Category 4 hurricane.

Right – Geoffrey F. Hyland, Chair of the Board, Fortis Inc. (left) and Stan Marshall, President and CEO, Fortis Inc. (right)



Report to Shareholders

Fortis is focused on executing its 2009 consolidated capital program, estimated at approximately \$1 billion, to meet customers' expectations and growth in energy demand. Over the next five years, the consolidated capital expenditure program is expected to be approximately \$4.5 billion, substantially all of which will be funded at the subsidiary level. This capital investment, which will mainly occur in western Canada, will add value for customers and shareholders and fortify the position of Fortis as a leading owner of energy infrastructure in Canada.

On behalf of the Board of Directors,

Geoffrey F. Hyland
Chair of the Board
Fortis Inc.

H. Stanley Marshall
President and Chief Executive Officer
Fortis Inc.

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. In all its operations, Fortis will manage resources prudently and deliver quality service to maximize value to customers and shareholders.

The Corporation will continue to focus on three primary objectives:

- i) The growth in assets and market capitalization should be greater than the average of other North American public gas and electric utilities of similar size.
- ii) Earnings should continue at a rate commensurate with that of a well-run North American utility.
- iii) The financial and business risks of Fortis should not be substantially greater than those associated with the operation of a North American utility of similar size.



Left – Officers of Terasen (back row l-r): Douglas Stout, VP, Marketing and Business Development; Dwain Bell, VP, Distribution; Robert Samels, VP, Business Services and CIO; Cynthia Des Brisay, VP, Gas Supply and Transmission; Roger Dall'Antonia, VP, Corporate Development and Treasurer; (front row l-r): Scott Thomson, VP, Regulatory Affairs and CFO; Jan Marston, VP, HR and Operations Governance; Randall Jespersen, President and CEO; David Bennett, VP, Regulatory Affairs and General Counsel
Right – Terasen began construction on the approximate \$200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island in May 2008.

Terasen

Regulated Gas Operations

Terasen Inc. ("Terasen") is the largest distributor of natural gas in British Columbia, serving 931,400 customers in more than 125 communities or 96 per cent of gas users in the province. The Company delivers more than 20 per cent of the total energy consumed in British Columbia, comparable to the amount of electricity used in the province, making it a significant contributor to the province's energy mix.

Terasen's regulated natural gas and piped-propane distribution business is carried out by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), collectively known as the "Terasen Gas companies". Its operations also include Terasen Energy Services, which designs, owns and operates geothermal systems, community piping and energy-transfer systems to harness renewable energy sources.

TGI, the largest subsidiary of Terasen, provides natural gas transmission and distribution services and propane distribution to approximately 834,000 customers. Its service territory extends from Vancouver to the Fraser Valley and the interior of British Columbia. TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast. The Company serves approximately 95,000 customers. TGWI owns and operates the propane distribution system in Whistler, providing service to approximately 2,400 customers.

The Terasen Gas companies own and operate more than 46,000 kilometres of natural gas distribution and transmission pipelines. In 2008, gas volumes exceeded 221,000 terajoules ("TJ") and a peak day demand of 1,402 TJ was met.

Terasen achieved an all-time high Customer Satisfaction Rating of 79.7 per cent in 2008. The Company has improved its Customer Satisfaction Rating for each of the past five years.

Approximately \$220 million, before customer contributions, was invested in capital programs in 2008 to ensure the safe, reliable delivery of piped energy to customers.

Construction started on the approximate \$200 million 1.5 billion-cubic foot Mount Hayes liquefied natural gas storage facility on Vancouver Island in May 2008. The facility will allow for more efficient use of existing pipeline systems and improve reliability and security of supply during periods of system interruptions or increased energy demand. It is expected to come into service by late 2011.

Construction continued on the 50-kilometre natural gas pipeline from Squamish to Whistler. The pipeline, a key component of the Sustainable Energy Plan of the Resort Municipality of Whistler, is expected to be completed in spring 2009, followed by the conversion of the community's propane system. The total cost of the pipeline and conversion is expected to be approximately \$51 million.

Completed under budget and almost two months ahead of schedule, the \$24 million Vancouver Low-Pressure Replacement Project concluded with the seismic upgrade of 95 kilometres of natural gas distribution pipelines and 7,100 service connections. In addition to ensuring the safety and integrity of the gas distribution system, the project enhances delivery service by accommodating modern high-efficiency appliances.



Left – The four-year Automated Meter Infrastructure (“AMI”) Project, estimated at a total capital cost of \$124 million, entails the scheduled replacement of conventional meters with AMI technology for all FortisAlberta customers by the end of 2010.

Right – Officers of FortisAlberta (l-r): Annette Butt, VP, Human Resources and Corporate Communications; Cynthia Johnston, VP, Regulatory and Legal; Karl Smith, President and CEO; Nipa Chakravarti, VP, Customer Service; Alan Skiffington, VP, Business Services and CIO; Ian Lorimer, VP, Finance and CFO; Phonse Delaney, VP, Operations and Engineering

FortisAlberta

Regulated Electric Operations

FortisAlberta is an electric utility that distributes electricity, generated by other market participants, to end-use customers in southern and central Alberta. Its electricity system includes approximately 108,000 kilometres of distribution lines, which comprise more than 60 per cent of Alberta's total electricity distribution network. The Company serves approximately 461,000 customers in 175 communities and met a peak demand of 3,150 MW in 2008.

FortisAlberta achieved a Customer Satisfaction Rating of 81 per cent in 2008, a marked improvement from its average annual rating for the past three years of 76 per cent.

A record \$302 million, before customer contributions, was invested in capital assets in 2008, primarily to meet growth in customer demand. More than 12,000 new customers were connected to the utility's distribution system. The Company worked closely with the transmission service provider and the Alberta Electric System Operator to add substation capacity, improve reliability and meet customer load growth in Balzac, Tilley, Stavelly, Bruderheim and Blackfalds.

The Automated Meter Infrastructure (“AMI”) Project involved the installation of more than 70,000 electronic meters at customer sites in 2008. AMI technology, which replaces the manual meter reading system, will help reduce operating costs and enable customers to better monitor and manage their energy usage on a monthly basis. The four-year AMI Project, estimated at a total capital cost of \$124 million, entails the scheduled replacement of conventional meters with AMI technology for all FortisAlberta customers by the end of 2010.

Approximately \$50 million was invested in projects to improve system reliability, customer service and safety. Projects included the replacement of more than 4,000 deteriorated poles, the installation of distribution automation equipment in Airdrie and St. Albert to enable fast restoration of service following an outage and the introduction of new technology that involves the injection of silicone to extend the service life of underground cables.

Construction was completed on the utility's \$26 million 88,000-square foot operations and customer service facility in Airdrie. The new facility houses approximately 30 per cent of FortisAlberta's workforce, previously located in leased office space in Calgary. The Company earned the City of Airdrie's 2008 Eco Edge Award as a result of environmental leadership at the new facility, which features innovative environmental considerations including a 95,000-litre rainwater cistern and energy-efficient windows and lighting.

As a result of productivity improvements, FortisAlberta achieved an operating cost per customer of \$209 compared to \$216 in 2007. Better performance was achieved as a result of revised work practices to improve the time to complete projects and enhance work capacity. New conductor installation equipment helped improve field work practices, resulting in increased efficiency and higher quality of work. Efficiencies were also created through the utility's ability to assign resources, bundle work and reduce employee travel time.

The Company implemented an environmental management system consistent with the international ISO 14001 standard. The system and related training initiatives provide a new tool to manage environmental issues and improve operational performance.



Left – Officers of FortisBC (l-r): David Bennett, VP, Regulatory Affairs, General Counsel and Corporate Secretary; Michele Leeners, VP, Finance and CFO; John Walker, President and CEO; Don Debiene, VP, Power Supply and Strategic Planning; Doyle Sam, VP, Engineering and Operations; Michael Mulcahy, VP, Customer and Corporate Services



Right – FortisBC invested approximately \$117 million, before customer contributions, in capital projects in 2008 to meet growing energy demand and replace aging infrastructure.

FortisBC

Regulated Electric Operations

FortisBC is an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers directly and indirectly. Its utility assets include approximately 7,000 kilometres of transmission and distribution lines and four regulated hydroelectric generating plants on the Kootenay River with a combined capacity of 223 MW. The annual gross energy entitlement from the plants is about 1,591 gigawatt hours (“GWh”). FortisBC also manages 904 MW of hydroelectric generation through contract services. It generates approximately 45 per cent of its electricity requirements, with the balance met through power purchase agreements. The Company met a record peak demand of 746 MW in 2008, exceeding the previous record of 718 MW reached in 2006.

FortisBC achieved a Customer Satisfaction Rating of 86 per cent in 2008, consistent with its rating in 2007.

An intense wind storm swept through the utility's service territory in July, causing power outages to approximately 25,000 customers. More than 150 employees, including power-line technicians, call centre and system control centre personnel and meter readers, were involved in safely restoring power to the majority of customers within 24 hours. Call centre personnel fielded more than 5,000 calls during one storm day, ten times the normal daily call volume.

FortisBC is focused on providing the highest level of customer service and ensuring the timely and cost-efficient installation of new service connections. In 2008, 454 residential extension quotes were processed and 1,664 new service installations were completed. Electronic billing (eBills) was introduced, with more than 6,400 customers choosing to receive their electricity bills this way.

In 2008, approximately \$117 million, before customer contributions, was invested in capital projects to meet growing energy demand and replace aging infrastructure. Construction was completed on the \$6.2 million Ootischenia substation, creating an additional source of power supply to the Castlegar area in the West Kootenays. The new substation at Big White ski area, the final phase of the \$20.5 million Big White Project, was commissioned and the \$27 million Kettle Valley Substation Project in Rock Creek was energized. Work began on the \$14.4 million Black Mountain substation and associated distribution line, servicing growth to areas northeast of Kelowna. The first phase of the \$17.2 million Ellison Substation Project in Kelowna began with the upgrading of six kilometres of distribution and transmission lines.

Approximately \$11 million was invested in the utility's ongoing hydroelectric generation Upgrade and Life-Extension Program. The program, which involves rebuilding 11 of the 15 hydroelectric generating units in the Company's four generating stations, is expected to be completed in 2012. The program will improve efficiency, safety and environmental stewardship and maintain the overall reliability of the plants.

Regulatory approval was received in 2008 for the \$141 million Okanagan Transmission Reinforcement Project, the largest capital project to be undertaken by FortisBC. The project entails upgrades to the utility's existing transmission lines and substations and the building of a new 230-kilovolt (“kV”) transmission line and substation. It will provide needed system enhancements in the Okanagan area, ensuring customers have safe and reliable energy as residential and business growth continues in the region. Construction is scheduled to commence spring 2009 with completion in mid-2011.



Left – Newfoundland Power achieved a Customer Satisfaction Rating of 89 per cent in 2008.

Right – Officers of Newfoundland Power (l-r): Jocelyn Perry, VP, Finance and CFO; Gary Smith; VP, Engineering and Operations; Earl Ludlow, President and CEO; Lisa Hutchens, VP, Customer Relations and Corporate Services; Peter Alteen, VP, Regulatory Affairs and General Counsel

Newfoundland Power

Regulated Electric Operations

Newfoundland Power operates an integrated generation, transmission and distribution system in Newfoundland. The Company serves approximately 236,000 customers or 85 per cent of electricity consumers in the province. It owns and operates 30 small generating stations with an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation, and has approximately 11,000 kilometres of transmission and distribution lines. Newfoundland Power met a peak demand of 1,181 MW in 2008. Approximately 92 per cent of its energy requirement is purchased from Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro").

Despite the impact to customers of rising energy prices, Newfoundland Power achieved a Customer Satisfaction Rating of 89 per cent in 2008, slightly higher than the rating achieved in the previous year. Strategic capital investments and employee commitment to customer service enabled electricity to be delivered to customers 99.97 per cent of the time in 2008.

Approximately \$67 million, before customer contributions, was invested in capital projects to help strengthen the electricity system, including \$18.3 million to provide service to new customers. The Company invested \$1.5 million and worked jointly with Newfoundland Hydro and two independent developers to connect 54 MW of renewable wind energy to the island's electricity system. To further enhance system reliability, Newfoundland Power completed a \$3.4 million upgrade of the transmission lines on the Bonavista Peninsula and Southern Shore of the Avalon Peninsula and refurbished several of its substations across the island at a total cost of \$2.4 million. Performance optimization of 43 distribution feeders in high-growth areas was undertaken to prevent power outages and the use of handheld computers was increased to streamline maintenance workflow.

The Company partnered with Newfoundland Hydro to provide customers with the information, tools and programs they need to be energy efficient. The two utilities completed a Five-Year Energy-Conservation Plan with the goal of conserving an estimated 70 GWh of energy annually through 2013, scheduled to begin in 2009. Newfoundland Power became an active partner in the Energy Conservation and Efficiency Partnership under the Government of Newfoundland and Labrador's Energy Plan, coordinating and assisting with energy conservation and efficiency initiatives.

Online connection with customers improved throughout the year. Customer visits to the corporate website increased 20 per cent over the previous year.

Newfoundland Power completed its first year under the internationally recognized OHSAS 18001 Health and Safety Management System standard. Safety education, training and awareness initiatives included comprehensive employee programs dealing with hazard assessment through risk management/job planning, high-voltage electricity switching and safe work practices around de-energized equipment. The Company launched a new contractor website, which provides easy online access to safety training requirements, practices and policies. Electrical safety presentations were delivered to more than 2,600 children in 53 schools throughout the province. Newfoundland Power delivered safety training to 190 firefighters across the island and training was provided to members of the Canadian military in preparation for their power-restoration efforts in Afghanistan.



Left – Officers of Maritime Electric (l-r): John Gaudet, VP, Corporate Planning and Energy Supply; Steve Loggie, VP, Customer Service; Fred O'Brien, President and CEO; Bill Geldert, VP, Finance, CFO and Corporate Secretary



Right – Maritime Electric serves approximately 73,000 customers, or 90 per cent of electricity consumers, on Prince Edward Island.

Maritime Electric

Regulated Electric Operations

Maritime Electric, the principal electric utility on Prince Edward Island ("PEI" or the "Island"), serves approximately 73,000 customers or 90 per cent of electricity consumers in the province. The Company owns and operates a fully integrated system comprised of approximately 5,300 kilometres of transmission and distribution lines, providing for the generation, transmission and distribution of electricity throughout the Island. Maritime Electric maintains on-Island generating facilities at Charlottetown and Borden-Carleton with a combined total capacity of 150 MW. The electricity system is connected to the mainland power grid via two submarine cables under the Northumberland Strait. The utility met a peak demand of 223 MW in 2008.

Maritime Electric purchases approximately 87 per cent of the energy required to serve customers from New Brunswick Power ("NB Power"). It has entitlement to energy and capacity from NB Power's Point Lepreau and Dalhousie Generating Stations through agreements that extend for the life of these stations.

In April 2008, a refurbishment began on the Point Lepreau Generating Station that will extend its life by 25 years and provide additional stability with respect to long-term energy supply. The balance of the Company's energy requirements is obtained from on-Island wind-powered generation facilities and from the utility's own generating plants. Approximately 13 per cent of total energy supply was derived from wind-powered generation in 2008.

The Government of Prince Edward Island requires Maritime Electric to have a total of 30 per cent of its annual energy sales sourced from on-Island wind farms by 2013. The Company is working with the Government of Prince Edward Island and PEI Energy Corporation on the development of additional wind-powered generation. It is expected that a request for proposal for the additional wind-powered energy expansion will be issued by the provincial government by mid-2009.

Approximately \$35 million, before customer contributions, was invested in capital projects to improve system reliability and customer service. Construction continued on the \$14 million 138-kV transmission line and power corridor in western PEI. The 71-kilometre transmission line will deliver wind-powered energy from current and future commercial operations in western PEI to the North American grid. The power corridor, which will be jointly funded by the Government of Prince Edward Island and SUEZ Energy North America, will facilitate further expansion of wind-powered generation.

Despite the impact of high world fossil fuel prices on the cost of energy purchased to meet the Island's energy demand, Maritime Electric achieved a Customer Satisfaction Rating of 80 per cent in 2008 compared to 73 per cent for the previous year. Several customer service initiatives were completed in 2008, including an upgrade of the Company's website. A number of new and improved website features were added, such as the Energy Calculator, which will assist customers in better understanding and managing their electricity consumption.



Left – By mid-2009, FortisOntario is scheduled to begin the installation of smart meters, which track time-of-use consumption data.

Right – Officers of FortisOntario (l-r): Scott Hawkes, VP, Corporate Services, General Counsel and Corporate Secretary; Glen King, VP, Finance and CFO; William Daley, President and CEO; Angus Orford, VP, Operations

FortisOntario

Regulated Electric Operations

FortisOntario is an integrated electric utility which owns and operates Canadian Niagara Power and Cornwall Electric and serves approximately 52,000 customers, mainly in Fort Erie, Port Colborne, Cornwall and Gananoque, Ontario. Its regulated assets include approximately 1,570 kilometres of distribution and transmission lines in the Niagara and Cornwall regions, including an international interconnection between New York State and Fort Erie. FortisOntario owns a 10 per cent interest in Westario Power Inc. and Rideau St. Lawrence Holdings Inc., two regional electric distribution companies that together serve more than 27,000 customers. The Company purchases its electricity from the Independent Electricity System Operator in Ontario, with the exception of Cornwall Electric which is supplied by Hydro-Québec. FortisOntario met a combined peak demand of 227 MW in 2008.

In October 2008, the Company entered into a definitive agreement to acquire a 10 per cent strategic ownership in the electricity distribution business of Grimsby Power Inc., which serves approximately 10,000 distribution customers in the western area of the Niagara region. The transaction has been approved by the Ontario Energy Board ("OEB") and is pending approval from the Ontario Ministry of Finance.

The Company achieved an overall Customer Satisfaction Rating of 84 per cent in 2008, slightly higher than its rating for the previous year. Customers continue to rate the utility's reliability/safe delivery of electricity and quality of service at 91 per cent and 88 per cent, respectively.

FortisOntario again exceeded performance standards set by the OEB with respect to response times, service connections and call answer statistics. OEB standards will be expanded in 2009 and the Company will ensure all reporting requirements are met.

FortisOntario undertook two electricity conservation and demand management programs during the year. Almost 700 customers enrolled in the Summer Sweepstakes Program, which encouraged customers to reduce their electricity consumption by 10 per cent in July and August.

The Company invested \$11 million, before customer contributions, in capital projects involving new service connections and rebuild projects designed to improve the safety and reliability of its distribution systems. In Port Colborne, construction began on a new \$1.5 million substation that will support load growth and replace an existing substation near the end of its useful life.

The Government of Ontario has mandated all regulated electric utilities in the province to install smart meters, which track time-of-use consumption data, at customer sites by the end of 2010. During 2008, FortisOntario selected a supplier of smart meters and installation of this new technology is scheduled to begin by mid-2009. Approximately 27,000 of the utility's metered customers will move to time-of-use rates by the end of 2010.



Left – Officers of Belize Electricity (l-r): Juliet Estell, Manager, Executive Services and Company Secretary; Curtis Eck, VP, Customer Care and Operations; Lynn Young, President and CEO; Rene Blanco, VP, Finance & Administration and CFO; Joseph Sukhnandan, VP, Engineering and Energy Supply
 Right – Belize Electricity earned a record Customer Satisfaction Rating of 86 per cent in 2008.

Belize Electricity

Regulated Electric Operations

Belize Electricity is the primary distributor of electricity in Belize, Central America. Serving approximately 74,000 customers, the utility met a peak demand of 74 MW in 2008 from multiple sources of energy, including power purchases from Belize Electric Company Limited ("BECOL"), Comisión Federal de Electricidad ("CFE") (the Mexican state-owned power company), Hydro Maya Limited and its own diesel-fired and gas-turbine generation. All major load centres are connected to the country's national electricity system, which is interconnected with the Mexican national electricity grid, allowing the Company to optimize its power supply options. Belize Electricity has an installed generating capacity of 34 MW and owns approximately 2,840 kilometres of transmission and distribution lines. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.

The ability of Belize Electricity to meet the energy needs of its customers was significantly challenged by regulatory decisions received in 2008. During the year, the Company was forced to delay several planned initiatives aimed at system expansion and improvement as a result of a US\$12.5 million limit on capital expenditures imposed by the Public Utilities Commission of Belize.

While regulatory approval was granted in the latter part of the year to complete rural electrification projects and build interconnection facilities to connect with new generation sources, cash flow challenges continued to restrict Belize Electricity's ability to proceed with these projects and other key capital works. Revisions were made to various project schedules to reflect the capital work suspensions, including the construction of substations to connect with independent power producers, now scheduled for completion in the second quarter in 2009.

The Company invested approximately \$22 million, before customer contributions, in capital expenditures in 2008. Projects completed during the year included the connection of several rural communities in the Belize and Cayo Districts to the national grid and the construction of an alternate feeder to serve the popular tourist destination of Placencia Village in Southern Belize. The new feeder will address Placencia's load growth, provide an alternate distribution line to the service area and enable service upgrades with fewer interruptions. A US\$2 million mobile substation was also procured to maintain service while substation repairs and maintenance are being carried out.

The Company signed a revised Power Purchase Agreement ("PPA") with CFE during the year. Under the revised contract, Belize Electricity has the option to purchase up to 50 MW of energy at a firm rate with the option to purchase the 50 MW of energy at an economic rate if available and less expensive. The utility also signed a PPA with Belize Aquaculture Limited for the supply of approximately 15 MW of power sourced from a heavy fuel oil-fired generating facility in Southern Belize. Connection to the utility's electricity system, which is expected to occur in the second quarter of 2009, will enable the facility to provide backup power to improve system reliability. It will also reduce reliance on Belize Electricity's diesel generators, which are more costly to operate.

Despite the significant operational constraints imposed as a result of the regulatory decisions received, the Company earned a record Customer Satisfaction Rating of 86 per cent in 2008. Several improvement initiatives focused on enhancing service delivery. Operational regions were defined and a service-order management team was established to ensure customer requests are met expeditiously. As well, several new line vehicles were purchased and deployed to various load centres as necessary.



Left – Caribbean Utilities' electricity system has an installed generating capacity of approximately 137 MW and the Company met a record peak demand of 94 MW in 2008.

Right – Officers of Caribbean Utilities (l-r): Douglas Murray, Corporate Secretary; David Watler, VP, Production; Letitia Lawrence, VP, Finance and CFO; Richard Hew, President and CEO; Andrew Small, VP, Transmission and Distribution

Caribbean Utilities

Regulated Electric Operations

Caribbean Utilities generates, transmits and distributes electricity to more than 24,000 customers on Grand Cayman, Cayman Islands. The utility owns and operates approximately 555 kilometres of transmission and distribution lines and 24 kilometres of high-voltage submarine cable. Its electricity system has an installed generating capacity of approximately 137 MW and the Company met a record peak demand of 94 MW in 2008.

The Class A Ordinary Shares of Caribbean Utilities are listed in US funds on the Toronto Stock Exchange under the symbol CUP.U. Fortis has an approximate 57 per cent controlling ownership interest in the utility.

Caribbean Utilities is one of the most reliable and efficient utilities in the Caribbean region. A Customer Satisfaction Rating of 90 per cent was achieved in 2008 compared to 84 per cent in 2007. For the six-month period ended October 31, 2008, an Average Service Availability Index of 99.9 per cent was posted, with customers experiencing, on average, a total of less than one hour of outages for that period.

The Company successfully completed a Class A Ordinary Share Rights Offering (the "Offering") and related stand-by agreement in August 2008. Under the Offering, Caribbean Utilities raised US\$28.2 million, the proceeds of which are supporting the ongoing capital programs necessary to meet energy demand and sustain reliability in the existing generation, transmission and distribution infrastructure.

Capital investments totalled approximately \$44 million in 2008. A significant project included ongoing work to complete the 69-kV distribution line from Rum Point to Old Man Bay. Under a strategic alliance relationship, Caribbean Utilities has contracted MAN Diesel SE to manufacture, install and commission an additional 16 MW of capacity, scheduled for completion in September 2009, which will bring total installed MAN Diesel SE supplied generation to approximately 66 MW.

The Company continues to offer its Energy Smart Program to promote energy conservation and has been conducting complementary Energy Smart audits for customers for six years. Caribbean Utilities also participated in the Chamber of Commerce Business Expo, a three-day event that showcased local businesses and attracted more than 3,000 visitors.

The Company continues to demonstrate its environmental commitment through its ISO 14001:2004 registered Environmental Management System associated with its generation operations. Employee-development initiatives continue to demonstrate the ongoing commitment to the "Investors in People" certification that Caribbean Utilities achieved in 2006. The utility awarded a scholarship for the Masters Program in Renewable Energy Development at Heriot-Watt University in Scotland.

As part of its initiative to enhance specialized employee skills to meet future energy demand, Caribbean Utilities is focused on the ongoing apprenticeship training of employees who work in areas such as operations, mechanical and electrical. The Company implemented a management development program accredited by the Institute of Leadership and Management, one of the main organizations for supervisory training in the United Kingdom, for all supervisory staff.

Caribbean Utilities launched an electrical safety education program for schools on Grand Cayman. The program uses a model city to demonstrate electrical hazards associated with transmission and distribution systems as well as residential electricity use.



Left – Officers of Fortis Turks and Caicos (l-r): Ruth Gardiner-Forbes, VP, Finance and CFO; Ernest Jackson, VP, Generation and Engineering; Eddinton Powell, President and CEO; Brian Walsh, VP, Operations; Allan Robinson, VP, Customer and Corporate Services



Right – Fortis Turks and Caicos serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands.

Fortis Turks and Caicos

Regulated Electric Operations

Fortis Turks and Caicos serves more than 9,000 customers, or 85 per cent of electricity consumers, on the Turks and Caicos Islands. The Company owns and operates a fully integrated system providing for the generation, transmission and distribution of electricity in Providenciales, North Caicos and Middle Caicos pursuant to a 50-year licence that expires in 2037. Fortis Turks and Caicos also owns and operates an independent generating station and transmission and distribution system on South Caicos and is the sole provider of electricity for that island pursuant to a 50-year licence that expires in 2036. In May, the Company began supplying electricity to Dellis Cay. Its regulated assets include 335 kilometres of transmission and distribution lines. The utility has a combined diesel-fired generating capacity of 48 MW and met a combined peak demand of 29 MW in 2008.

While challenged by increasing energy prices and severe weather conditions, the Company achieved a Customer Satisfaction Rating of 75 per cent in 2008.

In early September 2008, the Turks and Caicos Islands were struck by Tropical Storm Hanna followed by Hurricane Ike, a Category 4 hurricane which caused major damage to the utility's transmission and distribution system on South Caicos, with lesser damage occurring on North Caicos and Middle Caicos. Providenciales, the Company's major service territory and home to 80 per cent of its customers, was spared a direct hit. Generation facilities sustained minimal impact as a result of the hurricane. The Fortis Emergency Response Network, consisting of more than 60 employees throughout the Fortis Group of Companies, assisted Fortis Turks and Caicos with its restoration efforts. By the end of October, electricity had been restored to all customers ready to receive service.

Capital expenditures of approximately \$44 million, before customer contributions, in 2008 primarily reflected investment in generation, transmission and distribution infrastructure, information technology platforms and systems, as well as land purchases necessary to meet energy demand and improve customer service.

The 2008/09 Generation Expansion Project is on schedule and will increase the Company's generating capacity by approximately 7 MW with the commissioning of two Caterpillar 3612 series units in early 2009. Capital projects undertaken to improve transmission and distribution reliability included the completion of dedicated underground feeders to Beaches Resort, the Islands' largest hotel, and the Provo Water Plant; the installation of a second power transformer at Grace Bay substation; and the completion of a transmission loop to Grace Bay substation. As a result of these initiatives, Fortis Turks and Caicos experienced a marked reduction in feeder outages in 2008.

New service connections included a number of large customers, among them Seven Stars Resort, Niki Beach Resort and Beach Club Resort.

The Company continued to implement recommendations from its environmental impact evaluation study. An environmental officer designate was appointed and received environmental training from Fortis Group personnel. Fortis Turks and Caicos plans to implement an environmental management system in 2009 that will be consistent with the international ISO 14001 standard by 2012.



Left – Construction of the US\$53 million 19-MW Vaca hydroelectric generating facility on the Macal River in Belize is scheduled for completion at the beginning of 2010.
Right – Fortis Generation has a combined generating capacity of 195 MW, 190 MW of which is hydroelectric generation.

Fortis Generation

Non-Regulated Operations

Fortis Generation includes the operations of non-regulated generating assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State with a combined generating capacity of 195 MW, 190 MW of which is hydroelectric generation.

In Belize, BECOL owns and operates the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities located on the Macal River. Mollejon and Chalillo are the largest commercial hydroelectric generating facilities in Belize. Energy production hit a record high of 192 GWh in 2008 due to above-average rainfall. The Belize Meteorological Office confirmed that the flood-control features of the Chalillo facility significantly reduced the impact on downstream communities of widespread flooding related to heavy rainfall in November. Construction of the US\$53 million 19-MW Vaca hydroelectric generating facility continued and is scheduled for completion at the beginning of 2010. Vaca, a run-of-river plant situated approximately five kilometres downstream from Mollejon, is the final phase of the three-part hydroelectric development plan for the Macal River. BECOL sells its entire output to Belize Electricity under a 50-year PPA. Belize Electricity has signed a 50-year PPA with BECOL for the purchase of energy generated by Vaca. When it comes online, Vaca is expected to increase the average annual energy production from the Macal River by approximately 80 GWh to 240 GWh.

In Ontario, non-regulated operations include 75 MW of water-right entitlement associated with the Rankine hydroelectric generating station at Niagara Falls, which expires in April 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW. With the exception of the cogeneration plant in Cornwall, the electricity produced from these facilities is sold in Ontario at market prices.

In central Newfoundland, Fortis Generation holds a 51 per cent interest in the Exploits River Hydro Partnership ("Exploits Partnership") with Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"). The Exploits Partnership was established in 2001 and commenced operations in 2003 following the development of additional capacity at Abitibi-Consolidated's two hydroelectric generating plants in central Newfoundland. The Exploits Partnership achieved annual production of 177 GWh in 2008. In December 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of Abitibi-Consolidated's assets in Newfoundland including those assets associated with the generation of electricity, some of which included the capital assets of the Exploits Partnership. The provincial government has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated in the province.

In British Columbia, the non-regulated generating asset is the 16-MW run-of-river Walden hydroelectric generating plant near Lillooet, which was acquired in May 2004 as part of the assets of FortisBC. The plant sells its entire output to BC Hydro under a long-term contract.

In Upper New York State, the non-regulated generating assets are four hydroelectric generating stations located in Moose River, Philadelphia, Dolgeville and Diana. The plants have a combined capacity of approximately 23 MW. The average annual 85 GWh of energy output from these modern facilities is sold at the wholesale level through a series of renewable contracts.



Left – Officers of Fortis Properties (l-r): Terry Chaffey, VP, Real Estate; Nora Duke, President and CEO; Jamie Roberts, VP, Finance and CFO

Right – In November 2008, Fortis Properties acquired Hotel Newfoundland. The 4½-star hotel, situated in historic downtown St. John's, features 301 guest rooms and approximately 16,000 square feet of premium meeting space, including 17 conference and special event rooms.

Fortis Properties

Non-Regulated Operations

Fortis Properties owns and operates 20 hotels, offering more than 3,800 rooms, in eight Canadian provinces and approximately 2.8 million square feet of commercial office and retail space primarily in Atlantic Canada. The Company, a wholly owned subsidiary of Fortis, is the primary vehicle for non-utility diversification and growth.

The Hospitality Division continued to demonstrate strong growth through property enhancement, expansion and acquisition. Revenue per available room increased for the 13th consecutive year, reaching \$80.39, primarily due to a higher average daily room rate. In November 2008, Fortis Properties acquired Hotel Newfoundland for approximately \$22 million. The 4½-star hotel, situated in historic downtown St. John's, features 301 guest rooms and approximately 16,000 square feet of premium meeting space, including 17 conference and special event rooms. Aligning with guest expectations for a high-quality service experience, this premier hotel was rebranded as Sheraton Hotel Newfoundland in early 2009. Over the next three years, an approximate \$9 million capital investment will be made to upgrade the hotel.

A \$14 million 70-room expansion of Holiday Inn Express Kelowna commenced in 2008, which includes the addition of an exclusive executive floor, business and family suites, more meeting space, an enhanced fitness facility and two indoor waterslides. A \$0.7 million expansion of the Four Points by Sheraton Conference Centre in Halifax, Nova Scotia was completed during the year. The project utilized space in the Maritime Centre, enabling the hotel to attract larger groups and conventions while providing enhanced service for real estate tenants. The expanded facility includes 12,000 square feet of convention space, in-house audiovisual technology services and courtyard meeting space.

The Real Estate Division's stable performance is supported by long-term leases with quality tenants and strong tenant relations. The year-end occupancy rate was 96.8 per cent, outpacing the national rate of 93.3 per cent. Company buildings have virtually zero vacancy in a number of downtown markets, including St. John's and Halifax. Capital improvements to real estate assets included a \$1.4 million investment at Brunswick Square for electrical equipment replacement and entrance renovations and upgrades.

Approximately \$0.7 million was invested in technology solutions to improve productivity and provide optimal customer service. A new financial management system was installed and a multiphase project to install a new payroll system is ongoing.

The Hospitality Division continued to demonstrate quality customer service. The Delta St. John's Hotel and Conference Centre won *Hospitality Newfoundland and Labrador's Accommodation of the Year Award* for demonstrating dedication to quality service, commitment to the tourism industry and community contribution. For the 11th consecutive year, Holiday Inn Peterborough-Waterfront won the *Readers' Choice Award for Best Hotel in Peterborough* from the region's newspaper, *The Peterborough Examiner*.

Significant emphasis continued to be placed on ensuring compliance with health and safety regulations and raising awareness of health and safety practices. Safety audits were conducted at all properties in 2008.

Leadership development remains a priority as Fortis Properties continues to focus on the growth of high-potential employees through mentoring, professional development courses, special projects, temporary assignments, lateral moves and job promotion.



In 2008, almost \$3 million in financial and in-kind donations was distributed to a wide selection of well-deserving community causes.

Our Community

Fortis remains focused on making a difference in the communities where our employees work and live. In 2008, almost \$3 million in financial and in-kind donations was distributed to a wide selection of well-deserving community causes. Hundreds of employees throughout the Fortis Group of Companies were there to help.

Terasen sponsored the *2008 Environmental Mind Grind* organized by the Environmental Educators of the Central Okanagan Heroes. The event motivated 95 school teams and 450 students throughout British Columbia to display their environmental stewardship knowledge in a game show-style trivia contest.

FortisAlberta employees in Calgary, Red Deer and Edmonton raised \$25,000 for the *CIBC Run for the Cure* in 2008. It was a record-setting year for participation by employees, who raised twice the amount collected in 2007.

FortisBC employees came together and raised almost \$6,000 for the *Hour Kids Campaign*, a fundraiser to help complete upgrades to the maternity and pediatric departments at the Kootenay Boundary Regional Hospital.

Newfoundland Power employees were recognized with a national award at the 9th annual Canadian Blood Services *Honouring Our Lifeblood* event. Since joining the *Partners for Life* program in 2004, employees have made more than 1,400 blood donations.

Maritime Electric offered its *Electrical Safety Presentation* as part of the Grade Six science and math curriculum throughout the school system on Prince Edward Island.

FortisOntario donated \$5,000 to the *Port Cares Reach Out Centre* in Port Colborne. The Centre offers a drop-in service and meal program, serving approximately 12,000 meals to the general public each year.

Belize Electricity awarded a three-year scholarship, valued at BZ\$36,000 per annum, to a Belizean student to pursue a *Diploma in Engineering Technology* at the College of the North Atlantic in Newfoundland.

Caribbean Utilities enhanced its partnership with the *Central Caribbean Marine Institute*, an international non-profit organization that is extending its Coral Reef Awareness Program to schools across Grand Cayman through its Ocean Literacy education curriculum.

Fortis Turks and Caicos joined the campaign to redevelop the sport of cricket on the Turks and Caicos Islands by making a \$4,000 donation and becoming the title sponsor of the *Provo Cricket Association's Men's League*.

Fortis Properties was the title sponsor of the *Business Community Anti-Poverty Initiative Annual Golf Tournament* in New Brunswick. Through its participation during the past six years, the Company has assisted in raising more than \$240,000 in support of the Resource Centre for Youth in Saint John.

Management Discussion and Analysis



Barry Perry, VP, Finance and CFO, Fortis Inc.

Dated March 11, 2009

The following Management Discussion and Analysis ("MD&A") should be read in conjunction with the 2008 Consolidated Financial Statements and Notes to the 2008 Consolidated Financial Statements included in the Fortis Inc. ("Fortis" or the "Corporation") 2008 Annual Report. The MD&A has been prepared in accordance with National Instrument 51-102 – *Continuous Disclosure Obligations*. Financial information in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and is presented in Canadian dollars unless otherwise specified.

Fortis includes forward-looking information in the MD&A within the meaning of applicable securities laws in Canada ("forward-looking information"). The purpose of the forward-looking information is to provide management's expectations regarding the Corporation's future growth, results of operations, performance, business prospects and opportunities, and it may not be appropriate for other purposes. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking

information reflects management's current beliefs and is based on information currently available to the Corporation's management. The forward-looking information in the MD&A includes, but is not limited to, statements regarding: the expected timing of regulatory decisions; the electricity sales growth rate expected at the Corporation's regulated utilities in the Caribbean in 2009; consolidated forecasted gross capital expenditures for 2009 and in total over the next five years, as well as the expected significant capital projects in 2009 and their expected costs and time to complete; the expected impacts on Fortis of the downturn in the global economy; the expected increase in activities at Terasen Energy Services; no significant decrease in subsidiary operating cash flows is expected in 2009; the subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs; the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009; expected long-term debt maturities and repayments in 2009 and on average annually over the next five years; no material increase in interest expense and/or fees associated with renewed and extended credit facilities is expected in 2009; no material adverse credit rating actions are expected in the near term; the expected impact of a change in the US dollar-to-Canadian dollar foreign exchange rate on basic earnings per common share in 2009; the estimated impact a decrease in revenue at Fortis Properties' Hospitality Division would have on basic earnings per common share; the expectation that counterparties to the Terasen Gas companies' gas derivative contracts will continue to meet their obligations; and the expectation of no material increase in defined benefit pension expense in 2009. The forecasts and projections that make up the forward-looking information are based on assumptions which include, but are not limited to: the receipt of applicable regulatory approvals and requested rate orders; no significant operational disruptions or environmental liability due to a catastrophic event or environmental upset caused by severe weather, other acts of nature or other major event; the continued ability to maintain the gas and electricity systems to ensure their continued performance; no significant decline in capital spending in 2009; no severe and prolonged downturn in economic conditions; sufficient liquidity and capital resources; the continuation of regulator-approved mechanisms to flow through the commodity cost of natural gas and energy supply costs in customer rates; the continued ability to hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices; no significant variability in interest rates; no significant counterparty defaults; the continued competitiveness of natural gas pricing when compared with electricity and other alternative sources of energy; the continued availability of natural gas supply; the continued ability to fund defined benefit pension plans; the absence of significant changes in government energy plans and environmental laws that may materially affect the operations and cash flows of the Corporation and its subsidiaries; maintenance of adequate insurance coverage; the ability to obtain and maintain licences and permits; retention of existing service areas; no material decrease in market energy sales prices; favourable relations with First Nations; favourable labour relations; and sufficient human resources to deliver service and execute the capital program. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: regulatory risk; operating and maintenance risks; economic conditions; capital resources and liquidity risk; weather and seasonality; an ultimate resolution of the Exploits River Hydro Partnership that differs from what is currently expected by management; commodity price risk; derivative financial instruments and hedging; interest rate risk; counterparty risk;

Management Discussion and Analysis

competitiveness of natural gas; natural gas supply; defined benefit pension plan performance and funding requirements; risks related to the development of the Terasen Gas (Vancouver Island) Inc. franchise; the Government of British Columbia's Energy Plan; environmental risks; insurance coverage risk; an unexpected outcome of legal proceedings currently against the Corporation; licences and permits; loss of service area; market energy sales prices; transition to International Financial Reporting Standards; changes in tax legislation; First Nations' lands; labour relations and human resources. For additional information with respect to the Corporation's risk factors, reference should be made to the Corporation's continuous disclosure materials filed from time to time with Canadian securities regulatory authorities and to the heading "Business Risk Management" in this MD&A for the year ended December 31, 2008.

All forward-looking information in the MD&A is qualified in its entirety by the above cautionary statements and, except as required by law, the Corporation undertakes no obligation to revise or update any forward-looking information as a result of new information, future events or otherwise after the date hereof.

Corporate Overview and Strategy

Fortis is the largest investor-owned distribution utility in Canada serving more than 2,000,000 gas and electricity customers. Its regulated holdings include electric utilities in five Canadian provinces and three Caribbean countries and a natural gas utility in British Columbia. Fortis owns non-regulated generation assets, primarily hydroelectric, across Canada and in Belize and Upper New York State and hotels and commercial real estate in Canada. In 2008, the Corporation's electricity distribution systems met a combined peak electricity demand of more than 5,700 megawatts ("MW") and its gas distribution systems met a peak day demand of 1,402 terajoules ("TJ").

The vision of Fortis is to be the world leader in those segments of the regulated utility industry in which it operates and the leading service provider within its service areas. Fortis has adopted a strategy of profitable growth with earnings per common share as the primary measure of performance. The Corporation's first priority is to pursue organic growth opportunities in existing operations. Additionally, Fortis pursues profitable growth through acquisitions.

The key goals of the Corporation's regulated utilities are to operate sound gas and electricity distribution systems, deliver gas and electricity safely and reliably to customers at reasonable rates, and conduct business in an environmentally responsible manner. The Corporation's main business, utility operations, is highly regulated. It is segmented by franchise area and, depending on regulatory requirements, by the nature of the assets. The operating segments of the Corporation are: (i) Regulated Gas Utilities – Canadian; (ii) Regulated Electric Utilities – Canadian; (iii) Regulated Electric Utilities – Caribbean; (iv) Non-Regulated – Fortis Generation; (v) Non-Regulated – Fortis Properties; and (vi) Corporate and Other. The earnings of the Corporation's regulated utilities are primarily determined under traditional cost of service and rate of return methodologies. Earnings of the Canadian regulated utilities are generally exposed to changes in interest rates which factor into customer rate-setting mechanisms.

Fortis holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's non-regulated generation assets operate in three countries and have a combined generating capacity of 195 MW, mainly hydroelectric. Except for non-regulated hydroelectric generation operations in Belize and British Columbia, the Corporation's non-regulated generation operations are owned and/or managed by Fortis Properties to ensure standard operating practices, enable leveraging of expertise across the various jurisdictions and allow the pursuit of non-regulated hydroelectric projects. The Corporation's investments in non-regulated assets provide for financial, tax and regulatory flexibility and enhance shareholder return.

The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGV") and Terasen Gas (Whistler) Inc. ("TGW"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

Management Discussion and Analysis

TGI is the largest distributor of natural gas in British Columbia, serving approximately 834,000 residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving approximately 95,000 residential, commercial and industrial customers.

In addition to providing transmission and distribution ("T&D") services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to approximately 2,400 residential and commercial customers.

Regulated Electric Utilities – Canadian

- a. *FortisAlberta*: FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta, serving approximately 461,000 customers.
- b. *FortisBC*: Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia, serving more than 157,000 customers. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 MW. Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.
- c. *Newfoundland Power*: Newfoundland Power is the principal distributor of electricity in Newfoundland, serving approximately 236,000 customers. Newfoundland Power has an installed generating capacity of approximately 140 MW, of which 97 MW is hydroelectric generation.
- d. *Other Canadian*: Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island, serving approximately 73,000 customers. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to approximately 52,000 customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a 10-year lease agreement that expires in April 2012.

Regulated Electric Utilities – Caribbean

- a. *Belize Electricity*: Belize Electricity is the principal distributor of electricity in Belize, Central America, serving approximately 74,000 customers. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.
- b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands, serving more than 24,000 customers. The Company has an installed generating capacity of approximately 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

Management Discussion and Analysis

- c. *Fortis Turks and Caicos*: Includes P.P.C. Limited and Atlantic Equipment & Power (Turks and Caicos) Ltd. Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands, serving more than 9,000 customers. The Company has a combined diesel-fired generating capacity of 48 MW.

Non-Regulated – Fortis Generation

The following summary describes the Corporation's non-regulated generation assets by location:

- a. *Belize*: Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.
- b. *Ontario*: Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.
- c. *Central Newfoundland*: Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary, Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation ("Newfoundland Hydro") under a 30-year power purchase agreement expiring in 2033. For a further discussion of the Exploits Partnership and pending changes related to it refer to the "Liquidity and Capital Resources – Cash Flow Requirements" and "Critical Accounting Estimates – Contingencies" sections of this MD&A.
- d. *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.
- e. *Upper New York State*: Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the US Federal Energy Regulatory Commission. Hydroelectric operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen Inc. corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. While currently not significant, financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

Management Discussion and Analysis

Financial Highlights

For the Years Ended December 31	2008	2007	Variance (%)
Net Earnings Applicable to Common Shares (\$ millions)	245	193	26.9
Basic Earnings per Common Share (\$)	1.56	1.40	11.4
Diluted Earnings per Common Share (\$)	1.52	1.32	15.2
Weighted Average Number of Common Shares Outstanding (millions)	157.4	137.6	14.4
Revenue (\$ millions)	3,903	2,718	43.6
Dividends Paid per Common Share (\$)	1.00	0.82	22.0
Return on Average Common Shareholders' Equity (%)	8.7	10.0	(13.0)
Total Assets (\$ millions)	11,178	10,273	8.8
Cash Flow From Operating Activities (\$ millions)	663	373	77.7

Acquisitions: In November 2008, Fortis Properties acquired the Fairmont Newfoundland hotel for approximately \$22 million, increasing hospitality operations by 301 rooms and 16,000 square feet of convention space.

On May 17, 2007, Fortis completed the acquisition of all of the issued and outstanding common shares of Terasen, formerly a wholly owned subsidiary of Kinder Morgan, Inc., for aggregate consideration of \$3.7 billion, including the assumption of approximately \$2.4 billion of consolidated debt. Terasen owns and operates a gas distribution business carried on by TGI, TGV and TGV. The acquisition did not include the petroleum transportation assets of Kinder Morgan Canada (formerly Terasen Pipelines), which are comprised primarily of refined and crude oil pipelines.

A significant portion of the net cash purchase price of Terasen was satisfied with the net proceeds of the public offering of Subscription Receipts completed by Fortis on March 15, 2007. Fortis issued approximately 44.3 million Subscription Receipts for gross proceeds of approximately \$1.15 billion. Upon closing of the acquisition on May 17, 2007, each Subscription Receipt was automatically exchanged, without payment of additional consideration, for one common share of Fortis. The remaining net cash purchase price was financed, on an interim basis, by drawing \$125 million on the Corporation's existing credit facility.

On August 1, 2007, Fortis Properties purchased the Delta Regina, comprised of the 274-room Delta Regina hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan, for an aggregate cash purchase price of approximately \$50 million.

Key Trends and Risks: Terasen improved the risk profile of Fortis by providing the Corporation with a more economically diverse portfolio of assets and earnings. The expansion into natural gas added a new business segment, doubled the regulated rate base of Fortis and was complementary to the Corporation's proven core competencies in managing regulated electric distribution utilities. The distribution franchises of the Terasen Gas companies have a well-diversified, mature, principally residential customer base and operate in a service territory that has experienced steady economic growth and includes substantially all of the service territory of FortisBC. The expansion into natural gas distribution provides Fortis with a platform for future growth in the regulated natural gas business in Canada and the United States.

A large proportion of the businesses of Fortis serve the economies of western Canada, which have been growing faster than other regions of Canada. As at December 31, 2008, regulated utility assets comprised 92 per cent of total assets (December 31, 2007 – 92 per cent) and regulated utility assets in Canada comprised 82 per cent of total assets (December 31, 2007 – 84 per cent).

Declining long-term interest rates in Canada since 2005 have negatively impacted the formula-based allowed rate of return on common shareholders' equity ("ROE") used to set customer rates at each of the Corporation's four largest regulated utilities. The chart below highlights the trend in the regulator-allowed ROEs at each of the Corporation's four largest regulated utilities.

Regulator-Allowed ROE

(%)	2005	2006	2007	2008	2009
Terasen Gas Inc.	9.03	8.80	8.37	8.62	8.47
FortisAlberta	9.50	8.93	8.51	8.75	8.51 ⁽¹⁾
FortisBC	9.43	9.20	8.77	9.02	8.87
Newfoundland Power	9.24	9.24	8.60	8.95	8.95

⁽¹⁾ Interim ROE pending outcome of regulatory proceeding

The impact on the Corporation's consolidated earnings of lower allowed ROEs has been more than offset by earnings derived from increased rate bases and energy sales and the realization of operating cost efficiencies.

Management Discussion and Analysis

Economic growth in the province of Alberta has been robust in the past few years translating into strong customer, energy sales and rate base growth at FortisAlberta. The rate of growth may decrease in 2009 due to the current global economic environment and depressed world oil prices. FortisAlberta's service territory includes the environs of Calgary and Edmonton as well as the corridor between these cities. A healthy British Columbia provincial economy and population growth in the Okanagan region have favourably impacted customer and sales growth at FortisBC and the Terasen Gas companies over the past few years. Sales growth in 2008 at FortisBC was tempered due to decreased activity in the forestry sector. Organic earnings growth from the Corporation's regulated utilities in Canada is expected to be primarily driven by rate base growth at FortisAlberta, FortisBC and the Terasen Gas companies. The Corporation's other Canadian regulated electric utilities, Newfoundland Power, Maritime Electric and FortisOntario, are expected to generate slower earnings' growth.

Regulated assets in the Caribbean region, as a percentage of the Corporation's total regulated assets, were 10 per cent at December 31, 2008 (December 31, 2007 – 8 per cent). The regulated rate of return on rate base assets ("ROA") achieved in the Caribbean is higher than that achieved in Canada. The higher return is correlated with increased operating risks associated with local economic and political factors and weather conditions. However, the allowed ROAs at Caribbean Utilities and Belize Electricity were lowered in 2008 due to the negotiation of new licences at Caribbean Utilities and the impact of a regulatory rate decision at Belize Electricity. Economic growth has been strong in the Corporation's service territories in the Caribbean, positively impacting customer and sales growth. The rate of growth is expected to be lower in 2009 due to the impact of the global economic downturn. The Corporation's operations in the Caribbean are exposed to hurricane risk. Fortis uses external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.

The key business risk to Fortis is regulatory risk. Except for the Terasen Gas companies and FortisBC, which have the same regulator, the Corporation's other utilities are regulated by different regulatory authorities. Relationships with the regulatory authorities are managed at the local utility level and such relationships have generally been positive. However, the relationship of Belize Electricity with its regulator became tenuous in 2008 when the regulator issued a decision disallowing previously incurred fuel and purchased power costs and lowering the regulated ROA. The decision has negatively impacted Belize Electricity's financial health. Although the receipt of an adverse regulatory decision may materially affect the ability of any utility to recover the cost of providing its services and achieving a reasonable rate of return, the impact on the Corporation as a whole is lessened due to the geographic and regulatory diversity of its operations. The total assets of Belize Electricity comprise approximately 2 per cent of the Corporation's total assets.

In Canada, regulator-approved negotiated settlement agreements were reached at FortisAlberta and FortisBC for 2008 and 2009 electricity rates and at Newfoundland Power for 2008 electricity rates. Achieving regulator-approved negotiated settlement agreements eliminates the cost of full-scale public hearing processes. Customer rates at Newfoundland Power and the Terasen Gas companies have also been set for 2009.

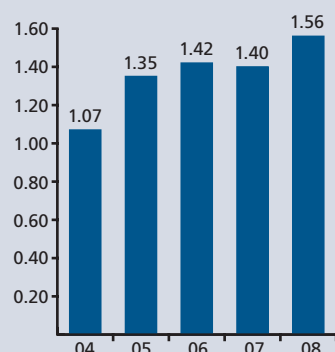
The Corporation's regulated gas and electric utilities require continual access to long-term capital to fund investments in infrastructure necessary to provide service to customers. Long-term capital required to carry out the subsidiary capital expenditure programs is mostly obtained at the regulated utility level. The subsidiaries issue debt mostly at terms ranging between 10 years and 30 years. As at December 31, 2008, approximately 84 per cent of the Corporation's consolidated long-term debt and capital lease obligations had maturities beyond five years. To help ensure uninterrupted access to capital and sufficient liquidity to fund capital programs and working capital requirements, the Corporation and its subsidiaries have \$2.2 billion in credit facilities of which approximately \$1.5 billion was available as at December 31, 2008. During 2008, Fortis and its subsidiaries issued almost \$1.2 billion in equity and long-term debt. With strong credit ratings and conservative capital structures, the Corporation and its subsidiaries expect to continue to have reasonable access to long-term capital in 2009.

Common share dividend payments increased to \$1.00 per common share in 2008. Effective for the first quarter of 2009, a 4 per cent increase in the quarterly common share dividend to 26 cents from 25 cents extends the Corporation's record of annual common share dividend increases to 36 consecutive years, the longest record of any public corporation in Canada.

For a complete discussion of the Corporation's business risks, including regulatory risk and the impact on the Corporation and its subsidiaries of recent economic conditions, refer to the "Regulatory Highlights", "Business Risk Management" and "Outlook" sections of this MD&A.

Management Discussion and Analysis

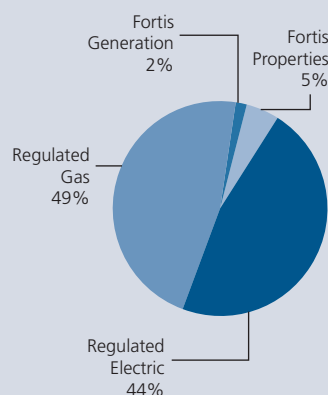
Basic Earnings per Common Share (\$)



Net Earnings Applicable to Common Shares and Earnings per Common Share: Fortis achieved net earnings applicable to common shares of \$245 million in 2008, a 26.9 per cent increase over earnings of \$193 million in the previous year. The increase in earnings was primarily due to earnings' contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007, rate base growth and higher allowed ROEs at the Corporation's Canadian regulated utilities, and increased non-regulated hydroelectric production due to higher rainfall. The increase was tempered by a one-time \$13 million loss related to a June 2008 regulatory rate decision at Belize Electricity and lower corporate tax recoveries at FortisAlberta. Results for 2008 also reflected a \$7.5 million tax reduction (\$5.5 million at the Terasen Gas companies and \$2 million at Terasen Inc.) associated with the settlement of historical corporate tax matters at Terasen. Results for 2007 reflected a \$7 million after-tax gain on the sale of surplus land at TGI.

Basic earnings per common share were \$1.56 in 2008, an 11.4 per cent increase over \$1.40 in the previous year. The increase was primarily due to growth in earnings associated with the Terasen Gas companies and increased non-regulated hydroelectric production. Basic earnings per common share in 2007 were diluted by the common shares issued to fund the acquisition of Terasen and by the seasonality of earnings at the Terasen Gas companies.

Revenue⁽¹⁾
(year ended December 31, 2008)



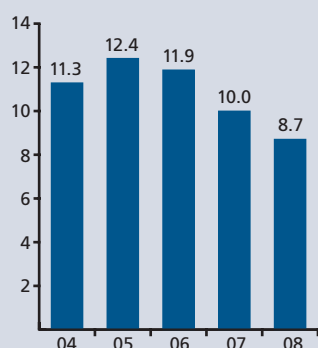
⁽¹⁾ Excludes Corporate and Other

Revenue: Revenue increased 43.6 per cent to approximately \$3.9 billion from approximately \$2.7 billion in 2007. The increase was driven by contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007. The remainder of the increase was mainly the result of customer rate increases, which included the impact of higher allowed ROEs for 2008 and the flow through to customers of higher energy supply costs; two additional months of contribution from Caribbean Utilities due to a change in the utility's fiscal year end; and customer growth.

Return on Average Common Shareholders' Equity: Return on average common shareholders' equity was 8.7 per cent in 2008 compared to 10.0 per cent in 2007. The decline largely related to higher average common shareholders' equity associated with the May 2007 acquisition of Terasen.

Cash Flow from Operating Activities: Cash flow from operating activities, after working capital adjustments, was \$663 million in 2008, 77.7 per cent higher than \$373 million in the previous year. The increase primarily reflected a full year of contributions from the Terasen Gas companies in 2008.

Return on Average Common Shareholders' Equity (%)



2008 Capital Expenditures: During 2008, consolidated capital expenditures, before customer contributions ("gross capital expenditures"), were \$904 million, including capital expenditures of approximately \$220 million at the Terasen Gas companies. Total capital investment at FortisAlberta and FortisBC during 2008 was approximately \$419 million, representing approximately 46 per cent of total gross capital expenditures. Much of the capital investment was driven by customer growth and the need to enhance the reliability of electricity systems.

Management Discussion and Analysis

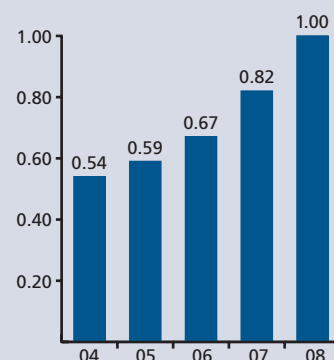
Dividends: Dividends paid per common share increased to \$1.00 in 2008, up 22.0 per cent from 82 cents in 2007. Commencing with the first quarter dividend paid on March 1, 2009, Fortis increased its quarterly common share dividend 4 per cent to 26 cents from 25 cents. The Corporation's dividend payout ratio was 64.1 per cent in 2008 compared to 58.6 per cent in 2007.

In December 2008, the Corporation amended and restated its Dividend Reinvestment and Share Purchase Plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

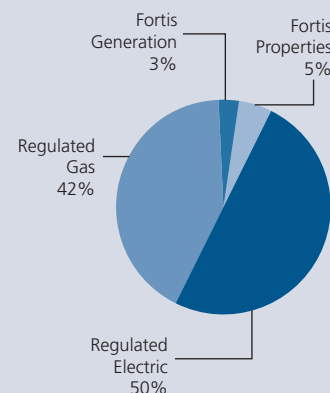
Asset Growth: Total assets increased 8.8 per cent to approximately \$11.2 billion at the end of 2008 compared to approximately \$10.3 billion at the end of 2007. The increase was primarily due to the Corporation's continued investment in energy systems at FortisAlberta, FortisBC and the Terasen Gas companies, combined with the impact of foreign exchange associated with translation of foreign currency-denominated assets.

Financings: During 2008, Fortis and its utilities raised almost \$1.2 billion of capital from a combination of preference share, common share and long-term debt issues. In the second quarter of 2008, the Corporation publicly issued 9.2 million 5.25% Five-Year Fixed-Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") for gross proceeds of approximately \$230 million (\$223 million net of costs). The net proceeds were used to repay \$170 million under the Corporation's committed credit facility, fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately \$300 million (\$287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire \$200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes. At the subsidiary level, TGI issued \$250 million of 30-year 6.05% unsecured debentures in February; FortisAlberta issued \$100 million of 30-year 5.85% unsecured debentures in April; Maritime Electric issued \$60 million of 30-year 6.05% secured first mortgage bonds in April; and TGI issued \$250 million of 30-year 5.80% unsecured debentures in May. Proceeds from the long-term debt issues at the utilities were primarily used to repay indebtedness under credit facilities incurred in support of capital spending. Additionally, partial proceeds from the issuance of the \$250 million unsecured debentures by TGI were used to refinance \$188 million of debt that matured in May 2008.

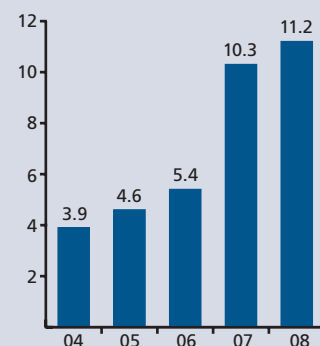
Dividends Paid per Common Share (\$)



Total Assets (as at December 31, 2008)



Total Assets (\$ billions) (as at December 31)



Management Discussion and Analysis

Segmented Results of Operations

The segmented results of the Corporation are outlined below.

Segmented Net Earnings

Years Ended December 31

(\$ millions)

	2008	2007	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies ⁽¹⁾	118	50	68
Regulated Electric Utilities – Canadian			
FortisAlberta	46	48	(2)
FortisBC	34	31	3
Newfoundland Power	32	30	2
Other Canadian	14	16	(2)
	126	125	1
Regulated Electric Utilities – Caribbean ⁽²⁾	17	31	(14)
Non-Regulated – Fortis Generation	30	24	6
Non-Regulated – Fortis Properties ⁽³⁾	23	24	(1)
Corporate and Other	(69)	(61)	(8)
Net Earnings Applicable to Common Shares	245	193	52

⁽¹⁾ Financial results are reported from May 17, 2007, the date of acquisition.

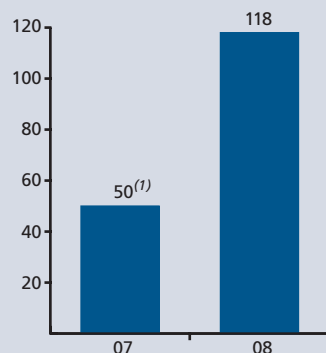
⁽²⁾ Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. Going forward, this change in fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.

⁽³⁾ Includes the results of the Fairmont Newfoundland hotel from November 2008, the date of acquisition

REGULATED UTILITIES

The Corporation's primary business is regulated utilities. In 2008, regulated earnings in Canada and the Caribbean represented approximately 83 per cent (2007 – 81 per cent) of the Corporation's earnings from its operating segments (excluding the Corporate and Other segment). Total regulated assets represented 92 per cent of the Corporation's total assets as at December 31, 2008 (December 31, 2007 – 92 per cent).

Regulated Gas Utilities – Canadian Earnings (\$ millions)



⁽¹⁾ Earnings are from May 17, 2007

Regulated Gas Utilities – Canadian

Regulated Gas Utilities – Canadian earnings for 2008 were \$118 million (2007 – \$50 million), which represented approximately 45 per cent of the Corporation's total regulated earnings (2007 – 24 per cent). Earnings for 2007 were from May 17, 2007, the date of acquisition of the Regulated Gas Utilities – Canadian. Regulated Gas Utilities – Canadian assets were approximately \$4.6 billion as at December 31, 2008 (December 31, 2007 – \$4.4 billion), which represented approximately 45 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 47 per cent).

Terasen Gas Companies

Financial Highlights

Years Ended December 31	2008	2007 ⁽¹⁾	Variance
Gas Volumes (TJ)	221,122	118,309	102,813
(\$ millions)			
Revenue	1,902	905	997
Energy Supply Costs	1,268	559	709
Operating Expenses	253	150	103
Amortization	97	58	39
Finance Charges	129	80	49
Gain on Sale of Property	–	(8)	8
Corporate Taxes	37	16	21
Earnings	118	50	68

⁽¹⁾ Results are reported from May 17, 2007, the date of acquisition.

Management Discussion and Analysis

Gas Volumes: Gas volumes were 221,122 TJ for 2008 compared to 220,977 TJ reported by the Terasen Gas companies for the full year in 2007. Increased sales volumes to residential customers, as a result of increased consumption due to cooler weather year over year, and higher sales volumes to customers under fixed price contracts, were largely offset by lower transportation volumes to customers sourcing their own gas supplies.

The Terasen Gas companies earn approximately the same margin regardless of whether a customer contracts for the purchase of natural gas or contracts for the transportation of natural gas only.

As a result of the operation of British Columbia Utilities Commission ("BCUC")-approved regulatory deferral mechanisms, changes in consumption levels and energy supply costs from those forecasted to set gas distribution rates do not materially affect earnings.

During 2008, net customer additions at TGI and TGVI totalled approximately 12,800, bringing the total customer count at TGI and TGVI to approximately 929,000 at December 31, 2008. During 2007, net customer additions at TGI and TGVI totalled approximately 13,900. Net customer additions in 2008 were lower than expected, reflecting weakening housing and construction markets and growth in multi-family housing where natural gas use is less prevalent compared to single-family housing.

Revenue: Revenue was approximately \$1.9 billion for 2008 compared to \$905 million for the partial year in 2007. In addition to the impact of revenue contribution for the full year in 2008, revenue also increased year over year due to: (i) the higher commodity cost of gas charged to customers; (ii) increased residential customer consumption; and (iii) an increase in gas distribution rates, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE for TGI and TGVI to 8.62 per cent and 9.32 per cent, respectively, from 8.37 per cent and 9.07 per cent, respectively.

Earnings: Earnings were \$118 million for 2008 compared to \$50 million for the partial year in 2007. Earnings for 2007 were favourably impacted by a \$7 million after-tax gain on the sale of surplus land. Earnings for 2008 included an approximate \$5.5 million tax reduction associated with the settlement of historical corporate tax matters. During the third quarter of 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency ("CRA") related to amounts owing as a result of amended Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain interprovincial Canadian tax structures.

In addition to earnings' contribution for a full year in 2008 and the one-time tax reduction described above, earnings for 2008 were favourably impacted by the increase in gas distribution rates, effective January 1, 2008, reflecting a higher allowed ROE, partially offset by: (i) higher operating expenses driven by increased labour costs; (ii) higher amortization costs associated with the continued investment in capital assets; and (iii) higher finance charges reflective of higher borrowing rates.

Seasonality materially impacts the earnings of the Terasen Gas companies as a major portion of the gas distributed is used for space heating. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

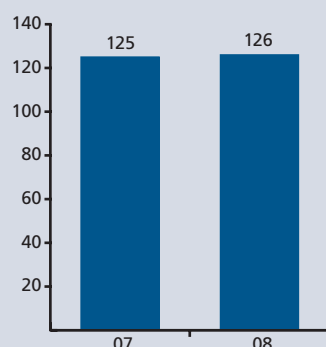
Outlook: TGI's allowed ROE for 2009 has been set at 8.47 per cent, down from 8.62 per cent in 2008. TGVI's allowed ROE for 2009 has been set at 9.17 per cent, down from 9.32 per cent in 2008. TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the regulator in the second quarter of 2009.

In February 2009, TGI issued \$100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay \$60 million of unsecured debentures that mature in June 2009.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to the Terasen Gas companies is provided under the heading "Regulatory Highlights". A summary of the forecast gross capital expenditures for 2009 for the Terasen Gas companies is provided under the heading "Liquidity and Capital Resources – Capital Program".

Management Discussion and Analysis

Regulated Electric Utilities – Canadian Earnings (\$ millions)



Regulated Electric Utilities – Canadian

Regulated Electric Utilities – Canadian earnings for 2008 were \$126 million (2007 – \$125 million), which represented approximately 48 per cent of the Corporation's total regulated earnings (2007 – 61 per cent). Regulated Electric Utilities – Canadian assets were approximately \$4.6 billion as at December 31, 2008 (December 31, 2007 – \$4.2 billion), which represented approximately 45 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 45 per cent).

FortisAlberta

Financial Highlights

Years Ended December 31	2008	2007	Variance
Energy Deliveries (GWh)	15,722	15,378	344
(\$ millions)			
Revenue	300	270	30
Operating Expenses	130	122	8
Amortization	85	75	10
Finance Charges	42	36	6
Corporate Tax Recovery	(3)	(11)	8
Earnings	46	48	(2)

Energy Deliveries: Energy deliveries at FortisAlberta increased 344 gigawatt hours ("GWh"), or 2.2 per cent, year over year, mainly due to customer growth. During 2008, the number of customers at FortisAlberta increased by approximately 12,700, bringing the total number of customers at FortisAlberta to approximately 461,000 at the end of 2008.

As a significant portion of the Company's distribution revenue is derived from fixed or largely fixed billing determinants, changes in energy deliveries are not directly correlated with changes in revenue.

Revenue: Revenue was \$30 million higher than the previous year, mainly due to: (i) a 6.8 per cent increase in customer distribution rates, effective January 1, 2008; (ii) the impact of customer and load growth; (iii) the accrual for collection in future customer distribution rates of the increase in the 2008 allowed ROE to 8.75 per cent from 8.51 per cent, effective January 1, 2008; and (iv) increased franchise fee revenue.

Earnings: Earnings were \$2 million lower than the previous year, driven by lower future income tax recoveries primarily associated with the regulator-approved Alberta Electric System Operator ("AESO") charges deferral account. Additionally, higher revenue was partially offset by: (i) higher operating expenses due to increased contracted manpower costs, higher labour and employee-benefit costs associated with increased salaries and number of employees, and higher general operating expenses; (ii) increased amortization costs associated with continued investment in capital assets and higher amortization rates provided for in the 2008/2009 Negotiated Settlement Agreement ("NSA"); and (iii) increased finance charges driven by higher debt levels in support of the Company's significant capital expenditure program.

FortisAlberta's AESO charges deferral account captures variances between amounts charged by the AESO to FortisAlberta for transmission tariffs and amounts collected by FortisAlberta from customers through the transmission tariff component of basic customer rates. Subject to regulatory approval, amounts charged by the AESO in excess of amounts collected from customers are deferred as a regulatory asset for future recovery from customers, and amounts collected from customers in excess of amounts charged are deferred as a regulatory liability for future refund to customers. Generally, there is a two-year lag between the deferral of amounts in the AESO charges deferral account and their collection from, or refund to, customers in rates.

FortisAlberta records income taxes on the cash taxes payable method, as approved by its regulator, except for certain deferral accounts, including the AESO charges deferral account, whereby income taxes are recorded using the liability method. During the third quarter of 2008, FortisAlberta identified that taxable income from operations, before considering impacts associated with the AESO charges deferral account, could be fully offset by utilizing capital cost allowance deductions. Then, by applying the tax deductions related to transmission tariff payments made to the AESO, a tax loss carryforward could be created and a future income tax recovery could be recorded. Under the liability method of recording income taxes, a future income tax asset associated with the tax loss carryforward may be recorded when there is certainty of recovery. The transmission tariff payments made to the AESO are

Management Discussion and Analysis

recoverable from customers in the future; therefore, a future income tax asset and future income tax recovery were recorded in each of the third and fourth quarters of 2008, which offset the future income tax liability and future income tax expense created by the AESO charges deferral as it was incurred.

Prior to the third quarter of 2008, FortisAlberta was not deducting transmission tariff payments made to the AESO to create tax loss carryforwards and was not recording the associated future income tax recoveries. This accounting treatment, in effect, resulted in a two-year lag of recording the future income tax impacts between the payments of transmission tariff amounts to the AESO and the timing of their collection from customers. Going forward, fluctuations in corporate income taxes associated with the operation of the AESO charges deferral account are not expected to occur.

During 2007, net future income tax recoveries of approximately \$9 million were recorded, primarily due to the sale of amounts deferred to the AESO charges deferral account. In September 2007, the 2006 deferred AESO charges receivable balance of \$28 million and, in December 2007, approximately \$38 million of the 2007 deferred AESO charges receivable balance, were sold to a Canadian chartered bank and, as a result, the proceeds were recognized in 2007.

Outlook: During 2008, the Alberta Utilities Commission ("AUC") ruled that a 2009 Generic Cost of Capital Proceeding to review ROE levels, adjustment mechanisms and utility capital structures would be appropriate for all gas, electric and pipeline utilities in Alberta that it regulates. As directed by the AUC, FortisAlberta is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, down from the allowed ROE of 8.75 per cent in 2008, pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding.

FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.

In December 2008, FortisAlberta filed a short-form base shelf prospectus for the issuance of up to \$350 million in debentures. In February 2009, FortisAlberta issued \$100 million of 30-year 7.06% unsecured debentures under the shelf prospectus. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisAlberta is provided under the heading "Regulatory Highlights". A summary of the forecast gross capital expenditures for 2009 for FortisAlberta is provided under the heading "Liquidity and Capital Resources – Capital Program".

FortisBC

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales (GWh)	3,087	3,091	(4)
(\$ millions)			
Revenue	237	229	8
Energy Supply Costs	68	67	1
Operating Expenses	67	69	(2)
Amortization	34	31	3
Finance Charges	28	26	2
Corporate Taxes	6	5	1
Earnings	34	31	3

Electricity Sales: Electricity sales at FortisBC decreased 4 GWh, or 0.1 per cent, year over year due to reduced industrial customer loads as a result of a general slowdown in the forestry sector, partially offset by the impact of residential, general service and wholesale customer growth.

Revenue: Revenue was \$8 million higher than the previous year, driven by the impact of: (i) a 2.9 per cent increase in electricity rates, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE to 9.02 per cent from 8.77 per cent; (ii) a 0.8 per cent increase in electricity rates, effective May 1, 2008, as a result of the flow through to customers of increased purchased power costs from BC Hydro; and (iii) a shift in sales mix from lower-rate to higher-rate customer classes. The increase was partially offset by lower revenue contributions from non-regulated operating, maintenance and management services and lower electricity sales.

Management Discussion and Analysis

Earnings: Earnings were \$3 million higher than the previous year. The increase was primarily due to the 2.9 per cent increase in electricity rates, partially offset by higher amortization costs and finance charges related to the Company's significant capital expenditure program.

Operating expenses were \$2 million lower than the previous year, mainly due to lower operating expenses associated with non-regulated operating, maintenance and management services, partially offset by the impact of higher labour costs and general inflationary cost increases year over year.

Outlook: FortisBC's allowed ROE for 2009 has been set at 8.87 per cent, down from 9.02 per cent in 2008. In December 2008, FortisBC received regulatory approval of the Company's 2009 Revenue Requirements Application, resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The approval of the 2009 Revenue Requirements Application also included an extension of the performance-based rate-setting ("PBR") mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to FortisBC is provided under the heading "Regulatory Highlights". A summary of the forecast gross capital expenditures for 2009 for FortisBC is provided under the heading "Liquidity and Capital Resources – Capital Program".

Newfoundland Power

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales (GWh)	5,208	5,093	115
(\$ millions)			
Revenue	517	491	26
Energy Supply Costs	337	327	10
Operating Expenses	50	53	(3)
Amortization	45	34	11
Finance Charges	33	34	(1)
Corporate Taxes	19	12	7
Non-Controlling Interest	1	1	–
Earnings	32	30	2

Electricity Sales: Electricity sales at Newfoundland Power increased 115 GWh, or 2.3 per cent, year over year, primarily due to the combined impact of customer growth and higher average consumption.

Revenue: Revenue in 2008 was \$26 million higher than the previous year. The increase was driven by an average increase in customer rates of 2.8 per cent, effective January 1, 2008, which included the impact of an increase in the 2008 allowed ROE to 8.95 per cent from 8.60 per cent, and electricity sales growth. The increase in revenue also reflected higher amortization of regulatory liabilities in accordance with prescribed regulatory orders.

Earnings: Earnings were \$2 million higher than the previous year, driven by the average 2.8 per cent increase in customer rates, effective January 1, 2008, lower operating expenses driven by the timing of expenses and lower maintenance and pension costs, and lower finance charges. Finance charges decreased due to the refinancing of maturing debt in August 2007 at lower rates.

Amortization costs were higher year over year due to the regulator-approved recovery in customer rates, effective January 1, 2008, of previously deferred amortization costs.

Corporate tax expense increased year over year as a result of higher earnings before corporate taxes, combined with a higher effective corporate income tax rate, which was driven by decreased deductions taken for tax purposes compared to accounting purposes.

Outlook: Newfoundland Power's allowed ROE for 2009 has been set at 8.95 per cent, unchanged from 2008; consequently, there has been no change in base customer rates for 2009.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Newfoundland Power is provided under the heading "Regulatory Highlights". A summary of Newfoundland Power's forecast gross capital expenditures for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Management Discussion and Analysis

Other Canadian Electric Utilities⁽¹⁾

Financial Highlights

Years Ended December 31	2008	2007	Variance
Electricity Sales (GWh)	2,182	2,209	(27)
(\$ millions)			
Revenue	262	263	(1)
Energy Supply Costs	177	174	3
Operating Expenses	28	29	(1)
Amortization	18	17	1
Finance Charges	18	17	1
Corporate Taxes	7	10	(3)
Earnings	14	16	(2)

⁽¹⁾ Includes Maritime Electric and FortisOntario

Electricity Sales: Electricity sales at Other Canadian Electric Utilities decreased 27 GWh, or 1.2 per cent, year over year. The decrease was driven by the impact of the shut down of operations of certain industrial customers in Ontario and lower average consumption in Ontario.

Revenue: Revenue was \$1 million lower than the previous year. During 2007, FortisOntario received a one-time refund of approximately \$3 million (\$2 million after-tax) from Niagara Mohawk Power Corporation ("NIMO") associated with cross-border transmission interconnection agreements. In April 2008, the US Federal Energy Regulatory Commission issued an order stating that the refund should not have been ordered. In May 2008, FortisOntario repaid the refunded amounts to NIMO.

Excluding the impact of the receipt of the \$3 million refund in 2007 and its subsequent repayment in 2008, revenue increased \$5 million year over year. The increase was primarily due to: (i) the flow through to customers of higher energy supply costs at FortisOntario; (ii) a 1.8 per cent increase in basic electricity rates at Maritime Electric, effective April 1, 2008; and (iii) an average 1.1 per cent increase in basic electricity distribution rates at FortisOntario, effective May 1, 2008, partially offset by the impact of lower electricity sales.

Earnings: Earnings were \$2 million lower than the previous year. Excluding the impact of the receipt of the refund in 2007 and its subsequent repayment in 2008, earnings were \$2 million higher year over year. The increase was driven by higher basic electricity rates, lower operating expenses and lower effective corporate taxes, partially offset by the impact of lower electricity sales and higher finance charges associated with increased borrowings. Operating expenses in 2007 included costs associated with an early retirement program at FortisOntario.

In October 2008, FortisOntario entered into a definitive agreement to acquire a 10 per cent strategic ownership in the electricity distribution business of Grimsby Power Inc. for a cash payment of approximately \$1 million plus the provision of services to integrate Grimsby Power Inc.'s customer information system with FortisOntario's system. Grimsby Power Inc. serves approximately 10,000 distribution customers in the western area of the Niagara region. The transaction has been approved by the Ontario Energy Board ("OEB") and is pending approval from the Ontario Ministry of Finance.

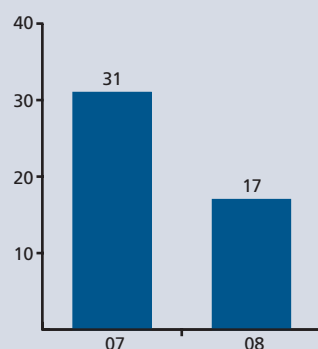
Outlook: In March 2009, Maritime Electric received regulatory approval of its 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The regulator also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.

Canadian Niagara Power filed a 2009 Cost of Service Application in August 2008 requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The Company expects a decision on the application to be received in April 2009.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Other Canadian Electric Utilities is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Other Canadian Electric Utilities for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

Management Discussion and Analysis

Regulated Electric Utilities – Caribbean Earnings (\$ millions)



Regulated Electric Utilities – Caribbean

Earnings' contribution from Regulated Electric Utilities – Caribbean for 2008 was \$17 million (2007 – \$31 million), which represented approximately 7 per cent of the Corporation's total regulated earnings (2007 – 15 per cent). Regulated Electric Utilities – Caribbean assets were approximately \$1.0 billion as at December 31, 2008 (December 31, 2007 – \$0.8 billion), which represented approximately 10 per cent of the Corporation's total regulated assets as at December 31, 2008 (December 31, 2007 – 8 per cent).

Regulated Electric Utilities – Caribbean⁽¹⁾

Financial Highlights

Years Ended December 31	2008 ⁽²⁾	2007	Variance
Average US:CDN Exchange Rate⁽³⁾	1.08	1.07	0.01
Electricity Sales (GWh)	1,199	1,054	145
(\$ millions)			
Revenue	408	307	101
Energy Supply Costs	273 ⁽⁴⁾	169	104
Operating Expenses	55	49 ⁽⁵⁾	6
Amortization	36	28	8
Finance Charges	16	15	1
Corporate Taxes	2	2	–
Non-Controlling Interest	9	13	(4)
Earnings	17	31	(14)

⁽¹⁾ Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos

⁽²⁾ Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, Caribbean Utilities' financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008.

⁽³⁾ The reporting currency of Belize Electricity is the Belizean dollar, which is pegged to the US dollar at BZ\$2.00 = US\$1.00. The reporting currency of Caribbean Utilities and Fortis Turks and Caicos is the US dollar.

⁽⁴⁾ Energy supply costs during 2008 included an \$18 million (BZ\$36 million) charge as a result of a regulatory rate decision by the Public Utilities Commission of Belize in June 2008.

⁽⁵⁾ Operating expenses during 2007 included a \$4.4 million (US\$3.7 million) charge on the disposal of steam-turbine assets at Caribbean Utilities.

Electricity Sales: Electricity sales at Regulated Electric Utilities – Caribbean increased 145 GWh, or 13.8 per cent, year over year, driven by two additional months of contribution from Caribbean Utilities related to a change in the utility's fiscal year end, and customer and general economic growth. The increase was tempered by the loss of electricity sales at Fortis Turks and Caicos as a result of Hurricane Ike, including the delayed reopening for the fall tourist season of several large hotels on the Turks and Caicos Islands. Hurricane Ike was a Category 4 hurricane which struck the Turks and Caicos Islands in early September 2008. The increase was also tempered by the impact on electricity sales associated with the reduction in tourism activities related to global economic conditions towards the end of 2008.

Excluding the two additional months of contribution from Caribbean Utilities, electricity sales increased 6.0 per cent year over year. Electricity sales increased 8.7 per cent in 2007 compared to 2006.

Revenue: Revenue increased \$101 million over the previous year; however, annual revenue for 2008 included the two additional months of contribution from Caribbean Utilities and an approximate \$6 million favourable impact of foreign currency translation due to the weakening of the Canadian dollar against the US dollar year over year. Excluding the two additional months of contribution from Caribbean Utilities and the favourable impact of foreign currency translation, revenue increased year over year primarily due to: (i) the full flow through of higher fuel and oil costs to customers at Caribbean Utilities under the terms of the Company's new T&D licence; (ii) electricity sales growth; and (iii) an increase in the cost of power component of the average electricity rate at Belize Electricity, effective July 1, 2008. Partially offsetting the above factors were: (i) a decrease in the value-added delivery ("VAD") component of the average electricity rate at Belize Electricity, effective July 1, 2008; (ii) a 3.25 per cent reduction in basic electricity rates and the elimination of the hurricane cost recovery surcharge ("CRS") at Caribbean Utilities, effective January 1, 2008, under the terms of the Company's new T&D licence; and (iii) revenue loss of approximately \$2 million at Fortis Turks and Caicos due to Hurricane Ike.

Management Discussion and Analysis

Earnings: Earnings' contribution was \$14 million lower than the previous year. Earnings' contribution in 2008 was reduced by \$13 million, representing the Corporation's approximate 70 per cent share of \$18 million (BZ\$36 million) of previously incurred fuel and purchased power costs at Belize Electricity disallowed by the regulator. Earnings' contribution in 2007 was reduced by approximately \$2 million, representing the Corporation's share of a charge on the disposal of steam-turbine assets at Caribbean Utilities.

Excluding the one-time items in 2008 and 2007, as described above, earnings were \$3 million lower year over year. The impact of electricity sales growth, \$1 million of additional earnings' contribution from Caribbean Utilities, and the favourable impact on energy supply costs associated with the movement in deferred fuel costs at Caribbean Utilities was more than offset by: (i) the impact of the 3.25 per cent reduction in basic electricity rates and the elimination of the hurricane CRS at Caribbean Utilities; (ii) the reduction in the VAD component of the average electricity rate at Belize Electricity; (iii) revenue loss of approximately \$2 million at Fortis Turks and Caicos due to Hurricane Ike; and (iv) increased operating expenses and amortization costs.

A large portion of the costs of reconnecting customers and restoring electricity service at Fortis Turks and Caicos as a result of Hurricane Ike was capital in nature and, therefore, did not affect earnings.

Excluding the impact of foreign currency translation and the charge on the disposal of steam-turbine assets in 2007, operating expenses increased mainly due to the impact of hiring additional employees and increased general and administrative expenses at Fortis Turks and Caicos, and the timing of maintenance activities. Amortization costs increased as a result of continued investment in capital assets.

In addition to the \$18 million charge described above, Belize Electricity's targeted allowed ROA was reduced to 10 per cent from 12 per cent, effective July 1, 2008, which was reflected through a reduction in the VAD component of the average electricity rate.

In April 2008, Caribbean Utilities and the Government of the Cayman Islands entered into a new exclusive 20-year T&D licence and a new non-exclusive 21.5-year generation licence. Under the new T&D licence, customer rates are being set using an initial targeted ROA of 10 per cent, down from 15 per cent as allowed under the previous licence, which was reflected through the reduction in basic electricity rates, effective January 1, 2008.

Outlook: Growth in annual electricity sales at the Corporation's regulated utilities in the Caribbean for 2009 is expected to be approximately 4 per cent, reflecting the anticipated continued global economic downturn that is negatively affecting activity in the tourism, oil and related industries in the Caribbean region.

A discussion of the nature of regulation and material regulatory decisions and applications pertaining to Regulated Electric Utilities – Caribbean is provided under the heading "Regulatory Highlights". A summary of forecast gross capital expenditures for the Regulated Electric Utilities – Caribbean segment for 2009 is provided under the heading "Liquidity and Capital Resources – Capital Program".

NON-REGULATED

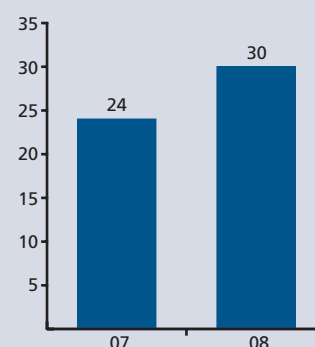
Non-Regulated – Fortis Generation⁽¹⁾

Financial Highlights

Years Ended December 31	2008	2007	Variance
Energy Sales (GWh)	1,217	1,122	95
(\$ millions)			
Revenue	82	75	7
Energy Supply Costs	7	8	(1)
Operating Expenses	14	14	–
Amortization	10	10	–
Finance Charges	8	10	(2)
Corporate Taxes	10	8	2
Non-Controlling Interest	3	1	2
Earnings	30	24	6

⁽¹⁾ Includes the operations of non-regulated generation assets in Belize, Ontario, central Newfoundland, British Columbia and Upper New York State.

Non-Regulated – Fortis Generation Earnings (\$ millions)



Management Discussion and Analysis

Energy Sales: Energy sales from Non-Regulated – Fortis Generation increased 95 GWh, or 8.5 per cent, year over year, driven by higher production in central Newfoundland, Belize and Upper New York State. Higher production was mainly the result of higher rainfall.

Revenue: Revenue was \$7 million higher year over year. Factors increasing revenue were: (i) higher production; (ii) increased average wholesale energy prices per megawatt hour (“MWh”) in Ontario, which were \$48.83 for 2008 compared to \$47.81 for 2007; and (iii) increased average wholesale energy prices per MWh in Upper New York State, which were US\$71.00 for 2008 compared to US\$60.73 for 2007.

Earnings: Earnings were \$6 million higher year over year, reflecting increased production and lower finance charges driven by the refinancing, in November 2007, of higher-cost external debt with lower-cost inter-company borrowings. Higher average wholesale energy prices also contributed to the increase in earnings year over year.

Outlook: Construction continued in 2008 on the US\$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize. The facility is expected to come into service at the beginning of 2010. The earnings’ contribution from the Vaca facility, combined with the Corporation’s planned consolidated capital program over the next couple of years, are expected to more than offset the loss of earnings upon the expiration, in April 2009, of the Niagara Exchange Agreement associated with the Rankine hydroelectric generating station in Ontario.

Further information on the Vaca hydroelectric generating facility and a summary of forecast non-regulated utility capital expenditures for 2009 is provided under the heading “Liquidity and Capital Resources – Capital Program”.

Non-Regulated – Fortis Properties

Financial Highlights

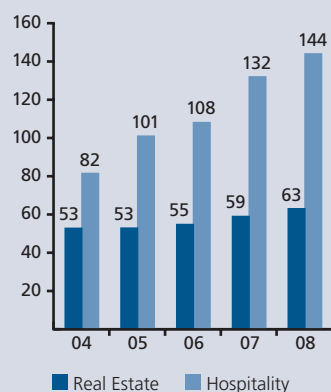
Years Ended December 31

(\$ millions)

	2008	2007	Variance
Hospitality Revenue	144	132	12
Real Estate Revenue	63	59	4
Total Revenue	207	191	16
Operating Expenses	135	123	12
Amortization	15	14	1
Finance Charges	24	24	–
Corporate Taxes	10	6	4
Earnings	23	24	(1)

Fortis Properties

Revenue (\$ millions)



Revenue: Hospitality revenue was \$12 million higher than the previous year, reflecting revenue contribution from the Delta Regina, acquired in August 2007, and the Fairmont Newfoundland hotel, which was acquired for approximately \$22 million in November 2008 and rebranded the Sheraton Hotel Newfoundland in January 2009. Hospitality revenue also increased year over year due to improved performance at the Company’s operations in Atlantic Canada.

Revenue per available room (“REVPAR”) for 2008 was \$80.39 compared to \$79.31 for 2007. The increase in REVPAR was mainly due to higher average room rates, partially offset by decreased occupancy, at all of the Company’s hospitality operating regions.

Real Estate revenue was \$4 million higher year over year. The growth in Real Estate revenue was attributable to enhanced performance throughout all of the real estate operating regions, as well as the contribution from the real estate operations of the Delta Regina since August 2007. The occupancy rate of the Real Estate Division was 96.8 per cent as at December 31, 2008, consistent with the rate as at December 31, 2007.

Management Discussion and Analysis

Earnings: Earnings were \$1 million lower than the previous year. Excluding a \$2 million favourable corporate tax adjustment in 2007 associated with opening future income tax liability balances as a result of lower enacted corporate income tax rates, earnings were \$1 million higher year over year. The increase was mainly due to a full year of earnings from the Delta Regina, which was acquired in August 2007.

Outlook: The Hospitality Division currently operates in eight Canadian provinces. Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall impact on leisure and business travel and hotel stays.

The Real Estate Division operates primarily in Atlantic Canada, with the majority of its properties located in large regional markets that contain a broad economic base. The buildings are occupied by a diversified tenant base characterized by long-term leases with staggered maturity dates to reduce the risk of vacancy exposure.

Corporate and Other⁽¹⁾

Financial Highlights

Years Ended December 31

(\$ millions)

	2008	2007 ⁽¹⁾	Variance
Revenue	26	22	4
Operating Expenses	16	13	3
Amortization	8	6	2
Finance Charges ⁽²⁾	80	70	10
Corporate Tax Recovery	(23)	(12)	(11)
Preference Share Dividends	14	6	8
Net Corporate and Other Expenses	(69)	(61)	(8)

⁽¹⁾ Includes Fortis net corporate expenses and, from May 17, 2007, the net expenses of non-regulated Terasen corporate-related activities and the financial results of Terasen's 30 per cent ownership interest in CWLP and Terasen's non-regulated wholly owned subsidiary TES

⁽²⁾ Includes dividends on preference shares classified as long-term liabilities

Revenue: Revenue was \$4 million higher than the previous year. Higher interest revenue from increased inter-company lending was combined with increased revenue contributions from CWLP. CWLP contributed revenue for a full year in 2008 compared to a partial year in 2007; however, this increase was partially offset by the impact of a decrease in the number of customer contracts at CWLP.

Net Corporate and Other Expenses: Net corporate and other expenses were \$8 million higher than the previous year, primarily due to Terasen acquisition-related finance charges and other Terasen corporate-related expenses for a full year in 2008 compared to a partial year in 2007. The increase also reflected higher preference share dividends associated with the 9.2 million First Preference Shares, Series G issued in the second quarter of 2008 for gross proceeds of \$230 million and higher business development costs. The increase in net corporate and other expenses was partially offset by a higher corporate tax recovery and higher interest revenue from increased inter-company lending. The corporate tax recovery in 2008 was favourably impacted by a \$2 million tax reduction associated with the settlement of historical corporate tax matters at Terasen. The corporate tax recovery in 2007 was reduced as a result of purchase price allocation tax adjustments and by the impact of lower enacted future corporate income tax rates.

In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately \$300 million. The net proceeds were used to repay short-term debt that was primarily incurred to retire \$200 million of debt at Terasen that matured on December 1, 2008 and for general corporate purposes.

Outlook: While currently not significant, financial results of TES are also reported in the Corporate and Other segment. TES expects to increase its activities in the development, building, owning and operating of geothermal energy systems, community piping and energy transfer systems to harness renewable energy sources. TES is entering into agreements with developers to provide alternative thermal energy systems for both residential and commercial development projects in British Columbia. In October 2008, TES signed an agreement to build a centralized heating and cooling system for a new Okanagan lakefront community project. TES will own and operate this alternative energy system. In December 2008, TES signed an agreement to build and manage an alternative district energy system in Coquitlam, British Columbia. The project is expected to commence in the fall of 2009 and be operational as early as 2011.

Management Discussion and Analysis

Regulatory Highlights

The nature of regulation and summary of material regulatory decisions and applications associated with each of the Corporation's regulated gas and electric utilities are summarized as follows:

Nature of Regulation

Regulated Utility	Regulatory Authority	Allowed Common Equity (%)	Allowed Returns (%)			Supportive Features
			2007	2008	2009	
			ROE			Cost of Service ("COS")/ROE
TGI	BCUC	35	8.37	8.62	8.47	PBR mechanism through 2009: TGI: 50/50 sharing of earnings above or below the allowed ROE
TGVI	BCUC	40	9.07	9.32	9.17	TGVI: 100 per cent retention of earnings from lower-than-forecasted operating and maintenance costs but no relief from increased operating and maintenance costs ROE automatic adjustment formula tied to long-term Canada bond yields
FortisBC	BCUC	40	8.77	9.02	8.87	Future Test Year COS/ROE PBR mechanism for 2009 through 2011: 50/50 sharing of earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE – excess to deferral account ROE automatic adjustment formula tied to long-term Canada bond yields
FortisAlberta	AUC	37	8.51	8.75	8.51 ⁽¹⁾	Future Test Year COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields
Newfoundland Power	Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB")	45	8.60 +/- 50 bps	8.95 +/- 50 bps	8.95 +/- 50 bps	Future Test Year COS/ROE ROE automatic adjustment formula tied to long-term Canada bond yields
Maritime Electric	Island Regulatory and Appeals Commission ("IRAC")	40	10.25	10.00	9.75	Future Test Year COS/ROE
FortisOntario	OEB (Canadian Niagara Power) Franchise Agreement (Cornwall Electric)	43.3 ⁽²⁾	9.00	9.00	8.39	Canadian Niagara Power – COS/ROE Cornwall Electric – Price cap with commodity cost flow through Future Test Year – beginning in 2009
Belize Electricity	Public Utilities Commission ("PUC")	N/A	10.00 – 15.00	10.00	10.00 ⁽³⁾	Four-year COS/ROA agreements Additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Future Test Year
Caribbean Utilities	Electricity Regulatory Authority ("ERA")	N/A	15.00	9.00 – 11.00	9.00 – 11.00	COS/ROA Rate-cap adjustment mechanism based on published consumer price indices Under the new licences, the Company may apply for a special additional rate to customers in the event of a disaster, including a hurricane. Historical Test Year
Fortis Turks and Caicos	Utilities make annual filings with the Energy Commission	N/A	17.50 ⁽⁴⁾	17.50 ⁽⁴⁾	17.50 ⁽⁴⁾	COS/ROA If the actual ROA is lower than the allowed ROA, due to additional costs resulting from a hurricane or other event, the Company may apply for an increase in customer rates in the following year. Future Test Year

⁽¹⁾ Interim ROE pending the outcome of the AUC's 2009 Generic Cost of Capital Proceeding

⁽²⁾ Allowed deemed equity component of the capital structure for 2009. For 2008, the allowed deemed equity component of the capital structure was 46.7 per cent.

⁽³⁾ Based on the June 2008 Final Decision on Belize Electricity's 2008/2009 rate application

⁽⁴⁾ Amount provided under licence. Actual ROAs achieved in 2007 and 2008 were lower than the ROA allowed under the licence due to significant investment occurring at the utility.

Management Discussion and Analysis

Material Regulatory Decisions and Applications

Regulated Utility	Summary Description
TGI/TGVI	- In December 2007, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2008. Increased mid-stream costs are flowed through to customers without markup. The approved rates also reflected the impact of an increase in the allowed ROE for 2008 to 8.62 per cent and 9.32 per cent for TGI and TGVI, respectively. - On April 1, 2008, final regulatory approval for the construction of the 1.5 billion-cubic foot liquefied natural gas storage facility on Vancouver Island was received for a total estimated cost of approximately \$200 million. - Every three months, TGI and TGVI review natural gas and propane commodity prices with the BCUC in order to ensure the flow-through rates charged to customers are sufficient to cover the cost of purchasing natural gas and propane. Effective April 1, 2008 and July 1, 2008, the BCUC approved increases in the commodity rates charged to TGI customers for natural gas and propane. Effective October 1, 2008, the BCUC approved decreases in the commodity rates charged to TGI customers for natural gas. The commodity cost of natural gas and propane are flowed through to customers without markup. During 2008, no commodity rate changes were made at TGVI. - In December 2008, the BCUC approved various rates at TGI and TGVI, including those for mid-stream and delivery for residential customers in several service areas, effective January 1, 2009. The approved rates also reflected the impact of a decrease in the allowed ROE for 2009 to 8.47 per cent and 9.17 per cent for TGI and TGVI, respectively, resulting from the application of automatic ROE adjustment mechanisms. The commodity rate for natural gas will remain unchanged and the commodity rate for propane will decrease effective January 1, 2009. - TGI filed an application with the BCUC in the fourth quarter of 2008 requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive regulatory approval for this \$27 million project in early 2009 with completion of the project anticipated in 2010. - TGI and TGVI are currently preparing rate applications related to 2010 which are anticipated to be filed with the BCUC in the second quarter of 2009. The BCUC approval of rates for 2010 and future years will be required as the current PBR agreements expire at the end of 2009. As part of the rate filings, TGI and TGVI plan to seek a review of the current generic ROE adjustment mechanisms and the deemed equity component of the utilities' capital structures.
FortisBC	- In December 2007, regulatory approval was received for the NSA associated with 2008 revenue requirements resulting in a customer rate increase of 2.9 per cent, effective January 1, 2008. The rate increase was primarily the result of the Company's capital expenditure program. Rates for 2008 reflected an allowed ROE of 9.02 per cent. - In April 2008, the BCUC approved an interim increase of 0.8 per cent to FortisBC's customer rates, effective May 1, 2008, as a result of BC Hydro's interim rate increase, which increased FortisBC's cost to purchase power from BC Hydro by 5.06 per cent. - In June 2008, FortisBC filed its 2009 and 2010 Capital Expenditure Plan for gross capital expenditures of approximately \$193 million for 2009 and \$196 million for 2010. In November 2008, the BCUC denied the costs relating to the Copper Conductor Replacement Project and Advanced Metering Infrastructure Project included in the 2009 and 2010 Capital Expenditure Plan. These projects would have totalled approximately \$21 million in 2009 and \$27 million in 2010. In February 2009, the BCUC issued its decision on the Company's 2009 and 2010 Capital Expenditure Plan. Total gross capital expenditures of \$165 million were approved for 2009 and \$156 million were approved for 2010. An additional \$16 million of capital expenditures is subject to further regulatory processes. - In December 2008, the BCUC approved the Company's 2009 Revenue Requirements Application resulting in a general rate increase of 4.6 per cent, effective January 1, 2009. The rate increase is primarily the result of the Company's capital expenditure program and higher power purchases driven by customer growth and increased electricity demand. Rates for 2009 reflect an allowed ROE of 8.87 per cent as a result of the application of the automatic ROE adjustment mechanism. The approval of the 2009 Revenue Requirements Application also included an extension of the PBR mechanism for the years 2009 through 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a formula incorporating customer growth and inflation, i.e., the consumer price index ("CPI") for British Columbia minus a productivity improvement factor ("PIF") of 3 per cent in 2009, 1.5 per cent in 2010 and 1.5 per cent in 2011. Should inflation be in excess of 3 per cent, the excess is to be added to the PIF, which effectively caps the CPI at 3 per cent.
FortisAlberta	- Effective January 1, 2008, FortisAlberta became regulated by the AUC due to the separation of the Alberta Energy and Utilities Board into two separate regulatory bodies. - In February 2008, regulatory approval was received of the NSA associated with 2008/2009 revenue requirements, resulting in distribution rate increases of 6.8 per cent, effective January 1, 2008, and 7.3 per cent, effective January 1, 2009. The approved NSA includes forecast gross capital expenditures of approximately \$264 million for 2008 and \$296 million for 2009, primarily to meet customer growth and improve system reliability. The 2008 revenue requirements included in the 2008/2009 NSA were determined using the 2007 allowed ROE of 8.51 per cent. The impact of the increase in the allowed ROE to 8.75 per cent for 2008 was subject to deferral-account treatment and, as such, was recognized as earned in 2008 and will be collected in customer rates in 2009.

Management Discussion and Analysis

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisAlberta (cont'd)	- In June 2008, the AUC ruled that a review of ROE levels, adjustment mechanisms and utility capital structures in a generic proceeding would be appropriate. In July 2008, the AUC issued its notice of application, preliminary scoping document and minimum filing requirements for the 2009 Generic Cost of Capital Proceeding. The proceeding applies to all gas, electric and pipeline utilities in Alberta that are regulated by the AUC. - In November 2008, FortisAlberta submitted its evidence with respect to the 2009 Generic Cost of Capital Proceeding as requested by the AUC. A hearing is scheduled for the second quarter of 2009. - In December 2008, FortisAlberta received regulatory approval for its 2009 distribution rates to recover approved distribution costs. The result is a distribution rate increase of 8.6 per cent, effective January 1, 2009. The rate increase is slightly higher than the rate increase of 7.3 per cent contemplated in the 2008/2009 NSA due to the deferred recovery in customer rates in 2009 of the increase in the allowed ROE to 8.75 per cent in 2008. The approved rates for 2009 also reflect the impact of the Company's union agreement, which was settled after the 2008/2009 NSA was approved. As directed by the AUC, the Company is to continue using the 2007 allowed ROE of 8.51 per cent for 2009, pending the outcome of the 2009 Generic Cost of Capital Proceeding. - FortisAlberta expects to file a 2010 and 2011 revenue requirements application during the second quarter of 2009.
Newfoundland Power	- In December 2007, the PUB approved the Company's NSA associated with the 2008 general rate application, resulting in an average 2.8 per cent increase in customer rates, effective January 1, 2008. The rate increase was largely driven by higher amortization costs. The rate increase also reflected the impact of an increase in the allowed ROE to 8.95 per cent for 2008. - The PUB-approved NSA also results in, among other things: (i) the amortization of \$7.2 million in 2008 and \$4.6 million in each of 2009 and 2010 of the remaining \$16.4 million balance of the original December 2005 unbilled revenue liability; (ii) amortization of approximately \$3.9 million in each of 2008, 2009 and 2010 of previously deferred amortization expense; (iii) amortization over a period of three years to five years of certain deferred regulatory balances; and (iv) for 2008 through 2010, the deferral of variations in purchase power expense caused by differences in the actual unit cost of energy and the unit cost reflected in customer rates to be recovered from, or refunded to, customers through operation of the Company's rate stabilization account. - Effective July 1, 2008, the PUB approved an average 5.9 per cent increase in customer electricity rates, reflecting the flow through to customers, by operation of the rate stabilization account, of variances in the cost of fuel used to generate electricity that Newfoundland Hydro sells to Newfoundland Power. The increase in customer rates had no impact on Newfoundland Power's earnings in 2008. - In November 2008, the PUB approved, as filed, the Company's 2009 Capital Budget Application for approximately \$62 million, with approximately half of the proposed capital expenditures relating to replacing aged and deteriorated components of the electricity system. - The Company's allowed ROE of 8.95 per cent remains unchanged for 2009 and, consequently, there has been no change in basic customer rates for 2009.
Maritime Electric	- In January 2008, IRAC approved, as filed, an increase in basic electricity rates of 1.8 per cent, effective April 1, 2008, and approved a maximum allowed ROE of 10.0 per cent for 2008. - In April 2008, IRAC ordered the energy cost adjustment mechanism ("ECAM") amortization period of 12 months to be set at 8 months, effective May 1, 2008. The result is an increase in the flow through in customer rates of the recovery of ECAM over the shorter amortization period. - In September 2008, IRAC approved, as filed, the Company's amendment of approximately \$14 million to its 2008 Capital Budget to reflect the construction of a new transmission line to facilitate the expansion of merchant wind development. The project is being financed entirely by customer contributions. - In November 2008, IRAC approved, as filed, the Company's 2009 Capital Budget Application for approximately \$20 million, before customer contributions. - In March 2009, IRAC approved Maritane Electric's 2009 Rate Application, which will result in an increase in the amount of energy-related costs to be collected from customers through the basic rate component of customer billings, effective April 1, 2009. The increase in the reference cost of energy in basic rates from 6.73 cents per kWh to 7.7 cents per kWh will result in a decrease in the amount of energy costs to be collected from customers through the operation of the ECAM. Additionally, IRAC approved the deferral of Point Lepreau Nuclear Generating Station replacement energy costs for 2009 and an increase in the amortization period of the ECAM to 12 months, effective April 1, 2009. IRAC also approved, as filed, a maximum allowed ROE of 9.75 per cent for 2009, down from an allowed ROE of 10.00 per cent for 2008. The overall impact on residential customer rates for 2009 will be an increase of 5.3 per cent based on average consumption of 650 kWh per month.
FortisOntario	In March 2008, the OEB issued its decision relating to the 2008 Incentive Regulation Mechanism ("IRM") application filed by Canadian Niagara Power. The result was an average 1.1 per cent increase in electricity distribution rates for operations in Fort Erie, Port Colborne and Gananoque, effective May 1, 2008. The increase was comprised of a 2.1 per cent increase for inflation, partially offset by a 1.0 per cent decrease for a productivity adjustment. Under the 2008 IRM, Canadian Niagara Power's capital structure for 2008 was deemed at 53.3 per cent debt and 46.7 per cent equity, as part of the OEB's plan to move to a 60 per cent debt and 40 per cent equity capital structure over a three-year period.

Management Discussion and Analysis

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
FortisOntario (cont'd)	- Effective July 1, 2008, retail rates at Cornwall Electric decreased by approximately 6.2 per cent, attributable to a new 11.5-year wholesale electricity supply contract negotiated with Hydro-Québec Energy Marketing by Cornwall Electric on behalf of its customers. The new long-term agreement replaces an existing short-term contract and ensures reliability of supply and rate stability. - In August 2008, Canadian Niagara Power filed a 2009 Cost of Service Application requesting the rebasing of distribution rates using 2009 as a forward test year. The application assumes a deemed capital structure of 56.7 per cent debt and 43.3 per cent equity and, as required by the OEB, reflects a preliminary ROE of 8.39 per cent. The application proposes distribution rate increases of 4.9 per cent, 9.4 per cent and 7.1 per cent for Fort Erie, Gananoque and Port Colborne, respectively, effective May 1, 2009. The proposed increases are primarily driven by the impact of distribution system upgrades. The hearing process associated with the application commenced during the fourth quarter of 2008 and the Company expects a decision on the application to be received in April 2009.
Belize Electricity	- In March 2008, the newly elected Government of Belize repealed December 2007 amendments to the <i>Electricity (Tariffs, Charges and Quality of Services Standards) Bylaws</i>. The amendments had simplified Belize Electricity's rate-setting methodology, allowed for improved rate stabilization and settled outstanding matters related to the PUC's Final Decision on electricity rates for the period July 1, 2007 through June 30, 2008. - In March 2008, Belize Electricity filed an application requesting an increase in the cost of power component of the average electricity rate by 15 per cent, or BZ6.5 cents per kilowatt hour ("kWh"), as a result of the rapid increase in the cost of power due to increasing world oil prices. The application was disallowed by the PUC which cited that, in the interim, a decrease in the Company's operating expenses and capital expenditure levels would help offset the impact on cash flow of the increasing cost of power. Additionally, the PUC indicated it would defer its detailed analysis of the high deferrals of cost of power into Belize Electricity's cost of power rate stabilization account ("CPRSA") until the Annual Tariff Review Proceeding for the annual tariff period for July 1, 2008 to June 30, 2009. - In April 2008, Belize Electricity filed its Annual Tariff Review Application for the annual tariff period from July 1, 2008 to June 30, 2009 ("2008/2009 Rate Application") requesting a 13.4 per cent increase in the average electricity rate, as a result of an increase in the cost of power component of the rate and an increase in the recovery of the CPRSA. - In May 2008, the PUC issued its Initial Decision on Belize Electricity's 2008/2009 Rate Application. The Initial Decision denied any average rate increase and approved, among other things, a retroactive adjustment to Belize Electricity's CPRSA. Belize Electricity objected to the Initial Decision, which resulted in a review of the Initial Decision by a PUC-appointed Independent Expert. The report of the Independent Expert reiterated many of Belize Electricity's concerns pertaining to the Initial Decision. - In June 2008, the PUC issued its Final Decision on Belize Electricity's 2008/2009 Rate Application which rejected most of the recommendations of the Independent Expert and failed to increase the overall average electricity rate. The PUC also ordered a BZ\$36 million retroactive adjustment associated with Belize Electricity's prior years' financial results. The adjustment, in substance, represented the disallowance of previously incurred fuel and purchased power costs. The PUC also reduced Belize Electricity's targeted allowed ROA to 10 per cent from 12 per cent through a reduction in the VAD component of the average electricity rate. The Final Decision would have the impact of reducing the Corporation's share of Belize Electricity's earnings by approximately \$5 million over a 12-month period. The Final Decision does not impact the Corporation's non-regulated generation operations in Belize. - As a direct result of the Final Decision, Belize Electricity recorded an \$18 million (BZ\$36 million) charge (\$13 million of which was the Corporation's share) to energy supply costs during the second quarter of 2008. - The Final Decision also proposed the use of an automatic mechanism, to be finalized by the PUC, to adjust monthly, on a two-month lag basis, the cost of power component of the rate to reflect actual costs of power. The automatic adjustment mechanism, which was retroactive effective September 1, 2008, allows for the collection from, or rebate to, customers of actual costs of power which vary from a reference cost of power by more than a threshold of 10 per cent. - In February 2009, the PUC amended the Final Decision on Belize Electricity's 2008/2009 Rate Application (the "Amendment"), effective for the period from January 1, 2009 through June 30, 2009. The Amendment provides for an increase in the VAD component of the average electricity rate to allow Belize Electricity to earn a targeted allowed ROA of 12 per cent but reduces the reference cost of power component of the average electricity rate, due to an overall decline in the cost of power. The Amendment, therefore, allows for an overall decrease in the average electricity rate from BZ44.1 cents per kWh to BZ37.5 cents per kWh. The Amendment also provides for a lower regulated asset value upon which the allowed ROA is calculated, while increasing operating expenses by the same amount, and reduces depreciation, taxes and fees and the related revenue requirement. - Changes made in electricity legislation by the Government of Belize and the PUC and the June 2008 Final Decision and Amendment, which were based on the changed legislation, have been judicially challenged by Belize Electricity in several proceedings. The judicial process is ongoing with interim rulings, judgments and appeals. The timing or likely outcome of the proceedings is indeterminable at this time.

Management Discussion and Analysis

Material Regulatory Decisions and Applications (cont'd)

Regulated Utility	Summary Description
Caribbean Utilities	- In December 2007, an Agreement in Principle ("AIP") was reached with the Government of the Cayman Islands on the terms of a new exclusive T&D licence and a new non-exclusive generation licence. - In April 2008, the new licences were granted. The terms of the new licences included competition for future generation capacity and general promotion of renewable sources of energy. The T&D licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The generation licence is for a period of 21.5 years, expiring September 2029. The terms of the new licences remained substantially the same as the terms outlined in the AIP. - Effective January 1, 2008, as a result of the AIP and subsequent granting of the new licences, basic customer rates were reduced by 3.25 per cent, the hurricane CRS was removed, a fuel-duty rebate funded by the Government of the Cayman Islands was implemented for residential customers consuming less than 1,500 kWh monthly, and basic rates were restructured to extract all fuel costs and licence fee amounts which are now being flowed through to customers. The 3.25 per cent reduction in basic rates reduced annual revenue by approximately US\$2.1 million. Additionally, Caribbean Utilities has forgone US\$2.6 million of revenue in 2008 as a result of the early elimination of the hurricane CRS. A new fuel and oil rate factor was also established to provide for the full flow through of fuel and oil costs to customers. - Following the initial basic rate reduction, customer rates will be frozen until May 31, 2009 and will be subject to annual review and adjustment each June thereafter. Under the new T&D licence, a mechanism will be used to adjust basic rates in accordance with a formula that is based on published CPIs, thereby taking inflation into account. The rate-adjustment mechanism is designed to maintain Caribbean Utilities' allowed ROA in a targeted range of 9 per cent to 11 per cent, down from an allowed ROA of 15 per cent permitted under the previous licence. The recently amended <i>Electricity Regulatory Authority Law</i> (2005 Revision) provides for the conduct of a competitive bid process to be managed by the ERA for new generating capacity and the replacement of retired generating capacity. The first competitive process under the new generation licence began in May 2008 with a filing of a Certificate of Need by Caribbean Utilities for the installation of 16 MW of additional generating capacity in each of 2011 and 2012. Based on slowing economic growth, the Company has advised the ERA that the capacity is not required until a year later. In March 2009, the ERA approved the Certificate of Need for 16 MW of generating capacity in each of 2012 and 2013. - In July 2008, Caribbean Utilities began a formal request for expressions of interest from qualified wind-generation developers for a wind-generation project for up to 10 MW. The ERA has endorsed this initiative and any power purchase agreements or generating licence arising from this initiative will be subject to ERA approval. - In July 2008, Caribbean Utilities filed with the regulator a Five-Year Capital Investment Plan ("CIP") totalling US\$255 million. - In December 2008, Caribbean Utilities filed with the regulator a revised Five-Year CIP as a result of the change in the Company's fiscal year end. The revised CIP still totalled US\$255 million, including approximately US\$72 million related to new generation that is expected to be solicited. In January 2009, the regulator requested that the Company further review its non-generation capital expenditures to reflect the current economic environment and lower growth projections. A revised CIP totalling US\$246 million was subsequently submitted to the ERA. A decision on the revised CIP is expected during the first quarter of 2009. - In January 2009, the ERA approved a new customer-owned renewable energy tariff that will allow customers on Grand Cayman to connect renewable energy systems to the Company's distribution system and generate their own power from renewable energy while remaining connected to Caribbean Utilities' grid. The Company expects to be able to connect customers to the grid by the end of the first quarter of 2009.
Fortis Turks and Caicos	- In May 2008, Fortis Turks and Caicos received approval from the Government of the Turks and Caicos Islands to supply wholesale electricity under an exclusive licence to Dellis Cay on the Turks and Caicos Islands. - In March 2009, Fortis Turks and Caicos submitted its 2008 annual regulatory filing outlining the Company's performance in 2008 and its capital expansion plans for 2009.

Management Discussion and Analysis

Consolidated Financial Position

The following table outlines the significant changes in the consolidated balance sheets of Fortis between December 31, 2008 and December 31, 2007.

Significant Changes in the Consolidated Balance Sheets between December 31, 2008 and December 31, 2007

Balance Sheet Account	Increase/ (Decrease) (\$ millions)	Explanation
Accounts receivable	46	The increase was primarily due to the impacts of cooler weather and an increase in the commodity cost of natural gas charged to customers at the Terasen Gas companies in December 2008 compared to December 2007.
Regulatory assets – current and long-term	48	The increase was driven by the deferral of 2008 AESO charges at FortisAlberta, an increase in the deferral of other post-employment benefit costs and the deferral of an increase in the cost of fuel and power at Maritime Electric and Caribbean Utilities. The increase was partially offset by a decrease in the deferral of the commodity cost of natural gas at the Terasen Gas companies and the cost of fuel and purchased power at Belize Electricity. The decrease at Belize Electricity was driven by an \$18 million (BZ\$36 million) adjustment as a result of a regulatory rate decision in 2008.
Inventories	22	The increase was primarily associated with inventories of natural gas at the Terasen Gas companies due to an increase in the average price of natural gas in December 2008 compared to December 2007.
Deferred charges and other assets	100	The increase was mainly due to the reclassification of hydroelectric generating facility assets of the Exploits Partnership from utility capital assets as at December 31, 2008. The increase was also due to \$31 million in contributions made by FortisAlberta to the AESO for transmission capital projects during 2008 and an increase in deferred defined benefit pension costs. Refer to the “Contingencies” section of this MD&A for a further discussion of the Exploits Partnership.
Future income tax assets – long-term	17	The increase primarily related to future income tax recoveries associated with unrealized foreign exchange losses incurred upon the translation of the Corporation’s US dollar-denominated long-term debt due to the weakening of the Canadian dollar against the US dollar.
Utility capital assets	619	The increase primarily related to \$890 million invested in electricity and gas systems combined with the impact of foreign exchange on the translation of foreign currency-denominated utility capital assets. The increase was partially offset by customer contributions and amortization for 2008 and the reclassification of hydroelectric generating facility assets of the Exploits Partnership to deferred charges and other assets as at December 31, 2008.
Income producing properties	22	The increase primarily related to the acquisition of the Fairmont Newfoundland hotel in November 2008.
Goodwill	31	The increase primarily related to the impact of foreign exchange on the translation of US dollar-denominated goodwill and goodwill associated with the Corporation’s additional investment in Caribbean Utilities as a result of the Corporation’s participation in Caribbean Utilities’ Rights Offering in August 2008. The increase was partially offset by a \$6 million reduction associated with the recognition in 2008 of the benefit of tax losses at Terasen which related to periods prior to the Corporation’s ownership of Terasen.
Short-term borrowings	(65)	The decrease was primarily due to the repayment of short-term borrowings by Maritime Electric and TGI with proceeds from the issuance of long-term debt.
Accounts payable and accrued charges	81	The increase was primarily due to higher natural gas costs payable at the Terasen Gas companies due to increased consumption as a result of cooler weather in December 2008 compared to December 2007, combined with higher accounts payable at Maritime Electric due to the timing of payments of energy supply costs. The increase was partially offset by a decrease in amounts owing at FortisAlberta due to the timing of payments to the AESO for transmission costs.
Income taxes payable	36	The increase was mainly due to taxes associated with regulatory-deferral accounts at the Terasen Gas companies combined with the timing of income tax payments and the accrual of current income taxes at the Terasen Gas companies and Newfoundland Power. The increase was partially offset by an approximate \$17 million payment associated with the Québec Trust tax settlement at Terasen.
Regulatory liabilities – current and long-term	54	The increase was driven by the deferral, during the latter part of 2008, of amounts owing to customers due to lower actual commodity cost of natural gas at the Terasen Gas companies and lower cost of fuel and purchased power at Belize Electricity compared to amounts collected in customer rates and an increase in the regulatory provision for future asset removal and site restoration costs. The increase was partially offset by a decrease in the unbilled revenue liability at Newfoundland Power in accordance with PUB-approved amortization.
Deferred credits	16	The increase was primarily due to an increase in supplementary defined benefit pension and other post-employment benefit liabilities.

Management Discussion and Analysis

Significant Changes in the Consolidated Balance Sheets between December 31, 2008 and December 31, 2007 (cont'd)

Balance Sheet Account	Increase/ (Decrease) (\$ millions)	Explanation
Long-term debt and capital lease obligations (including current portion)	65	The increase was primarily due to the issuance of long-term debt and the impact of foreign exchange on the translation of foreign currency-denominated debt, partially offset by a net decrease in committed credit-facility borrowings, as well as by regularly scheduled debt maturities and repayments. The issuance of long-term debt, primarily to repay committed credit-facility borrowings, short-term borrowings and maturing long-term debt, was comprised of a \$250 million unsecured debenture offering by TGI, a \$250 million unsecured debenture offering by TGVI, a \$100 million senior unsecured debenture offering by FortisAlberta and a \$60 million secured first mortgage bond issue by Maritime Electric. The net \$309 million decrease in committed credit-facility borrowings was driven by net repayments at the Terasen Gas companies and the Corporation, partially offset by net borrowings at FortisAlberta and FortisBC. The regularly scheduled debt repayments included the repayment of \$188 million of maturing debt at TGI and \$200 million of maturing debt at Terasen Inc.
Non-controlling interest	30	The increase primarily related to the impact of foreign exchange on the translation of foreign currency-denominated non-controlling interest amounts, combined with the Corporation's non-controlling interest in Caribbean Utilities' US\$28 million Rights Offering in August 2008. The increase was partially offset by the Corporation's non-controlling interest in the net loss incurred at Belize Electricity in 2008, which was mainly the result of the PUC's decision on the Company's 2008/2009 Rate Application.
Shareholders' equity	670	The increase was driven by a \$300 million common share issue (\$291 million net of after-tax expenses) and a \$230 million preference share issue (\$225 million net of after-tax expenses), combined with net earnings reported for 2008, less common share dividends. The remainder of the increase related to the issuance of common shares under the Corporation's share purchase, dividend reinvestment and stock option plans and a decrease in accumulated other comprehensive loss.

Liquidity and Capital Resources

The table below outlines the Corporation's sources and uses of cash in 2008, as compared to 2007, followed by a discussion of the nature of the variances in cash flows year over year.

Summary of Cash Flows

Years Ended December 31

(\$ millions)

	2008	2007	Variance
Cash, Beginning of Year	58	41	17
Cash Provided By (Used In)			
Operating Activities	663	373	290
Investing Activities	(854)	(2,033)	1,179
Financing Activities	196	1,680	(1,484)
Foreign Currency Impact on Cash Balances	3	(3)	6
Cash, End of Year	66	58	8

Management Discussion and Analysis

Operating Activities: Cash flow from operating activities, after working capital adjustments, in 2008 was \$290 million higher than the previous year. An increase in cash flow from operating activities, after working capital adjustments, of \$380 million at the Terasen Gas companies was combined with the impact of favourable working capital changes at Newfoundland Power. The Terasen Gas companies contributed to the financial results of the Corporation for a full year in 2008 compared to a partial year in 2007. The increase was partially offset by lower cash flow from operating activities, after working capital adjustments, at FortisAlberta. However, cash from operating activities in 2007 at FortisAlberta reflected the favourable impact of the sale of amounts in the Company's AESO charges deferral account, corporate tax refunds received and the timing of the payment of AESO transmission costs.

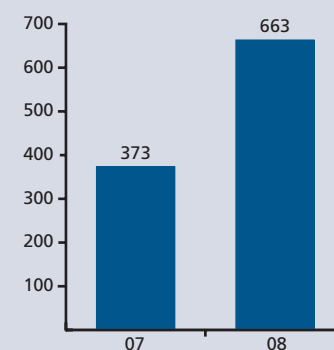
Investing Activities: Cash used in investing activities in 2008 was approximately \$1.2 billion lower than the previous year. Investing activities in 2007, however, included the impact of the approximate \$1.3 billion cash payment for the acquisition of Terasen in May 2007 and the approximate \$50 million acquisition of the Delta Regina in August 2007. Excluding the impact of the acquisitions of Terasen and the Delta Regina in 2007, cash used in investing activities was \$124 million higher year over year. The increase was driven by higher utility capital expenditures and changes in deferred charges, other assets and deferred credits, partially offset by an increase in contributions received in aid of construction and an increase in proceeds from the sale of capital assets. In January 2008, TGI received \$14 million of proceeds associated with the sale of surplus land in December 2007. Investing activities for 2008 also included the approximate \$22 million acquisition of the Fairmont Newfoundland hotel in November 2008.

Gross utility capital expenditures in 2008 were \$890 million, \$100 million higher than last year. The increase was driven by the Terasen Gas companies and FortisAlberta, partially offset by lower capital spending at FortisBC. The net increase in the use of cash associated with changes in deferred charges, other assets and deferred credits of \$27 million was driven by higher contributions by FortisAlberta to AESO transmission capital projects. Contributions received in aid of construction in 2008 were \$12 million higher than last year, primarily related to the Terasen Gas companies and Maritime Electric, partially offset by lower contributions received at FortisAlberta.

Financing Activities: Cash provided by financing activities in 2008 was approximately \$1.5 billion lower than the previous year. Financing activities in 2007 included the issuance of common shares, for gross proceeds of \$1.15 billion, to finance a significant portion of the cash purchase price of Terasen. Excluding the impact of financing the acquisition of Terasen in 2007, cash provided by financing activities was \$382 million lower in 2008 compared to 2007. The decrease was mainly due to higher net repayments of short-term and committed credit-facility borrowings, lower proceeds from long-term debt and higher repayments of long-term debt. The decrease was partially offset by net proceeds from the \$300 million common share issue during the fourth quarter of 2008 and the \$230 million preference share issue during the second quarter of 2008 compared to net proceeds from a \$150 million common share issue during the first quarter of 2007.

Net repayments of short-term borrowings were \$69 million for 2008 compared to proceeds from net short-term borrowings of \$103 million in 2007. The net repayments in 2008 were driven by Maritime Electric and the Terasen Gas companies, with partial proceeds from the issuance of long-term debt in 2008.

Cash Flow from Operating Activities
(\$ millions)



Management Discussion and Analysis

Proceeds from long-term debt, net of issue costs, repayments of long-term debt and capital lease obligations, and net borrowings (repayments) under committed credit facilities for 2008 compared to 2007 are summarized in the following tables.

Proceeds from Long-Term Debt, Net of Issue Costs

Years Ended December 31

(\$ millions)	2008	2007	Variance
Terasen Gas Companies	496 ⁽¹⁾⁽²⁾	250 ⁽³⁾	246
FortisAlberta	99 ⁽⁴⁾	110 ⁽⁵⁾	(11)
FortisBC	–	104 ⁽⁶⁾	(104)
Newfoundland Power	–	70 ⁽⁷⁾	(70)
Maritime Electric	60 ⁽⁸⁾	–	60
Caribbean Utilities	–	48 ⁽⁹⁾	(48)
Corporate – Fortis Inc.	–	209 ⁽¹⁰⁾	(209)
Other	7	6	1
Total	662	797	(135)

⁽¹⁾ Issued February 2008, \$250 million 6.05% Senior Unsecured Debentures by TGV, due February 2038. The net proceeds were used to repay committed credit-facility borrowings.

⁽²⁾ Issued May 2008, \$250 million 5.80% Medium-Term Unsecured Note Debentures by TGI, due May 2038. The net proceeds were primarily used to repay maturing \$188 million 6.20% debentures and short-term borrowings.

⁽³⁾ Issued October 2007, \$250 million 6.00% Medium-Term Unsecured Note Debentures by TGI, due October 2037. The net proceeds were used to repay maturing \$250 million 6.50% long-term debt.

⁽⁴⁾ Issued April 2008, \$100 million 5.85% Senior Unsecured Debentures, due April 2038. The net proceeds were used to repay committed credit-facility borrowings.

⁽⁵⁾ Issued January 2007, \$110 million 4.99% Senior Unsecured Debentures, due January 2047. The net proceeds were used to repay committed credit-facility borrowings.

⁽⁶⁾ Issued July 2007, \$105 million 5.90% Senior Unsecured Debentures, due July 2047. The net proceeds were used to repay committed credit-facility borrowings and for general corporate purposes, including capital expenditures.

⁽⁷⁾ Issued August 2007, \$70 million 5.90% Secured First Mortgage Sinking Fund Bonds, due August 2037. The net proceeds were used to repay committed credit-facility borrowings and maturing \$31.5 million 11.875% Secured First Mortgage Sinking Fund Bonds.

⁽⁸⁾ Issued April 2008, \$60 million 6.05% Secured First Mortgage Bonds, due April 2038. The proceeds were used to repay short-term borrowings.

⁽⁹⁾ Issued June 2007, US\$30 million 5.65% Senior Unsecured Notes, due June 2022. Issued November 2007, US\$10 million 5.65% Senior Unsecured Notes, due June 2022. The net proceeds were used to repay debt and finance capital expenditures.

⁽¹⁰⁾ Issued September 2007, US\$200 million 6.60% Senior Unsecured Notes, due September 2037. The net proceeds were primarily used to repay committed credit-facility borrowings associated with the Terasen acquisition and for general corporate purposes.

Repayment of Long-Term Debt and Capital Lease Obligations

Years Ended December 31

(\$ millions)	2008	2007	Variance
Terasen Gas Companies	(193)	(250)	57
Newfoundland Power	(5)	(36)	31
Caribbean Utilities	(11)	(18)	7
Fortis Generation – BECOL	–	(28)	28
Fortis Properties	(13)	(20)	7
Corporate – Terasen Inc.	(200)	–	(200)
Other	(9)	(11)	2
Total	(431)	(363)	(68)

Net (Repayments) Borrowings Under Committed Credit Facilities

Years Ended December 31

(\$ millions)	2008	2007	Variance
Terasen Gas Companies	(261)	–	(261)
FortisAlberta	101	(76)	177
FortisBC	31	(21)	52
Newfoundland Power	(1)	(2)	1
Corporate	(179)	124 ⁽¹⁾	(303)
Total	(309)	25	(334)

⁽¹⁾ Borrowings under the Corporation's committed credit facility during 2007 primarily related to financing, on an interim basis, the remaining \$125 million net cash purchase price of Terasen on May 17, 2007, in addition to certain acquisition costs and common share issue costs; to repay certain short-term indebtedness assumed upon the acquisition of Terasen; to finance a significant portion of the cash purchase price of the Delta Regina in August 2007; and in support of general corporate activities. Indebtedness under the credit facility was partially repaid with partial net proceeds from the \$150 million common share issue and the issuance of US\$200 million unsecured notes.

Management Discussion and Analysis

Borrowings by the utilities under credit facilities are primarily in support of their respective capital expenditure programs and/or for working capital requirements. Repayments are primarily financed through the issuance of long-term debt and/or cash from operations. From time to time, proceeds from preference share, common share and long-term debt issues are used to repay borrowings under the Corporation's committed credit facility.

Net proceeds associated with the issuance of common shares under the Corporation's share purchase and stock option plans in 2008 were \$21 million compared to \$23 million in 2007. In December 2008, the Corporation publicly issued 11.7 million common shares for gross proceeds of approximately \$300 million (\$287 million net of costs). The net proceeds were used to repay short-term debt primarily incurred to retire \$200 million of debt at Terasen that matured on December 1, 2008, and for general corporate purposes. In May 2007, the Corporation publicly issued 44.3 million common shares for gross proceeds of approximately \$1.15 billion (\$1.1 billion net of costs) to finance a significant portion of the net cash purchase price of Terasen. In January 2007, 5.17 million common shares were publicly issued for gross proceeds of approximately \$150 million (\$143 million net of costs). Partial net proceeds from the common share issue in January 2007 were used to repay indebtedness incurred under the Corporation's committed credit facility. The remainder of the net proceeds was utilized to fund equity requirements of the Corporation's regulated electric utilities in western Canada, in support of their respective capital expenditure programs, and for general corporate purposes.

During the second quarter of 2008, the Corporation issued 9.2 million First Preference Shares, Series G for gross proceeds of approximately \$230 million (\$223 million net of costs). The net proceeds were used to repay \$170 million under the Corporation's committed credit facility, to fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes.

Common share dividends were \$162 million for 2008, up \$34 million from 2007. The increase was due to an increase in the number of common shares outstanding, primarily as a result of the issuance of common shares pursuant to the Terasen acquisition in May 2007 and a higher dividend declared per common share compared to 2007. The dividend declared per common share in 2008 was \$1.01, while the dividend declared per common share in 2007 was \$0.88.

Preference share dividends increased \$8 million year over year as a result of the dividends associated with the \$230 million preference shares that were issued during the second quarter of 2008.

Contractual Obligations: Consolidated contractual obligations over the next five years and for periods thereafter, as at December 31, 2008, are outlined in the following table.

Contractual Obligations

As at December 31

(\$ millions)	Total	≤ 1 year	> 1–3 years	4–5 years	> 5 years
Long-term debt ⁽¹⁾	5,122	240	319	335	4,228
Brilliant Terminal Station ⁽²⁾	63	3	5	5	50
Gas purchase contract obligations ⁽³⁾	466	416	50	–	–
Power purchase obligations					
FortisBC ⁽⁴⁾	2,829	40	76	78	2,635
FortisOntario ⁽⁵⁾	561	45	94	99	323
Maritime Electric ⁽⁶⁾	72	52	2	2	16
Belize Electricity ⁽⁷⁾	16	4	4	2	6
Capital cost ⁽⁸⁾	400	16	41	41	302
Joint-use asset and shared service agreements ⁽⁹⁾	62	4	7	6	45
Office lease – FortisBC ⁽¹⁰⁾	19	1	4	2	12
Operating lease obligations ⁽¹¹⁾	166	18	33	29	86
Other	25	4	10	6	5
Total	9,801	843	645	605	7,708

⁽¹⁾ In prior years, TGVI received non-interest bearing repayable loans from the federal and provincial governments of \$50 million and \$25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and subject to the ability of TGVI to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVI's approved capital structure, as will TGVI's rate base, which is used in determining customer rates. The repayment criteria were met in

Management Discussion and Analysis

2008 and TGV is expected to make an \$8 million repayment on the loans in 2009 (2008 – \$6 million). As at December 31, 2008, the outstanding balance of the repayable government loans was \$61 million with \$8 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the contractual obligations table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGV's revenue deficiency deferral account and the ability of TGV to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

- ⁽²⁾ On July 15, 2003, FortisBC began operating the Brilliant Terminal Station ("BTS") under an agreement, the term of which expires in 2056, (unless the Company has earlier terminated the agreement by exercising its right, at any time after the anniversary date of the agreement in 2029, to give 36 months' notice of termination). The BTS is jointly owned by CPC/CBT and is used by the Company on its own behalf and on behalf of CPC/CBT. The agreement provides that FortisBC will pay CPC/CBT a charge related to the recovery of the capital cost of the BTS and related operating costs.
- ⁽³⁾ Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2008.
- ⁽⁴⁾ Power purchase obligations for FortisBC include the Brilliant Power Purchase Agreement (the "BPPA") as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the BTS located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.
- ⁽⁵⁾ Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The first contract provides approximately 237 GWh of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric's energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.
- ⁽⁶⁾ Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. These contracts total approximately \$72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power ("NB Power") includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new International Power Line into the United States.
- ⁽⁷⁾ Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited ("Belcogen") and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation's contractual obligations.
- ⁽⁸⁾ Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Nuclear Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.
- ⁽⁹⁾ FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also

Management Discussion and Analysis

entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

⁽¹⁰⁾ Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

⁽¹¹⁾ Operating lease obligations include certain office, warehouse, natural gas T&D asset, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro Inc.

Other Contractual Obligations: Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Pension Funding: As at December 31, 2008, the fair value of the Corporation's consolidated defined benefit pension plan assets was \$579 million compared to \$674 million as at December 31, 2007, which represented a 14 per cent decline in asset value. Details of the nature of the changes in the fair value of the plan assets are disclosed in Note 20 to the Corporation's 2008 Consolidated Financial Statements. The decrease in the fair value of the pension plan assets during 2008 was mainly driven by unfavourable market conditions during the year.

The decline in the fair value of the pension plan assets is expected to have the effect of increasing the Corporation's future consolidated defined benefit pension plan funding obligations. The amount of the increase will not be determinable until the next completion of actuarial valuations, which for Newfoundland Power, the Corporation and one of the defined benefit pension plans at Terasen is expected during 2009, related to December 31, 2008 valuation dates. The next scheduled actuarial valuations for the remaining larger defined benefit pension plans are not until December 2009 and December 2010.

Fortis expects any additional defined benefit pension plan funding requirements to be sourced primarily from a combination of cash generated from operations and amounts available for borrowing under existing credit facilities.

Based on the last completion of actuarial valuations, required defined benefit pension plan funding contributions are expected to total approximately \$17 million for 2009 and \$12 million for 2010. The level of the defined benefit pension plan funding contributions will be affected by the outcome of the December 31, 2008 actuarial valuations.

Capital Structure: The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital to allow the utilities to fund maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt, as well as investment-grade credit ratings. Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates.

The consolidated capital structure of Fortis is presented in the following table.

Capital Structure

As at December 31

	2008		2007	
	(\$ millions)	(%)	(\$ millions)	(%)
Total debt and capital lease obligations (net of cash) ⁽¹⁾	5,468	59.5	5,476	64.3
Preference shares ⁽²⁾	667	7.3	442	5.2
Common shareholders' equity	3,046	33.2	2,601	30.5
Total	9,181	100.0	8,519	100.0

⁽¹⁾ Includes long-term debt, including current portion, and short-term borrowings, net of cash

⁽²⁾ Includes preference shares classified as both long-term liabilities and equity

Management Discussion and Analysis

The improvement in the capital structure from December 31, 2007 was primarily due to a \$300 million (\$291 million net of after-tax expenses) common share issue in December 2008 and a \$230 million (\$225 million net of after-tax expenses) preference share issue in the second quarter of 2008. The capital structure was also favourably impacted by net earnings applicable to common shares, net of common share dividends, of \$83 million during 2008.

The Corporation's credit ratings are as follows:

Standard & Poor's ("S&P") DBRS	A- (long-term corporate and unsecured debt credit rating) BBB(high) (unsecured debt credit rating)

During the fourth quarter of 2008, S&P and DBRS confirmed the Corporation's unsecured corporate debt credit ratings. The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

Capital Program: The Corporation's principal businesses of regulated gas and electricity distribution are capital intensive. Capital investment in infrastructure is required to ensure continued and enhanced performance, reliability and safety of the gas and electricity systems and to meet customer growth. All costs considered to be maintenance and repairs are expensed as incurred. Costs related to replacements, upgrades and betterments of capital assets are capitalized as incurred. During 2008, approximately \$94 million in maintenance and repairs was expensed compared to approximately \$87 million during 2007. The increase year over year largely reflected inclusion of the financial results of the Terasen Gas companies for a full year in 2008.

Actual gross consolidated capital expenditures for 2008 were \$904 million, comparable to the estimate for 2008 as disclosed at December 31, 2007.

A summary of gross capital expenditures for 2008 by segment and asset category is provided in the following table.

Gross Capital Expenditures

Year Ended December 31, 2008

Year Ended December 31, 2008										
					Other Regulated Utilities – Canadian ⁽¹⁾	Total Regulated Utilities – Canadian	Regulated Utilities – Caribbean	Non- Regulated – Utility ⁽³⁾	Fortis Properties	Total ⁽⁴⁾
(\$ millions)	Terasen Gas Companies ⁽¹⁾	Fortis Alberta ⁽¹⁾⁽²⁾	Fortis BC ⁽¹⁾	Newfoundland Power ⁽¹⁾						
Generation	–	–	16	5	2	23	37	18	–	78
Transmission	93	–	47	6	14	160	16	–	–	176
Distribution	108	220	37	48	27	440	43	–	–	483
Facilities, equipment, vehicles and other	4	41	7	4	2	58	13	10	14	95
Information technology	15	41	10	4	1	71	1	–	–	72
Total	220	302	117	67	46	752	110	28	14	904

⁽¹⁾ Includes asset removal and site restoration expenditures which are permissible in rate base

⁽²⁾ Excludes payments of \$31 million made to the AESO for investment in transmission capital projects

⁽³⁾ Includes non-regulated generation, non-regulated gas utility and Corporate capital expenditures

⁽⁴⁾ Includes expenditures associated with assets under construction

Gross consolidated capital expenditures for 2009 are expected to be approximately \$1 billion. Planned capital expenditures are based on detailed forecasts of customer demand, weather, and cost of labour and materials, as well as other factors, including economic conditions, which could change and cause actual expenditures to differ from forecasts.

Management Discussion and Analysis

A summary of forecast gross capital expenditures for 2009 by segment and by asset category is provided in the following table.

Forecast Gross Capital Expenditures

Year Ending December 31, 2009

	Terasen Gas Companies ⁽¹⁾	Fortis Alberta ⁽²⁾	Fortis BC ⁽¹⁾	Newfoundland Power ⁽¹⁾	Other Regulated Utilities – Canadian ⁽¹⁾	Total Regulated Utilities – Canadian	Regulated Utilities – Caribbean	Non- Regulated – Utility ⁽³⁾	Fortis Properties	Total ⁽⁴⁾
(\$ millions)										
Generation	–	–	22	10	3	35	43	34	–	112
Transmission	160	–	66	5	2	233	17	–	–	250
Distribution	87	186	37	42	26	378	36	1	–	415
Facilities, equipment, vehicles and other	8	22	7	4	1	42	19	21	33	115
Information technology	32	84	10	4	2	132	3	–	–	135
Total	287	292	142	65	34	820	118	56	33	1,027

⁽¹⁾ Includes forecast asset removal and site restoration expenditures which are permissible in rate base

⁽²⁾ Excludes forecast payments of \$31 million to be made to the AESO for investment in transmission capital projects

⁽³⁾ Includes forecast non-regulated generation, non-regulated gas utility and Corporate capital expenditures

⁽⁴⁾ Includes forecast expenditures associated with assets under construction

The percentage breakdown of 2008 actual and 2009 forecast gross capital expenditures among growth, sustaining and other is as follows:

Gross Capital Expenditures

Year Ended December 31

(%)	Actual 2008	Forecast 2009
Growth	49	45
Sustaining ⁽¹⁾	33	31
Other ⁽²⁾	18	24
Total	100	100

⁽¹⁾ Capital expenditures required to ensure continued and enhanced performance, reliability and safety of generation and T&D assets

⁽²⁾ Related to facilities, equipment, vehicles, information technology systems and other assets

Significant capital expenditure projects in 2008 and 2009 are summarized in the table below.

Significant Capital Projects

(\$ millions)		Actual 2008 ⁽¹⁾	Forecast 2009 ⁽¹⁾	Forecast costs to complete after 2009 ⁽¹⁾	Year of expected completion
Company	Nature of project				
Terasen Gas Companies	Liquefied natural gas storage facility – Vancouver Island	47	74	93	2011
	Squamish-to-Whistler pipeline lateral and system conversion	13	16	–	2009
	Customer Information System	–	14 ⁽²⁾	– ⁽²⁾	– ⁽²⁾
	Gateway Infrastructure Project	–	15	15	2010
	Fraser River South Bank South Arm Rehabilitation Project	1	25	1	2010
FortisAlberta	Automated Meter Infrastructure technology	17	73	27	2010
FortisBC	Okanagan Transmission Reinforcement Project	3	32	100	2011
	New substations and associated transmission lines	27	16	73	2013
	Generation asset Upgrade and Life-Extension Program	11	14	39	2012
Caribbean Utilities	New 16-MW diesel-fired generating unit	8	21	–	2009
Non-Regulated – Fortis Generation	19-MW Vaca hydroelectric generating facility in Belize	18	34	–	Beginning of 2010
Fortis Properties	Expansion of Holiday Inn Express Kelowna	2	12	–	Beginning of 2010

⁽¹⁾ Includes allowance for funds used during construction

⁽²⁾ The total cost and timing of the project are subject to regulatory approval. An application requesting approval of the project is expected in 2009.

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In April 2008, TGI received approval from the BCUC to proceed with the engineering, procurement and construction (“EPC”) of the liquefied natural gas (“LNG”) storage facility on Vancouver Island for a total cost of approximately \$200 million. As a result, the Company entered into an EPC contract with a third party for the construction of the facility. The contract includes approximately \$55 million to be paid in US dollars. As a result, TGI entered into a three-year US dollar forward-purchase contract which will mitigate currency fluctuations on the US dollar portion of the EPC contract. Construction commenced on the LNG storage facility during the second quarter of 2008 with completion of the project expected in late 2011.

TGI's construction of a 50-kilometre pipeline lateral from Squamish to Whistler continued in 2008 and, as at December 31, 2008, approximately 49 kilometres of the pipeline had been constructed. Originally scheduled to be completed by summer 2008, the pipeline lateral is now expected to be completed in April 2009, later than originally planned due to changes in the way the Company can sequence the pipeline construction as a result of the Government of British Columbia's Sea-to-Sky Highway Improvement Project Plan (“Highway Project”). The pipeline is being built in conjunction with the Highway Project and the pipeline route mainly falls within the highway right of way. Upon completion of the pipeline, the Company will convert the Resort Municipality of Whistler from propane to natural gas during spring and summer of 2009. The total cost of the pipeline lateral and system conversion is expected to be approximately \$51 million.

TGI is currently conducting a review of the existing customer care services arrangements with its outsourced provider to ensure the needs of customers will be met in the future. Later in 2009, TGI expects to file an application with the BCUC requesting approval and funding for the development of a replacement customer information system with capital spending related to this project estimated at \$14 million for 2009.

As a result of the Government of British Columbia's Gateway Initiative, a regional infrastructure program to improve the movement of people, goods and transit throughout Greater Vancouver, TGI will be required to relocate some of its pipeline system. Total capital spending for the project, which is expected to be fully funded from contributions from the Government of British Columbia, is estimated at approximately \$30 million, with \$15 million expected to be spent in 2009.

In the fourth quarter of 2008, TGI filed an application with the BCUC requesting approval to perform extensive rehabilitation of certain underwater transmission pipeline crossings of the South Arm of the Fraser River serving Vancouver and Richmond. TGI expects to receive approval for this project in early 2009 with completion of the project anticipated in 2010. The total capital cost of the project is anticipated to be approximately \$27 million.

During the third quarter of 2008, FortisAlberta began the second phase of deployment of the replacement of conventional meters with new Automated Meter Infrastructure (“AMI”) technology. This phase is part of an overall \$124 million project to convert all of FortisAlberta's customers to AMI technology over a four-year period that began in 2007.

In October 2008, the BCUC approved FortisBC's proposed \$141 million Okanagan Transmission Reinforcement Project, which was included in FortisBC's 2009 and 2010 Capital Expenditure Plan. The project relates to upgrading the existing overhead transmission line from 161 kilovolts (“kV”) to 230 kV from Vaseux Lake to Oliver and Penticton and building a new 230-kV transmission line from Vaseux Lake to Penticton and a substation. FortisBC anticipates that construction of the project will begin in spring 2009 for expected completion in 2011.

During 2008, work continued at FortisBC on a number of new substations and associated transmission lines. Approximately 82 per cent of capital expenditures after 2009 related to this project are subject to regulatory approval.

Since 1998, FortisBC's hydroelectric generating facilities have been subject to an Upgrade and Life-Extension Program which is forecast to conclude in 2012. Approximately 57 per cent of capital expenditures after 2009 related to this project are subject to regulatory approval.

In April 2008, Caribbean Utilities entered into an agreement to purchase a 16-MW diesel generating unit and related equipment from a supplier in Germany for approximately US\$24 million over the period 2008 and 2009, with the unit scheduled for completion in September 2009.

Construction continued in 2008 on the US\$53 million 19-MW hydroelectric generating facility at Vaca on the Macal River in Belize. The facility is being constructed downstream from the Chalillo and Mollejon hydroelectric generating facilities and is expected to increase average annual energy production from the Macal River by approximately 80 GWh to 240 GWh. The facility is expected to come into service at the beginning of 2010, slightly later than originally planned due to labour and weather-related delays.

Management Discussion and Analysis

Late in 2008, Fortis Properties commenced the expansion of its Holiday Inn Express Kelowna hotel which includes adding 70 rooms and 4,000 square feet of meeting room space. Completion of the expansion is expected by January 2010 at a total capital cost of approximately \$14 million.

Over the next five years, consolidated gross capital expenditures are expected to total approximately \$4.5 billion. Approximately \$3.1 billion of the capital spending is expected to be incurred at the regulated electric utilities, driven by FortisAlberta, FortisBC and the Corporation's regulated utility operations in the Caribbean. Approximately \$1.2 billion is expected to be incurred at the regulated gas utilities. Capital expenditures at the regulated utilities are subject to regulatory approval. Non-regulated capital expenditures are expected to total approximately \$200 million over the same period.

Cash Flow Requirements: At the operating subsidiary level, it is expected that operating expenses and interest costs will generally be paid out of subsidiary operating cash flows, with varying levels of residual cash flow available for subsidiary capital expenditures and/or dividend payments to Fortis. Borrowings under credit facilities may be required from time to time to support seasonal working capital requirements. Cash required to complete subsidiary capital expenditure programs is also expected to be financed from a combination of borrowings under credit facilities, equity injections from Fortis and long-term debt issues.

The Corporation's ability to service its debt obligations and pay dividends on its common shares and preference shares is dependent on the financial results of the operating subsidiaries and the related cash payments from these subsidiaries. Certain regulated subsidiaries may be subject to restrictions which may limit their ability to distribute cash to Fortis. Cash required of Fortis to support subsidiary capital expenditure programs and finance acquisitions is expected to be derived from a combination of borrowings under its committed credit facility and proceeds from the issuance of common shares, preference shares and long-term debt. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends.

The Corporation does not expect any significant decrease in subsidiary operating cash flows in 2009 as a result of the anticipated continued downturn in the global economy. The subsidiaries expect to be able to source the cash required to fund their 2009 capital expenditure programs.

Management expects consolidated long-term debt maturities and repayments to be approximately \$240 million in 2009 and to average approximately \$180 million annually over the next five years. The combination of available credit facilities, as discussed in more detail below, and low annual debt maturities and repayments will provide the Corporation and its subsidiaries with flexibility in the timing of access to the capital markets. For a discussion of capital resources and liquidity risk, refer to the "Business Risk Management – Capital Resources and Liquidity Risk" section of this MD&A.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 Rate Application, Belize Electricity does not meet certain debt covenant financial ratios related to loans with the International Bank for Reconstruction and Development and the Caribbean Development Bank totalling \$11 million (BZ\$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

As a result of legislation passed in 2008 by the Government of Newfoundland and Labrador expropriating most of the Newfoundland assets of Abitibi-Consolidated, the Exploits Partnership is potentially in default of a \$61 million term loan. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The term loan, which is non-recourse to Fortis, has been reclassified to current portion of long-term debt on the consolidated balance sheet as at December 31, 2008. A further discussion of the Exploits Partnership is provided in the "Critical Accounting Estimates – Contingencies" section of this MD&A.

Fortis and its subsidiaries, except for Belize Electricity and debt associated with the Exploits Partnership as described above, were in compliance with debt covenants as at December 31, 2008 and are expected to remain compliant in 2009.

Credit Facilities: As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of \$2.2 billion, of which approximately \$1.5 billion was unused, including \$568 million unused under the Corporation's \$600 million committed revolving credit facility. The credit facilities are syndicated almost entirely with the seven largest Canadian banks, with no one bank holding more than 25 per cent of these facilities.

Approximately \$2.0 billion of the total credit facilities are committed facilities, the majority of which have maturities between 2011 and 2013.

Management Discussion and Analysis

In 2009, FortisBC expects to have the term of its committed \$100 million 364-day revolving credit facility extended for a further year beyond its original maturity in May 2009. Terasen Inc. expects to renew its \$100 million committed revolving credit facility, which matures in May 2009. In March 2009, Maritime Electric renegotiated its \$50 million demand credit facility and had it converted into a 364-day revolving committed credit facility.

The cost of renewed and extended credit facilities may increase as a result of current economic conditions and tightened credit markets; however, any increased interest expense and/or fees is not expected to have a material financial impact on the Corporation and its subsidiaries in 2009 as the majority of the committed credit facilities have maturities beyond 2009.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

Credit Facilities

As at December 31 (\$ millions)	Corporate and Other	Regulated Utilities	Fortis Properties	Total 2008	Total 2007
Total credit facilities	715	1,500	13	2,228	2,234
Credit facilities utilized					
Short-term borrowings	—	(410)	—	(410)	(475)
Long-term debt	(32)	(192)	—	(224)	(530)
Letters of credit outstanding	(1)	(102)	(1)	(104)	(159)
Credit facilities available	682	796	12	1,490	1,070

At December 31, 2008 and December 31, 2007, certain borrowings under the Corporation's and subsidiaries' credit facilities were classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Significant changes in total credit facilities from December 31, 2007 to December 31, 2008 are described below. The nature and terms of the credit facilities outstanding as at December 31, 2008 are detailed in Note 26 to the 2008 Consolidated Financial Statements.

Corporate and Other

Letters of credit of \$50 million previously outstanding at Terasen Inc., related to its previously owned petroleum transportation business and secured by a letter of credit from the former parent company, were cancelled during the second quarter of 2008.

Regulated Utilities

In April 2008, FortisBC renegotiated and amended its \$150 million unsecured committed revolving credit facility, extending the maturity date of the \$50 million portion of the facility to May 2011 from May 2010 and extending the \$100 million portion to May 2009 from May 2008. The Company has the option to increase the credit facility to an aggregate of \$200 million, subject to bank approval.

In April 2008, Maritime Electric repaid all outstanding borrowings under its \$25 million unsecured credit facility with partial proceeds from a \$60 million bond issue. The credit facility matured in May 2008 and was not renewed.

In July 2008, TGI renegotiated, on substantially similar terms, its \$500 million unsecured committed revolving credit facility, extending the maturity date of the facility to August 2013 from August 2012.

In August 2008, Newfoundland Power renegotiated, on substantially similar terms, its \$100 million committed revolving credit facility, extending the maturity date to August 2011 from January 2009.

In November 2008, First Caribbean International Bank withdrew its credit facility with Belize Electricity, requiring the Company to repay approximately BZ\$4 million outstanding under the facility. Scotiabank has also put Belize Electricity on notice that it may not renew its BZ\$5 million credit facility with the Company if financial conditions do not show signs of improvement. As at December 31, 2008, the Scotiabank credit facility was undrawn. A continuation of lower energy supply costs should provide Belize Electricity with some liquidity relief in the near term.

Management Discussion and Analysis

Off-Balance Sheet Arrangements

As at December 31, 2008, the Corporation had no off-balance sheet arrangements such as transactions, agreements or contractual arrangements with unconsolidated entities, structured finance entities, special purpose entities or variable interest entities that are reasonably likely to materially affect liquidity or the availability of, or requirements for, capital resources.

Business Risk Management

The following is a summary of the Corporation's significant business risks.

Regulatory Risk: The Corporation's key business risk is regulation. Each of the Corporation's regulated utilities is subject to some form of regulation that can affect future revenue and earnings. Management at each utility is responsible for working closely with regulators and local governments to ensure both compliance with existing regulations and the proactive management of regulatory issues.

Approximately 93 per cent of the Corporation's operating revenue was derived from regulated utility operations in 2008 (2007 – 90 per cent), while approximately 83 per cent of the Corporation's operating earnings, before corporate and other net expenses, were derived from regulated utility operations in 2008 (2007 – 81 per cent). The regulated utilities, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity, Caribbean Utilities, and Fortis Turks and Caicos, are subject to the normal uncertainties faced by regulated entities. The uncertainties include approvals by the respective regulatory authorities of gas and electricity rates that permit a reasonable opportunity to recover, on a timely basis, the estimated costs of providing services, including a fair rate of return on rate base. Generally, the ability of the utilities to recover the actual costs of providing services and earn the approved rates of return depends on achieving the forecasts established in the rate-setting processes. Upgrades of existing gas and electricity systems and facilities and the addition of new infrastructure and facilities require the approval of the regulatory authorities either through the approval of capital expenditure plans or through regulatory approval of revenue requirements for the purpose of setting rates, which include the impact of capital expenditures on rate base and/or cost of service. There is no assurance that capital projects perceived as required or completed by the Corporation's regulated utilities will be approved or that conditions to such approvals will not be imposed. Capital cost overruns subject to such approvals might not be recoverable. In addition, there is no assurance that the regulated utilities will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures, as well as pursued through public hearing processes. There can be no assurance that rate orders issued will permit the Corporation's utilities to recover all costs actually incurred and to earn the expected rates of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by the utilities, the undertaking or timing of proposed capital projects, ratings assigned by rating agencies, the issuance and sale of securities, and other matters which may, in turn, negatively affect the results of operations and financial position of the Corporation's utilities.

Although Fortis considers the regulatory frameworks in most of the jurisdictions it operates in to be fair and balanced, uncertainties do exist at the present time. The June 2008 regulatory decision on Belize Electricity's 2008/2009 Rate Application and changes in electricity legislation made by the Government of Belize and the PUC create uncertainty in the regulatory regime and the rate-setting process in Belize and violate both established regulatory practice and contractual obligations made by the Government of Belize at the time Fortis made its initial investment in Belize Electricity.

Regulatory frameworks in Alberta and Ontario have undergone significant changes since the deregulation of electricity generation and the introduction of retail competition. The regulations and market rules in these jurisdictions, which govern the competitive wholesale and retail electricity markets, are relatively new and there may be significant changes in these regulations and market rules that could adversely affect the ability of FortisAlberta and FortisOntario to recover costs or to earn reasonable returns on capital. As these companies and their applicable regulators work through the regulatory processes, it is expected that there will be more certainty in evolving regulatory frameworks and environments.

Although all of the Corporation's regulated utilities currently operate under traditional cost of service and/or rate of return on rate base methodologies, PBR and other rate-setting mechanisms, such as automatic rate of return formulas, are also being employed to varying degrees. A discussion of the impact of changes in interest rates on allowed ROEs is provided in the "Business Risk Management – Interest Rate Risk" section of this MD&A.

Management Discussion and Analysis

TGI, TGV and FortisBC are regulated by the BCUC and are subject to approved PBR mechanisms. The PBR mechanisms at TGI and TGV expire in 2009. In December 2008, the PBR mechanism at FortisBC was extended for the periods from 2009 to 2011 under terms similar to the previous PBR agreement, except annual gross operating and maintenance expenses, before capitalized overhead, will be set by a different formula. The PBR mechanisms provide the utilities an opportunity to earn returns in excess of the allowed ROEs determined by the BCUC. Upon expiry of the PBR mechanisms, there is no certainty as to whether new PBR mechanisms will be entered into or what the particular terms of any renewed PBR mechanisms will be.

Further information on the new PBR mechanism at FortisBC and the nature of regulation and various regulatory matters pertaining to the Corporation's utilities is provided in the "Regulatory Highlights" section of this MD&A.

Operating and Maintenance Risks: The Terasen Gas companies are exposed to various operational risks, such as pipeline leaks; accidental damage to, or fatigue cracks in mains and service lines; corrosion in pipes; pipeline or equipment failure; other issues that can lead to outages and/or leaks; and any other accidents involving natural gas which could result in significant operational and/or environmental liability. The business of electricity transmission and distribution is also subject to operational risks including the potential to cause fires, mainly as a result of equipment failure, falling trees and lightning strikes to lines or equipment. The infrastructure of the subsidiaries is also exposed to the effects of severe weather conditions and other acts of nature. In addition, a significant portion of the infrastructure is located in remote areas, which may make access difficult for repair of damage due to weather conditions and other acts of nature. The Terasen Gas companies and FortisBC operate facilities in a terrain with a risk of loss or damage from earthquakes, forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Corporation and its subsidiaries have insurance that provides coverage for business interruption, liability and property damage, although the coverage offered by this insurance is limited. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the respective regulatory authority for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the regulatory authorities would approve any such application in whole or in part. See the "Business Risk Management – Insurance Coverage Risk" section of this MD&A for a further discussion on insurance.

The Corporation's gas and electricity systems require ongoing maintenance, improvement and replacement. Accordingly, to ensure the continued performance of the physical assets, the utilities determine expenditures that must be made to maintain and replace the assets. If the systems are not able to be maintained, service disruptions and increased costs may be experienced. The inability to obtain regulatory approval to reflect in rates the expenditures the utilities believe are necessary to maintain, improve and replace their assets; the failure by the utilities to properly implement or complete approved capital expenditure programs; or the occurrence of significant unforeseen equipment failures, despite maintenance programs, could have a material effect on the operations of the utilities.

The Corporation's utilities continually develop capital expenditure programs and assess current and future operating and maintenance expenses that will be incurred in the ongoing operation of their gas and electricity systems. Management's analysis is based on assumptions as to costs of services and equipment, regulatory requirements, revenue requirement approvals, and other matters, which involve some degree of uncertainty. If actual costs exceed regulator-approved capital expenditures, it is uncertain as to whether any additional costs will receive regulatory approval for recovery in future customer rates. The inability to recover these additional costs could have a material effect on the financial condition and results of operations of the utilities.

Economic Conditions: Typical of utilities, economic conditions in the Corporation's service territories influence energy sales. Energy sales are influenced by economic factors such as changes in employment levels, personal disposable income, energy prices and housing starts. Also, in the service territories in which the Terasen Gas companies operate, the growth of new multi-family housing starts is continuing to outpace that of new single-family housing starts. Natural gas has a lower penetration rate in multi-family housing; therefore, gas distribution volumes may not grow as quickly as in the past. In the Caribbean, the level of and fluctuations in tourism and related activities, which are closely tied to economic conditions, influence electricity sales as they affect electricity demand of the large hotels and condominium complexes that are serviced by the Corporation's regulated utilities in that region.

Higher energy prices can result in reduced consumption by customers. Natural gas and crude oil exploration and production activity in certain of the Corporation's service territories are closely correlated with natural gas and crude oil prices. The level of these activities can influence energy demand.

An extended decline in economic conditions would be expected to have the effect of reducing demand for energy over time. The regulated nature of utility operations, including various mitigating measures approved by regulators, helps to reduce the impact that lower energy demand, associated with poor economic conditions, may have on the utilities' earnings. However, a severe and prolonged downturn in economic conditions could materially affect the utilities, despite regulatory measures available for compensating for reduced demand. For instance, significantly reduced energy demand in the Corporation's service territories could reduce capital spending which would, in turn, impact rate base and earnings' growth.

Management Discussion and Analysis

In addition to the impact of reduced energy demand, an extended decline in economic conditions could also impair the ability of customers to pay for gas and electricity consumed, thereby affecting the aging and collection of the utilities' trade receivables.

Fortis also holds investments in both commercial real estate and hotel properties. The hotel properties, in particular, are subject to operating risks associated with industry fluctuations and local economic conditions. Fortis Properties' real estate exposure to lease expiries averages approximately 11 per cent per annum over the next five years. Approximately 57 per cent of Fortis Properties' operating income was derived from hotel investments in 2008 (2007 – 58 per cent). Achieving organic revenue and earnings' growth at the Hospitality Division may prove challenging in 2009 as a result of the anticipated continued downturn in the global economy and its overall impact on leisure and business travel and hotel stays. It is estimated that a 10 per cent decrease in revenue at the Hospitality Division would decrease annual basic earnings per common share of Fortis by approximately 2 cents.

Capital Resources and Liquidity Risk: The Corporation's financial position could be adversely affected if it, or its subsidiaries, fails to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and the financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions. Funds generated from operations after payment of expected expenses (including interest payments on any outstanding debt) will not be sufficient to fund the repayment of all outstanding liabilities when due as well as all anticipated capital expenditures. There can be no assurance that sufficient capital will continue to be available on acceptable terms to fund capital expenditures and to repay existing debt.

Generally, the Corporation and its currently rated regulated utilities are subject to financial risk associated with changes in the credit ratings assigned to them by credit rating agencies. Credit ratings affect the level of credit risk spreads on new long-term debt issues and on the Corporation's and its utilities' credit facilities. A change in the credit ratings could potentially affect access to various sources of capital and increase or decrease the finance charges of the Corporation and its utilities. Also, a significant downgrade in TGI or Terasen Inc.'s credit ratings could trigger margin calls and other cash requirements under TGI's natural gas purchase and natural gas derivative contracts. As discussed in the "Liquidity and Capital Resources – Capital Structure" section of this MD&A, the Corporation's corporate investment-grade credit ratings were confirmed and maintained during the fourth quarter of 2008. Fortis and its regulated utilities do not anticipate any material adverse rating actions by the credit rating agencies in the near term. However, the current global financial crisis has placed increased scrutiny on rating agencies and rating agency criteria which may result in changes to credit rating practices and policies.

The volatility in the global financial and capital markets may increase the cost of, and affect the timing of, issuance of long-term capital by the Corporation and its utilities in 2009. While the cost of borrowing is expected to increase, as new long-term debt is expected to be issued at higher rates due to an increase in credit spreads, the Corporation and its utilities expect to continue to have reasonable access to capital in the near to medium terms. Due to the regulated nature of the Corporation's utilities, increased borrowing costs are eligible to be recovered in future customer rates.

To help mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements. The committed credit facility at the Corporation is available for interim financing of acquisitions and for general corporate purposes. The cost of renewed and extended credit facilities may also increase going forward; however, any increased interest expense and/or fees is not expected to have a material financial impact on the Corporation and its utilities in 2009 as the majority of the total committed credit facilities have maturities beyond 2009.

Further information about the Corporation's credit facilities, contractual obligations, including long-term debt maturities and repayments, and consolidated cash flow requirements is provided in the "Liquidity and Capital Resources" section of this MD&A and under "Liquidity Risk" in Note 26 to the 2008 Consolidated Financial Statements.

Weather and Seasonality: The physical assets of the Corporation and its subsidiaries are exposed to the effects of severe weather conditions and other acts of nature. Although the physical assets have been constructed and are operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. At Newfoundland Power, exposure to climatic factors is addressed through the operation of a regulator-approved weather normalization reserve. The operation of this reserve mitigates year-to-year volatility in earnings that would otherwise be caused by variations in weather conditions. At TGI, a BCUC-approved rate stabilization account serves to mitigate the effect on earnings of volume volatility, caused principally by weather, by allowing TGI to accumulate the margin impact of variations in the actual-versus-forecast gas volumes consumed by customers.

Management Discussion and Analysis

At the Terasen Gas companies, weather has a significant impact on distribution volume, as a major portion of the gas distributed is ultimately used for space heating for residential customers. Because of gas-consumption patterns, the Terasen Gas companies normally generate quarterly earnings that vary by season and may not be an indicator of annual earnings. Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters.

Fluctuations in the amount of electricity used by customers can vary significantly in response to seasonal changes in weather. In Canada, cool summers may reduce air-conditioning demand while warm winters may reduce electric heating load. In the Caribbean, the impact of seasonal changes in weather on air-conditioning demand is less pronounced due to less variable climatic conditions that exist in the region. Significant fluctuations in weather-related demand for electricity could materially impact the operations, financial condition and results of operations of the electric utilities.

Despite preparation for severe weather, extraordinary conditions such as hurricanes and other natural disasters will always remain a risk to utilities. The Corporation uses a centralized insurance management function to create a higher level of insurance expertise and reduce its liability exposure.

The assets and earnings of Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos are subject to hurricane risk. Similar to other Fortis utilities, these companies manage weather risks through insurance on generation assets, business-interruption insurance and self-insurance on T&D assets. In Belize, additional costs in the event of a hurricane would be deferred and the Company may apply for future recovery in customer rates. Under its new T&D licence, Caribbean Utilities may apply for a special additional customer rate in the event of a disaster, including a hurricane. Fortis Turks and Caicos does not have a specific hurricane cost recovery mechanism; however, the Company may apply for an increase in customer rates in the following year if the actual ROA is lower than the allowed ROA due to additional costs resulting from a hurricane or other significant event.

Earnings from non-regulated generation assets are sensitive to rainfall levels but the geographic diversity of the Corporation's generation assets mitigates the risk associated with rainfall levels.

Commodity Price Risk: The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. The companies employ a number of tools to reduce exposure to natural gas price volatility. These tools include purchasing gas for storage and adopting hedging strategies to reduce price volatility and ensure, to the extent possible, that natural gas commodity costs remain competitive with electricity rates. The use of natural gas derivatives effectively fixes the price of natural gas purchases. Activities related to the hedging of gas prices are currently approved by the BCUC and gains or losses effectively accrue entirely to customers. The operation of BCUC-approved rate stabilization accounts to flow through in customer rates the commodity cost of natural gas serves to mitigate the effect on earnings of natural gas cost volatility.

Most of the Corporation's regulated electric utilities are exposed to commodity price risk associated with changes in world oil prices, which affects the cost of fuel and purchased power. The risk is substantially mitigated through the utilities' ability to flow through to customers the cost of fuel and purchased power through basic rates and/or through the use of rate-stabilization and other mechanisms, as approved by the various regulatory authorities. The ability to flow through to customers the cost of fuel and purchased power alleviates the effect on earnings of the variability in the cost of fuel and purchased power.

There can be no assurance that the current regulator-approved mechanisms allowing for the flow through of the cost of natural gas, fuel and purchased power will continue to exist in the future. An inability of the regulated utilities to flow through the full cost of natural gas, fuel and/or purchased power could materially affect the utilities' results of operations, financial position and cash flows.

Derivative Financial Instruments and Hedging: From time to time, the Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas commodity prices through the use of derivative financial instruments. The derivative financial instruments, such as interest rate swap contracts, foreign exchange future contracts and natural gas commodity swaps and options, are used by the Corporation and its subsidiaries only to manage risk. The Corporation and its subsidiaries do not hold or issue derivative financial instruments for trading purposes. All derivative financial instruments must be measured at fair value. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates.

Management Discussion and Analysis

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ\$2.00 = US\$1.00. The Corporation has also designated all of its US\$403 million corporately held US dollar-denominated long-term debt as a hedge of a portion of the Corporation's foreign net investments. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income. As at December 31, 2008, the Corporation had approximately US\$119 million in foreign net investments remaining to be hedged.

Interest Rate Risk: Generally, allowed returns for regulated utilities in North America are exposed to changes in the general level of long-term interest rates. Earnings of such regulated utilities are exposed to changes in long-term interest rates associated with rate-setting mechanisms. The rate of return is affected either directly through automatic adjustment mechanisms or indirectly through regulatory determinations of what constitutes an appropriate rate of return on investment. Automatic adjustment mechanisms currently apply to the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power. Due to a decline in long-term Canada bond yields during 2008 and the operation of the automatic adjustment mechanisms, the allowed ROEs for TGI and FortisBC have been reset for 2009. The 2008 allowed ROEs for the Corporation's four largest utilities, TGI, FortisAlberta, FortisBC and Newfoundland Power, were 8.62 per cent, 8.75 per cent, 9.02 per cent and 8.95 per cent, respectively. Effective January 1, 2009, the allowed ROEs for TGI and FortisBC have decreased to 8.47 per cent and 8.87 per cent, respectively, while the allowed ROE for Newfoundland Power remains unchanged at 8.95 per cent. FortisAlberta is currently engaged in a Generic Cost of Capital Proceeding with its regulator to review, among other things, 2009 ROE calculations and capital structures for regulated gas, electric and pipeline utilities in Alberta. In the interim, as directed by its regulator, customer rates for 2009 for FortisAlberta have been set using the utility's 2007 allowed ROE of 8.51 per cent. The National Energy Board is also undertaking a review of existing ROE levels.

A continuation of current ROE adjustment mechanisms combined with declining long-term Canada bond yields, in an environment where the cost of capital is increasing, could materially affect the ability of the Corporation's utilities to earn reasonable ROEs, the absence of which could negatively impact the regulated utilities' financial condition, results of operations and cash flows.

The Corporation and its subsidiaries are also exposed to interest rate risk associated with short-term borrowings and floating rate debt. However, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest rate expense resulting from fluctuations in interest rates associated with variable rate debt for recovery from, or refund to, customers in future rates. As described in the "Business Risk Management – Derivative Financial Instruments and Hedging" section of this MD&A, the Corporation and its subsidiaries may also enter into interest rate swap agreements from time to time to help reduce interest rate risk.

As at December 31, 2008, approximately 84 per cent of the Corporation's consolidated long-term debt facilities and capital lease obligations had maturities beyond five years. With a significant portion of the Corporation's consolidated debt having long-term maturities, interest rate risk on debt refinancing has been reduced for the near and medium terms.

The following table outlines the nature of the Corporation's consolidated debt at December 31, 2008.

Total Debt

As at December 31, 2008

	(\$ millions)	(%)
Short-term borrowings	410	7.4
Utilized variable-rate credit facilities classified as long-term	224	4.0
Variable-rate long-term debt and capital lease obligations (including current portion)	22	0.4
Fixed-rate long-term debt and capital lease obligations (including current portion)	4,878	88.2
Total	5,534	100.0

Management Discussion and Analysis

A change in the level of interest rates could materially affect the measurement and recording of changes in the fair value of interest rate swaps. The impact of a material change in interest rates on the fair value measurement of the interest rate swaps outstanding as at December 31, 2008 is not expected to materially affect the Corporation's consolidated earnings and comprehensive income due to the low notional value of the interest rate swaps and their near-term maturities.

The nature and fair value of the interest rate swaps outstanding as at December 31, 2008 is provided in the "Financial Instruments" section of this MD&A. A sensitivity analysis of a change in interest rates as that change would have affected 2008 financial results is disclosed in Note 26 to the 2008 Consolidated Financial Statements.

It is estimated that a 6 cent, or 5 per cent, increase (decrease) in the US dollar-to-Canadian dollar exchange rate from the exchange rate of 1.22, as at December 31, 2008, would increase (decrease) basic earnings per common share of Fortis by 1 cent in 2009.

Management will continue to hedge future exchange rate fluctuations related to the Corporation's foreign net investments and US dollar and Belizean dollar earnings' streams, where possible, through future US dollar borrowings and will continue to monitor the Corporation's exposure to foreign currency fluctuations on a regular basis.

Counterparty Risk: The Terasen Gas companies are exposed to credit risk in the event of non-performance by counterparties to derivative financial instruments. The Terasen Gas companies are also exposed to significant credit risk on physical off-system sales. The Terasen Gas companies deal with high credit-quality institutions in accordance with established credit approval practices. Due to recent events in the capital markets, including significant government intervention in the banking system, the Terasen Gas companies have further limited the financial counterparties they transact with and have reduced available credit to, or taken additional security from, the physical off-system sales counterparties with which they transact. To date, the Terasen Gas companies have not experienced any counterparty defaults and they do not expect any counterparties to fail to meet their obligations; however, the credit quality of counterparties, as recent events have indicated, can change rapidly.

FortisAlberta is exposed to credit risk associated with sales to retailers. Significantly all of FortisAlberta's distribution-service billings are to a relatively small group of retailers. As required under regulation, FortisAlberta minimizes its credit exposure associated with retailer billings by obtaining from the retailer a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency, or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating. See also the "Business Risk Management – Economic Conditions" section of this MD&A.

Competitiveness of Natural Gas: In recent years, the price of natural gas has been only marginally lower than the comparable price for electricity for residential customers in British Columbia, especially on Vancouver Island. There is no assurance that natural gas will continue to maintain a competitive price advantage in the future. If natural gas pricing becomes uncompetitive with electricity pricing or pricing for alternative energy sources, the ability of the Terasen Gas companies to add new customers could be impaired and existing customers could reduce their consumption of natural gas or eliminate its usage altogether as furnaces, water heaters and other appliances are replaced. This may result in higher rates and, in an extreme case, could ultimately lead to an inability to fully recover the cost of service of the Terasen Gas companies in rates charged to customers. The ability of the Terasen Gas companies to add new customers and increase sales volumes could also be affected by lower prices of other competitive energy sources, as some commercial and industrial customers have the ability to switch to an alternative fuel. See also the "Business Risk Management – Government of British Columbia's Energy Plan" and "Business Risk Management – Risks Related to TGV" sections of this MD&A.

Natural Gas Supply: The Terasen Gas companies are dependent on a limited number of pipeline and storage providers, particularly in the Vancouver, Fraser Valley and Vancouver Island service areas where the majority of the natural gas distribution customers of the Terasen Gas companies are located. Regional market prices have been higher from time to time than prices elsewhere in North America, as a result of insufficient seasonal and peak storage and pipeline capacity to serve the increasing demand for natural gas in British Columbia and the US Pacific Northwest. In addition, the Terasen Gas companies are critically dependent on a single-source transmission pipeline. In the event of a prolonged service disruption of the Spectra Pipeline System, residential customers of the Terasen Gas companies could experience outages, thereby affecting revenue and incurring costs to safely relight customers.

Defined Benefit Pension Plan Performance and Funding Requirements: Each of Terasen, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Caribbean Utilities and Fortis maintain defined benefit pension plans for certain of their employees; however, only 61 per cent of the above utilities' total employees are members of such plans. The recent volatility in the global financial and capital markets is expected to affect the Corporation's consolidated future defined benefit pension funding requirements, as discussed in the "Liquidity and Capital Resources – Pension Funding" section of this MD&A. Future pension benefit

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obligations and related pension expense may also be affected. The Corporation's and subsidiaries' defined benefit pension plans are subject to judgments utilized in the actuarial determination of the accrued pension benefit obligation and related pension expense. The primary assumptions utilized by management are the expected long-term rate of return on pension plan assets and the discount rate used to value the accrued pension benefit obligation. A discussion of the critical accounting estimates associated with defined benefit pension plans is provided in the "Critical Accounting Estimates – Employee Future Benefits" section of this MD&A.

There is no assurance that the pension plan assets will earn the assumed long-term rates of return in the future. With the exception of Newfoundland Power and Terasen, the pension plan assets are valued at fair value. At Newfoundland Power and Terasen, the pension plan assets are valued using the market-related value as disclosed in Note 2 to the 2008 Consolidated Financial Statements. Market-driven changes impacting the performance of the pension plan assets may result in material variations in actual return on pension plan assets from the assumed long-term return on the assets. This may cause material changes in future pension funding requirements from current estimates and material changes in future pension expense.

Market-driven changes impacting the discount rate, which is used to value the accrued pension benefit obligation as at the measurement date of each of the defined benefit pension plans, may result in material changes in future pension funding requirements from current estimates and material changes in future pension expense.

There is also risk associated with measurement uncertainty inherent in the actuarial valuation process as it affects the measurement of pension expense, future funding requirements, the accrued benefit asset, accrued benefit liability and benefit obligation.

The above risks are mitigated as any increase or decrease in future pension funding requirements and/or pension expense at the regulated utilities is expected to be recovered from, or refunded to, customers in future rates, subject to forecast risk. At the Terasen Gas companies and FortisBC, however, actual pension expense above or below the forecast pension expense approved for recovery in customer rates for the year is subject to deferral account treatment for recovery from, or refund to, customers in future rates, subject to regulatory approval. Also mitigating the above risks is the fact that the defined benefit pension plans at FortisAlberta and Newfoundland Power are closed to all new employees.

Risks Related to TGVI: TGVI is a franchise under development in the price-competitive service area of Vancouver Island, with a customer base and revenue that is insufficient to meet the Company's current cost of service and to recover revenue deficiencies from prior years. Recovery of accumulated revenue deficiencies from prior years puts gas at a cost disadvantage relative to electricity. To assist with competitive rates during franchise development, the Vancouver Island Natural Gas Pipeline Agreement ("VINGPA") provides royalty revenues from the Government of British Columbia which currently cover approximately 20 per cent of the current cost of service. These revenues are due to expire at the end of 2011, after which time TGVI's customers will be required to absorb the full commodity cost of gas, all other costs of service and the recovery of any remaining accumulated revenue deficiencies. When VINGPA expires in 2011, the remaining amount outstanding under non-interest bearing senior government loans, which is currently treated as a government contribution against rate base, will be required to be fully repaid. As at December 31, 2008, the balance outstanding under these loans was \$61 million. As the debt is repaid, the cost of the higher rate base will increase the cost of service and customer rates, making gas less competitive with electricity on Vancouver Island.

Government of British Columbia's Energy Plan: The Government of British Columbia released its Energy Plan in February 2007. The Energy Plan is a progression from the previous plan with a focus on environmental leadership, energy conservation and efficiency, and investing in innovation. The Energy Plan outlines various measures to address the challenges of global warming including that all electricity produced in British Columbia will be required to have zero net greenhouse gas emissions by 2016. The Energy Plan places a significant responsibility on British Columbians to conserve energy by requiring 50 per cent of British Columbia's incremental resource needs to be achieved through conservation by 2020. The Energy Plan emphasizes efficiency by requiring BC Hydro to eliminate electricity imports and become fully self-sufficient by 2016. The Energy Plan also states that 90 per cent of British Columbia's electricity will come from renewable sources and that British Columbia will become the first jurisdiction in North America to require 100 per cent carbon sequestration for any coal-fired electricity project. FortisBC and the Terasen Gas companies continue to assess the impacts and opportunities provided by the Energy Plan and will consider which policy actions they may support. Many of the principles of the Energy Plan were adopted when *Bill 15-2008, the Utilities Commission Amendment Act, 2008*, received Royal Assent by the Legislative Assembly of British Columbia on May 1, 2008. In addition, the *Carbon Tax Act*, which received Royal Assent by the Legislative Assembly of British Columbia on May 29, 2008, introduced a consumption tax on carbon-based fuels which impacts the competitiveness of natural gas versus non-carbon-based energy sources. The legislation did not, however, introduce a carbon tax on imported electricity generated through the combustion of carbon-based fuels. The future impact of the Government of British Columbia's Energy Plan and the recent legislation may have a material impact on the competitiveness of natural gas relative to other energy sources.

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Environmental Risks: The Corporation and its subsidiaries are subject to numerous laws, regulations and guidelines governing the generation, management, storage, transportation, recycling and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment. Environmental damage and associated costs could potentially arise due to a variety of events, including the impact of severe weather and natural disasters on facilities and equipment and equipment failure. Costs arising from environmental protection initiatives, compliance with environmental laws, regulations and guidelines, or damages may become material to the Corporation and its subsidiaries. In addition, the process of obtaining environmental regulatory approvals, including any necessary environmental assessments, can be lengthy, contentious and expensive. During 2008, costs arising from environmental protection, compliance or damages were not material to the Corporation's consolidated results of operations, cash flows or financial position. The Corporation believes that it and its subsidiaries are materially compliant with environmental laws, regulations and guidelines applicable to them in the various jurisdictions in which they operate. As at December 31, 2008, there were no material environmental liabilities recorded in the Corporation's 2008 Consolidated Financial Statements and there were no material unrecorded environmental liabilities known to management. The regulated utilities would seek to recover in customer rates the costs associated with environmental protection, compliance or damages; however, there is no assurance that the regulators will agree with the utilities' requests and, therefore, unrecovered costs, if substantial, could materially affect the results of operations, cash flows and financial position of the utilities.

From time to time, it is possible that the Corporation and its subsidiaries may become subject to government orders, investigations, inquiries or other proceedings relating to environmental matters. The occurrence of any of these events, or any changes in applicable environmental laws, regulations and guidelines or their enforcement or regulatory interpretation, could materially impact the results of operations, cash flows and financial position of the Corporation and its subsidiaries.

The Corporation's gas and electricity businesses are subject to inherent risks, including risk of fires and contamination of air, soil or water from hazardous substances. Risks associated with fire damage relate to the extent of forest and grassland cover, habitation and third-party facilities located on or near the land on which the utilities' facilities are situated. The utilities may become liable for fire suppression costs, regeneration and timber value costs and third-party claims in connection with fires on lands on which its facilities are located if it is found that such facilities were the cause of a fire, and such claims, if successful, could be material. Risks also include the responsibility for remediation of contaminated properties, whether or not such contamination was actually caused by the property owner. The risk of contamination of air, soil and water at the electric utilities primarily relates to the storage and handling of large volumes of fuel, the use and disposal of petroleum-based products, mainly transformer and lubricating oil, in the utilities' day-to-day operating and maintenance activities, and emissions from the combustion of fuel required in the generation of electricity. The risk of contamination of air, soil or water at the natural gas utilities primarily relates to natural gas and propane leaks and other accidents involving these substances. The management of greenhouse gas emissions is the main environmental concern of the Corporation's regulated gas utilities, primarily due to recent changes to the Government of British Columbia's Energy Plan and related legislation as discussed above. Any changes in environmental laws, regulations or guidelines governing contamination could lead to significant increases in costs to the Corporation and its subsidiaries.

The key environmental hazards related to hydroelectric generation operations include the creation of artificial water flows that may disrupt natural habitats and the storage of large volumes of water for the purpose of electricity generation.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electric and magnetic fields from power lines, household appliances and other electricity sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health hazard, litigation could result and the electric utilities could be required to pay damages and take mitigation measures on its facilities. The costs of litigation, damages awarded and mitigation measures, if not approved by regulators for recovery in customer rates, could materially impact the results of operations, cash flows and financial condition of the electric utilities.

While the Corporation and its subsidiaries maintain insurance, there can be no assurance that all possible types of liabilities that may arise related to environmental matters will be covered by the insurance. For further information on insurance, refer to the "Business Risk Management – Insurance Coverage Risk" section of this MD&A.

The Corporation's utilities address environmental matters in their operations through the use of Environmental Management Systems ("EMS"). As part of their respective EMS, the utilities are continuously establishing and implementing programs and procedures to identify potential environmental impacts, mitigate those impacts and monitor environmental performance.

Insurance Coverage Risk: While the Corporation and its subsidiaries maintain insurance, a significant portion of the Corporation's regulated electric utilities' T&D assets are not covered under insurance, as is customary in North America, as the cost of the coverage is not considered economical. Insurance is subject to coverage limits as well as time-sensitive claims discovery and

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reporting provisions and there can be no assurance that the types of liabilities that may be incurred by the Corporation and its subsidiaries will be covered by insurance. The Corporation's regulated utilities would likely apply to their respective regulatory authorities to recover the loss or liability through increased customer rates. However, there can be no assurance that regulatory authorities would approve any such application in whole or in part. Any major damage to the physical assets of the Corporation and its subsidiaries could result in repair costs and customer claims that are substantial in amount and which could have an adverse effect on the Corporation's and subsidiaries' business, results of operations and financial condition. In addition, the occurrence of significant uninsured claims, claims in excess of the insurance coverage limits maintained by the Corporation and its subsidiaries, or claims that fall within a significant self-insured retention could have a material adverse effect on the Corporation's and subsidiaries' business, results of operations and financial position.

It is anticipated that such insurance coverage will be maintained. However, there can be no assurance that the Corporation and its subsidiaries will be able to obtain or maintain adequate insurance in the future at rates considered reasonable or that insurance will continue to be available on terms as favourable as the existing arrangements or that the insurance companies will meet their obligations to pay claims.

Licences and Permits: The acquisition, ownership and operation of gas and electric utilities and assets require numerous licences, permits, approvals and certificates from various levels of government and government agencies. The Corporation's regulated utilities and non-regulated generation operations may not be able to obtain or maintain all required regulatory approvals. If there is a delay in obtaining any required regulatory approval, or if there is a failure to obtain or maintain any required approval or to comply with any applicable law, regulation or condition of an approval, the operation of the assets and the sale of gas and electricity could be prevented or become subject to additional costs, any of which could materially affect the subsidiaries.

Loss of Service Area: FortisAlberta serves customers residing within various municipalities throughout its service areas. From time to time, municipal governments in Alberta give consideration to creating their own electric distribution utilities by purchasing the assets of FortisAlberta that are located within their municipal boundaries. Upon the termination of its franchise agreement, a municipality has the right, subject to AUC approval, to purchase FortisAlberta's assets within its municipal boundaries pursuant to the *Municipal Government Act* (Alberta). Under the *Hydro and Electric Energy Act* (Alberta), if a municipality that owns an electric utility expands its boundaries, it can acquire FortisAlberta's assets in the annexed area. In such circumstances, the *Hydro and Electric Energy Act* (Alberta) provides for compensation, including payment for FortisAlberta's assets on the basis of replacement cost less depreciation. Given the historical growth of Alberta and its municipalities, FortisAlberta may be affected by transactions of this type.

The consequence to FortisAlberta of a municipality purchasing its distribution assets would be an erosion of the Company's rate base, which would reduce the capital upon which FortisAlberta could earn a regulated return. No transactions are currently in progress with FortisAlberta pursuant to the *Municipal Government Act* (Alberta). However, upon expiration of franchise agreements, there is a risk that municipalities will opt to purchase the distribution assets existing within their boundaries, the loss of which could materially affect the financial condition and results of operations of FortisAlberta.

Market Energy Sales Prices: The Corporation's primary exposure to changes in market energy sales prices at its electricity operations has related to its non-regulated energy sales in Ontario, where energy is sold to the Independent Electricity System Operator at market prices. Non-regulated energy sales in Ontario largely relate to a power-for-water exchange agreement, known as the Niagara Exchange Agreement, associated with the Rankine hydroelectric generating station. In accordance with this agreement, FortisOntario's water entitlement on the Niagara River will expire on April 30, 2009 and, as a result, the Corporation's exposure to market price fluctuations in Ontario will be substantially reduced and earnings related to the Niagara Exchange Agreement will cease after that date. During 2008, earnings' contribution associated with the Niagara Exchange Agreement was approximately \$16 million. The Corporation is also exposed to changes in energy prices related to energy sales from its non-regulated generation assets in Upper New York State. All energy produced by these assets is sold to the National Grid at market prices. Energy from the Corporation's non-regulated generation assets in Belize, central Newfoundland and British Columbia is sold under medium- and long-term fixed-price contracts.

Transition to International Financial Reporting Standards: Effective January 1, 2011, Canadian publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). IFRS will require increased financial statement disclosure compared to Canadian GAAP and accounting policy differences between Canadian GAAP and IFRS will need to be addressed by Fortis. The Corporation is currently assessing the impact a conversion to IFRS would have on its future financial reporting. In the event regulated assets and liabilities are not permissible under IFRS, this could result in increased volatility in the Corporation's consolidated earnings and balance sheet from that reported under Canadian GAAP. Information on the Corporation's IFRS conversion project is provided in the "Future Accounting Changes" section of this MD&A.

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Changes in Tax Legislation: The Government of Canada has enacted legislative changes that will challenge the continuation of the tax-deferred status of offshore earnings derived from foreign affiliates. The legislative changes will require that the governments of these tax-free jurisdictions enter into tax treaties or other comprehensive tax information-exchange agreements ("TIEAs") with Canada before 2015. If the jurisdictions are unable to establish these treaties or agreements, the earnings of Canadian subsidiaries operating in these jurisdictions will be taxed on an accrual basis after 2014 as if they were in Canada. Conversely, if treaties or agreements can be reached, the earnings from these jurisdictions will be able to be repatriated to Canada tax free. In the event that the offshore earnings become taxable, earnings' contribution from the Corporation's Caribbean Regulated Electric utilities and BECOL will decrease.

On December 10, 2008, the Advisory Panel on Canada's System of International Taxation (the "Advisory Panel") provided its recommendations to the Minister of Finance of the Government of Canada in its final report, "Enhancing Canada's International Tax Advantage". The Advisory Panel was formed by the Government of Canada in November 2007 to provide recommendations to improve Canada's international tax policy respecting foreign investment by Canadian businesses and investment in Canada by foreign businesses. The Advisory Panel's recommendations seek to improve Canada's tax system regarding outbound and inbound business investment, non-resident withholding taxes, and administration, compliance and legislative processes. Specifically, the Advisory Panel recommended that the Government of Canada pursue TIEAs on a government-to-government basis without resorting to accrual taxation for foreign active business income if a TIEA is not obtained. The Advisory Panel also recommended that the Government of Canada broaden the existing exemption system to cover all foreign active business income earned by foreign affiliates.

On January 27, 2009, the Government of Canada introduced its 2009 Budget. In the budget documents, the Government of Canada indicated that it is studying the Advisory Panel's report and will provide a response in due course on which consultations will be held. The Government of Canada also indicated that it will consider the Advisory Panel's recommendations relating to foreign affiliates before proceeding with the remaining foreign affiliate measures announced in February 2004, as modified to take into account consultations and deliberations since their release.

Any future changes in other tax legislation could also materially affect the Corporation's consolidated earnings.

First Nations' Lands: The Terasen Gas companies and FortisBC provide service to customers on First Nations' lands and maintain gas and electric distribution facilities on lands that are subject to land claims by various First Nations. A treaty negotiation process involving various First Nations and the Government of British Columbia is underway, but the basis upon which settlements might be reached in the service areas of the Terasen Gas companies and FortisBC is not clear. Furthermore, not all First Nations are participating in the process. To date, the policy of the Government of British Columbia has been to endeavour to structure settlements without prejudicing existing rights held by third parties, such as the Terasen Gas companies and FortisBC. However, there can be no certainty that the settlement process will not materially affect the business of the Terasen Gas companies and FortisBC. In addition, FortisAlberta has distribution assets on First Nations' lands with access permits to these lands held by FortisAlberta's predecessor, TransAlta Utilities Corporation ("TransAlta"). In order for FortisAlberta to acquire these access permits, both the Department of Indian and Northern Affairs Canada and the individual Band councils must grant approval. FortisAlberta may not be able to acquire the access permits from TransAlta and may be unable to negotiate land-usage agreements with property owners or, if negotiated, such agreements may be on terms that are less than favourable to FortisAlberta and, therefore, may have a material effect on the business of FortisAlberta.

Labour Relations: Approximately 60 per cent of the employees of the Corporation's subsidiaries are members of labour unions or associations which have entered into collective bargaining agreements with the subsidiaries. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the businesses carried out by the subsidiaries. The Corporation considers the relationships of its subsidiaries with its labour unions and associations to be satisfactory but there can be no assurance that current relations will continue in future negotiations or that the terms under the present collective bargaining agreements will be renewed. The inability to maintain or renew the collective bargaining agreements on acceptable terms could result in increased labour costs or service interruptions arising from labour disputes that are not provided for in approved rate orders at the regulated utilities and which could have a material effect on the results of operations, cash flow and earnings of the utilities.

The collective agreement between FortisBC and the International Brotherhood of Electrical Workers ("IBEW"), Local 213, expired on January 31, 2009. A new four-year collective agreement was ratified by the union in February 2009.

In September 2008, two collective agreements governing Newfoundland Power's unionized employees represented by IBEW, Local 1620, expired. In February 2009, one of the groups represented by IBEW, Local 1620, ratified a new collective agreement. This new collective agreement will be effective October 1, 2008 and will expire on September 30, 2011. The second collective agreement is subject to a conciliation process which began in March 2009.

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In December 2008, the collective agreement governing Maritime Electric's unionized employees represented by IBEW, Local 1432, expired. Maritime Electric and IBEW are currently negotiating a new collective agreement.

Human Resources: The ability of Fortis to deliver superior operating performance in a cost-effective manner is dependent on the ability of the Corporation's subsidiaries to attract, develop and retain skilled workforces. Like other utilities across Canada and the Caribbean, the Corporation's utilities are faced with demographic challenges relating to trades, technical staff and engineers. The growing size of the Corporation and an increasingly competitive job market present ongoing recruitment challenges. The Corporation's significant consolidated capital expenditure program over the next several years will present challenges in ensuring the Corporation's utilities have the qualified workforce necessary to complete the capital work initiatives.

Changes in Accounting Standards

The nature of, and impact on Fortis of, adopting the new Canadian Institute of Chartered Accountants ("CICA") accounting standards for Inventories, Capital Disclosures, and Disclosure and Presentation of Financial Instruments, effective January 1, 2008, are described in detail in Notes 5, 24, 25 and 26 to the 2008 Consolidated Financial Statements. The most significant impacts of adopting the new standards were: (i) the reclassification of \$26 million of inventories to utility capital assets from inventories on the consolidated balance sheet as at December 31, 2007; (ii) additional disclosures about the Corporation's capital, including quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital; and (iii) additional disclosures of both qualitative and quantitative information that enable users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed. The adoption of the accounting standards did not have a material impact on the Corporation's 2008 Consolidated Financial Statements.

Future Accounting Changes

IFRS: In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an IFRS Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011.

On June 27, 2008, the Canadian Securities Administrators ("CSA") issued Staff Notice 52-321, *Early Adoption of IFRS* which indicated that the CSA would be prepared to grant an exemption to allow Canadian financial statement issuers to adopt IFRS early on a case-by-case basis, provided that they could demonstrate that they met certain conditions. Fortis is not planning to early adopt IFRS.

The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010 and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section – *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued, but is not yet effective and that the entity has not applied, not be applied with respect to the IFRS Omnibus Exposure Draft.

Fortis is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Fortis does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required as well as systems changes that may be necessary to gather and process the required information.

Fortis commenced its IFRS conversion project in 2007 and has established a formal project governance structure which includes the audit committees, senior management and project teams from each of the Corporation's subsidiaries. Overall project governance, management and support are coordinated by Fortis Inc. Regular reporting occurs to the Audit Committee of the Board of Directors of Fortis and of the subsidiaries, where appropriate. An external expert advisor has been engaged to assist in the IFRS conversion project.

The Corporation's IFRS conversion project consists of three phases: Scoping and Diagnostics, Analysis and Development, and Implementation and Review.

Phase One: Scoping and Diagnostics, which involved project planning and staffing and identification of differences between current Canadian GAAP and IFRS, has been completed. The resulting identified areas of accounting difference of highest potential impact to Fortis, based on existing IFRS, are rate-regulated accounting; property, plant and equipment; investment property; provisions and contingent liabilities; employee benefits; impairment of assets; income taxes; business combinations; and initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS*.

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Phase Two: Analysis and Development is nearing completion and involves detailed diagnostics and evaluation of the financial reporting impacts of various options and alternative methodologies provided for under IFRS; identification and design of operational and financial business processes; initial staff and audit committee training; analysis of IFRS 1 optional exemptions and mandatory exceptions to the general requirement for full retrospective application upon transition to IFRS; summarization of 2011 IFRS disclosure requirements; and development of required solutions to address identified issues.

The Corporation has completed a preliminary assessment of the impacts of adopting IFRS; however, a final assessment cannot be completed at this time pending the outcome of the project on rate-regulated activities that was recently added to the IASB's technical agenda.

It is anticipated that the adoption of IFRS will have an impact on information systems requirements. Each of the Corporation's subsidiaries is assessing the need for system upgrades or modifications to ensure an efficient conversion to IFRS. As part of Phase Two, information systems plans are being prepared for implementation in Phase Three. The extent of the impact on each of the subsidiary's information systems is not reasonably determinable at this time.

During 2008, several regulatory authorities with jurisdiction over the Corporation's regulated utilities began their own IFRS projects to determine the nature of any changes that should be made in regulatory accounting requirements in response to IFRS. The Corporation's regulated utilities have worked and will continue to work with their respective regulatory authorities to identify transitional issues and suggest how those issues might be addressed.

Phase Three: Implementation and Review, expected to commence mid-year 2009, will involve the execution of changes to information systems and business processes; completion of formal authorization processes to approve recommended accounting policy changes; and further training programs across the Corporation's finance and other affected areas, as necessary. It will culminate in the collection of financial information necessary to compile IFRS-compliant financial statements and reconciliations; embedding of IFRS in business processes and Audit Committee approval of IFRS-compliant financial statements.

Fortis will continue to review all proposed and continuing projects of the IASB, particularly the project on rate-regulated activities that was recently added to the IASB's technical agenda and proposed amendments to IFRS 1 for entities with operations subject to rate regulation, and will participate in any related processes as appropriate.

Rate-Regulated Operations: Effective January 1, 2009, the AcSB amended: (i) CICA Handbook Section 1100, *Generally Accepted Accounting Principles* removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) Section 3465, *Income Taxes* to require the recognition of future income tax liabilities and assets as well as offsetting regulatory assets and liabilities by entities subject to rate regulation.

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes* will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the cash taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes* as at December 31, 2008, would have been an increase in future income tax assets and future income tax liabilities of \$24 million and \$497 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of \$24 million and \$497 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates and the separate disclosure of future income tax assets and liabilities that are currently not recognized.

Effective January 1, 2009, with the removal of the temporary exemption in Section 1100, the Corporation must now apply Section 1100 to the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. The assets and liabilities arising from rate regulation, as described in Note 4 to the 2008 Consolidated Financial Statements, do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. The Corporation's regulatory assets and liabilities

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qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption in Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets: Effective January 1, 2009, the Corporation will adopt the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of \$234 million, a reduction in utility capital assets of \$232 million and a reduction in deferred charges and other assets of \$2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities: Effective January 1, 2009, the Corporation will adopt the new Emerging Issues Committee ("EIC")-173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, which was issued on January 20, 2009. EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. As at December 31, 2008, only the Corporation's derivative financial instruments were recorded at fair value, the majority of which were out-of-the-money and recorded as a liability. The Corporation is continuing to assess any additional financial reporting impacts of adopting this EIC.

Financial Instruments

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the Corporation's consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by using quoted market prices when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

An increase in credit risk and spreads as a result of the volatility experienced in the financial and capital markets has resulted in lower fair values for the Corporation's consolidated long-term debt and preference shares as at December 31, 2008 compared to December 31, 2007.

The carrying and fair values of the Corporation's consolidated long-term debt and preference shares as at December 31 were as follows.

Financial Instruments⁽¹⁾

As at December 31

	2008		2007	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
(\$ millions)				
Long-term debt, including current portion ⁽¹⁾	5,088	4,927	5,023	5,635
Preference shares, classified as debt ⁽²⁾	320	329	320	346

⁽¹⁾ Carrying value as at December 31, 2008 is net of unamortized deferred financing costs of \$34 million (December 31, 2007 – \$33 million).

⁽²⁾ Preference shares classified as equity do not meet the definition of a financial instrument; however, the estimated fair value of the Corporation's \$347 million of preference shares classified as equity was \$268 million at December 31, 2008 (December 31, 2007 – carrying value \$122 million; fair value \$107 million).

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes.

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The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

Derivative Financial Instruments

As at December 31

Asset (Liability)	2008				2007	
	Term to Maturity (years)	Number of Contracts	Carrying Value (\$ millions)	Estimated Fair Value (\$ millions)	Carrying Value (\$ millions)	Estimated Fair Value (\$ millions)
Interest Rate Swaps	1 to 2	2	–	–	–	–
Foreign Exchange Forward Contract	<3	1	7	7	–	–
Natural Gas Derivatives:						
Swaps and Options	Up to 3	228	(84)	(84)	(79)	(79)
Gas Purchase Contract Premiums	Up to 3	74	(8)	(8)	5	5

The interest rate swaps are held by Fortis Properties and are designated as hedges of the cash flow risk related to floating-rate long-term debt and mature in July 2009 and October 2010. The effective portion of changes in the fair value of the interest rate swaps at Fortis Properties is recorded in other comprehensive income. During 2008, the interest rate swaps of the Terasen Gas companies matured.

The foreign exchange forward contract is held by TGVF and is designated as a hedge of the cash flow risk related to approximately US\$55 million required to be paid under a contract for the construction of an LNG storage facility.

The natural gas derivatives are used to fix the effective purchase price of natural gas as the majority of the natural gas supply contracts have floating, rather than fixed, prices. At the Terasen Gas companies, changes in the fair value of interest rate swaps, the foreign exchange forward contract and natural gas derivatives are deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates. The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – accounts payable and accounts receivable).

The interest rate swaps are valued at the present value of future cash flows based on published forward future interest rate curves. The foreign exchange forward contract is valued using the present value of future cash flows based on published forward future foreign exchange market rate curves. The fair values of the natural gas derivatives reflect the estimated amounts, based on published forward curves, the Terasen Gas companies would have to receive or pay if forced to settle all outstanding contracts at the balance sheet date.

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

Critical Accounting Estimates

The preparation of the Corporation's consolidated financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances.

Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period they become known. The Corporation's critical accounting estimates are discussed below.

Regulation: Generally, the accounting policies of the Corporation's regulated utilities are subject to examination and approval by the respective regulatory authorities. These accounting policies may differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenues and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP for entities not subject to rate regulation. Regulatory assets and regulatory liabilities arise as a result of the rate-setting process at the regulated utilities and have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since the regulatory environments in which the Corporation's

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regulated utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the regulatory authorities for deferral as regulatory assets and regulatory liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates are reported in earnings in the period in which they become known. As at December 31, 2008, Fortis recorded \$360 million in current and long-term regulatory assets (December 31, 2007 – \$312 million) and \$446 million in current and long-term regulatory liabilities (December 31, 2007 – \$392 million). The increase in regulatory assets year over year was primarily due to amounts deferred in FortisAlberta's AESO charges deferral account in 2008 and the deferral of an increase in the cost of fuel and power at Maritime Electric and Caribbean Utilities. The increase in regulatory liabilities year over year was largely associated with BCUC-approved rate stabilization accounts at the Terasen Gas companies. The nature of the Corporation's regulatory assets and liabilities is described in Note 4 to the 2008 Consolidated Financial Statements.

Capital Asset Amortization: Amortization, by its nature, is an estimate based primarily on the useful life of assets. Estimated useful lives are based on current facts and historical information and take into consideration the anticipated physical life of the assets. As at December 31, 2008, the Corporation's consolidated utility capital assets and income producing properties were approximately \$7.9 billion, or approximately 71 per cent of total consolidated assets, compared to consolidated utility capital assets and income producing properties of \$7.3 billion, or approximately 71 per cent of total consolidated assets, as at December 31, 2007. The increase in capital assets was primarily associated with capital expenditures, which totalled \$904 million in 2008. Amortization expense for 2008 was \$348 million compared to \$273 million for 2007. Changes in amortization rates may have a significant impact on the Corporation's consolidated amortization expense.

As part of the customer rate-setting process at the Corporation's regulated utilities, appropriate amortization rates are approved by the respective regulatory authorities. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds, over the life of the assets. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the provision when incurred. The accrual of the estimated costs is included with amortization expense and the provision balance is recorded as a long-term regulatory liability. The estimate of the future asset removal and site restoration costs, net of salvage proceeds, is based on historical experience and future expected cost trends. The balance of this regulatory liability at December 31, 2008 was \$337 million (December 31, 2007 – \$319 million). The amount of future asset removal and site restoration costs provided for and reported in amortization expense during 2008 was \$35 million (2007 – \$33 million).

The amortization periods used and the associated rates are reviewed on an ongoing basis to ensure they continue to be appropriate. From time to time, third-party depreciation studies are performed at the regulated utilities. Based on the results of these depreciation studies, the impact of any over or under amortization, as a result of actual experience differing from that expected and provided for in previous amortization rates, is generally reflected in future amortization rates and amortization expense, when the differences are refunded or collected in customer rates as approved by the regulator. Changes in regulator-approved amortization rates at FortisAlberta and Newfoundland Power during 2008 did not have a material impact on consolidated amortization expense.

Capitalized Overhead: As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity and, commencing in May 2008, Caribbean Utilities capitalize overhead costs which are not directly attributable to specific capital assets but which relate to the overall capital expenditure program. These general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. The methodology for calculating and allocating these general expenses to utility capital assets is established by the respective regulators. In 2008, GEC totalled \$57 million (2007 – \$42 million). Any change in the methodology of calculating and allocating general overhead costs to utility capital assets could have a material impact on the amount recorded as operating expenses versus utility capital assets.

Goodwill Impairment Assessments: Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost, less any previous amortization and write-down for impairment. The Corporation is required to perform an annual impairment test and at such time any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. In July of each year, the Corporation reviews for impairment of goodwill and updates its review as at year end. To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of

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the goodwill over the implied fair value of the goodwill is the impairment amount. Fair market value is determined using net present value financial models and management's assumption of future profitability of the reporting units. There was no impairment provision required on \$1.6 billion of goodwill recorded on the Corporation's balance sheet as at December 31, 2008. For a discussion of the nature of the change in goodwill during 2008, refer to the "Consolidated Financial Position" section of this MD&A.

Employee Future Benefits: The Corporation's and subsidiaries' defined benefit pension plans and other post-employment benefit ("OPEB") plans are subject to judgments utilized in the actuarial determination of the expense and related obligation. The main assumptions utilized by management in determining pension expense and obligations are the discount rate for the accrued pension benefit obligation and the expected long-term rate of return on plan assets.

The assumed long-term rates of return on the defined benefit pension plan assets, for the purpose of estimating pension expense for 2009, range from 6.75 per cent to 7.25 per cent for the larger defined benefit pension plans. These rates compare to assumed long-term rates of return used in 2008 that ranged from 6.50 per cent to 7.50 per cent. The defined benefit pension plan assets experienced total negative returns during 2008 of approximately \$92 million compared to expected positive returns of \$49 million. The assumed expected long-term rates of return on pension plan assets fall within the range of expected returns as provided by the actuaries' internal models.

The assumed discount rates used to measure the accrued pension benefit obligations on the applicable measurement dates in 2008 and to determine pension expense for 2009 ranged from 6.00 per cent to 7.50 per cent for the larger defined benefit plans. These rates compare to assumed discount rates used to measure the accrued pension benefit obligations in 2007 and determine pension expense for 2008 that ranged from 5.25 per cent to 5.60 per cent. The discount rates increased as a result of the impact of increased credit risk spreads on investment-grade corporate bonds due to volatility in the capital markets. Discount rates reflect market interest rates on high-quality bonds with cash flows that match the timing and amount of expected pension payments. The methodology in determining the discount rates was consistent with that used to determine the discount rates in the previous year.

As the measurement date for FortisAlberta, FortisBC and FortisOntario's defined benefit pension plans is September 30, 2008, the further impact on credit risk spreads of capital market volatility that continued through the remainder of 2008 was not reflected in the discount rates assumed by these utilities as at September 30, 2008, nor was the further erosion of capital market value reflected in the fair value of the pension plan assets measured as at September 30, 2008.

Fortis expects no material increase in its consolidated pension expense for 2009 related to its defined benefit pension plans. The amortization of 2008 losses associated with the pension plan assets is expected to be largely offset by the impact of higher assumed discount rates. The impact of the decline in pension plan assets in 2008, as it relates to 2009 pension expense, is being mitigated by the use of the market-value related method for valuing pension assets at the Terasen Gas companies and Newfoundland Power.

Consolidated defined benefit pension expense and pension funding obligations for 2009 may be affected, however, by the outcome of December 31, 2008 actuarial valuations which, for Newfoundland Power, the Corporation and for one of the defined benefit pension plans at Terasen, are expected to be completed in 2009.

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2008 net defined benefit pension expense, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation. The sensitivity analysis applies to the Corporation's Regulated Gas Utilities and Regulated Electric Utilities.

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Sensitivity Analysis of Changes in Rate of Return on Plan Assets and Discount Rate

Year Ended December 31, 2008

Increase (decrease)	Net benefit expense		Accrued benefit asset		Accrued benefit liability		Benefit obligation	
	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities	Regulated Gas Utilities	Regulated Electric Utilities
(\$ millions)								
Impact of increasing the rate of return assumption by 100 basis points	(3)	(4)	3	4	–	–	–	–
Impact of decreasing the rate of return assumption by 100 basis points	3	4	(3)	(4)	–	–	–	–
Impact of increasing the discount rate assumption by 100 basis points	–	(3)	(1)	3	(1)	–	(19)	(38)
Impact of decreasing the discount rate assumption by 100 basis points	4	6	(3)	(5)	1	–	21	46

Other assumptions applied in measuring defined benefit pension expense and/or the accrued pension benefit obligation were the average rate of compensation increase, average remaining service life of the active employee group, and employee and retiree mortality rates.

The OPEB plans of the Corporation and its subsidiaries are also subject to judgments utilized in the actuarial determination of the expense and related obligation. The assumptions described above, except for the assumptions of the expected long-term rate of return on pension plan assets and average rate of compensation increase, along with health care cost trends, were also utilized by management in determining OPEB plan expense and obligations.

As approved by the respective regulators, FortisAlberta and Newfoundland Power record the cost of defined benefit pension and/or OPEB plan benefits on a cash basis, whereby differences between the cash payments made during the year and the expense incurred during the year are deferred as a regulatory asset or regulatory liability. Therefore, changes in assumptions cause changes in regulatory assets and liabilities for these companies and do not affect earnings. As disclosed in the “Business Risk Management – Defined Benefit Pension Plan Performance and Funding Requirements” section of this MD&A, the Terasen Gas companies and FortisBC have regulator-approved mechanisms to defer variations in pension expense from forecast pension expense, used to set customer rates, as a regulatory asset or regulatory liability.

As at December 31, 2008, the Corporation had a consolidated accrued benefit asset of \$133 million (December 31, 2007 – \$120 million) and a consolidated accrued benefit liability of \$168 million (December 31, 2007 – \$150 million). During 2008, the Corporation recorded consolidated net benefit expense of \$27 million (2007 – \$26 million).

Asset-Retirement Obligations: The measurement of fair value of asset-retirement obligations (“AROs”) requires making reasonable estimates concerning the method of settlement and settlement dates associated with the legally obligated asset-retirement costs. While the Corporation has AROs associated with hydroelectric generating facilities, interconnection facilities, wholesale energy supply agreements, removal of certain distribution system assets from rights of way at the end of the life of the systems and the remediation of certain land, there were no amounts recorded as at December 31, 2008 and 2007. The nature, amount and timing of costs associated with land and environmental remediation and/or removal of assets cannot be reasonably estimated at this time as the hydroelectric generation and distribution and transmission assets are reasonably expected to operate in perpetuity due to the nature of their operation; applicable licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the related assets and ensure the continued provision of service to customers; a land-lease agreement is expected to be renewed indefinitely; and the exact nature and amount of land remediation is indeterminable. In the event that environmental issues are known and identified, assets are decommissioned, or the applicable licences, permits, agreements or leases are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

Revenue Recognition: All of the Corporation’s regulated utilities, except for Belize Electricity, recognize revenue on an accrual basis. As required by the PUC, Belize Electricity recognizes electricity revenue on a billed basis. Recording revenue on an accrual basis requires use of estimates and assumptions. Customer bills are issued throughout the month based on meter readings that

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establish gas and electricity consumption by customers since the last meter reading. The unbilled revenue accrual for the period is based on estimated gas and electricity sales to customers for the period since the last meter reading at the rates approved by the respective regulatory authorities. The development of the gas and electricity sales estimates generally requires analysis of consumption on a historical basis in relation to key inputs such as the current price of gas and electricity, population growth, economic activity, weather conditions and system losses. The estimation process for accrued unbilled gas and electricity consumption will result in adjustments of gas and electricity revenue in the periods they become known when actual results differ from the estimates. As at December 31, 2008, the amount of accrued unbilled revenue recorded in accounts receivable was approximately \$365 million (December 31, 2007 – \$309 million) on annual consolidated revenue of approximately \$3.9 billion (2007 – \$2.7 billion).

Contingencies: The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately \$37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to \$7 million, including interest, which has been paid in full to avoid accruing further interest and recorded as a long-term regulatory deferral asset. The matter is currently under appeal to the Supreme Court of British Columbia.

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from CRA for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the 2008 Consolidated Financial Statements. Terasen has begun the appeal process associated with the assessments.

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGVI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the 2008 Consolidated Financial Statements.

FortisBC

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the 2008 Consolidated Financial Statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately \$6 million on January 2, 2001 associated with a settlement with NB Power regarding its \$450 million write-down of the Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation which confirmed the April 2006 reassessments. The Company will file an Appeal to the Tax Court of Canada.

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately \$13 million in taxes and accrued interest. As at December 31, 2008, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately \$6 million.

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FortisUS Energy

During 2008, a statutory discontinuance and final release of FortisUS Energy was issued in relation to legal proceedings initiated by the Village of Philadelphia (the "Village"), New York. The Village had claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately \$9 million (US\$7 million). There was no impact on the 2008 Consolidated Financial Statements as a result of the settlement of these legal proceedings.

Exploits Partnership

On December 16, 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of the Newfoundland assets of Abitibi-Consolidated. Prior to that date, Abitibi-Consolidated announced the closure of its Grand Falls-Windsor, Newfoundland newsprint mill, effective March 31, 2009. The hydroelectric generating facility assets of the Exploits Partnership were included as part of the expropriation legislation. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The financial statements of the Exploits Partnership are consolidated in the financial statements of Fortis. The Exploits Partnership has a \$61 million term loan, which is non-recourse to Fortis, with several lenders which is secured by the assets of the Exploits Partnership.

Discussions are ongoing with Exploits Partnership's lenders with respect to the above matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated. Pending resolution of these matters, the deferred financing costs of \$2 million and utility capital assets of \$61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the \$61 million term loan has been reclassified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

Selected Annual Financial Information

The following table sets forth the annual financial information for the years ended December 31, 2008, 2007 and 2006. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities.

Selected Annual Financial Information

Years Ended December 31

(\$ millions, except per share amounts)

	2008	2007 ⁽¹⁾	2006
Revenue and equity income	3,903	2,718	1,472
Net earnings	259	199	149
Net earnings applicable to common shares	245	193	147
Total assets	11,178	10,273	5,441
Long-term debt and capital lease obligations (net of current portion)	4,884	4,623	2,558
Preference shares ⁽²⁾⁽³⁾	667	442	442
Common shareholders' equity	3,046	2,601	1,276
Basic earnings per common share	1.56	1.40	1.42
Diluted earnings per common share	1.52	1.32	1.37
Dividends declared per common share	1.01	0.88	0.70
Dividends declared per First Preference Share, Series C	1.3625	1.3625	1.3625
Dividends declared per First Preference Share, Series E	1.2250	1.2250	1.2250
Dividends declared per First Preference Share, Series F ⁽⁴⁾	1.2250	1.2250	0.5211
Dividends declared per First Preference Share, Series G ⁽³⁾	1.0184	—	—

⁽¹⁾ Financial results for 2007 were significantly impacted by the acquisition of Terasen on May 17, 2007.

⁽²⁾ Includes preference shares classified as equity and long-term debt

⁽³⁾ A total of 9.2 million First Preference Shares, Series G were issued on May 23, 2008 and June 4, 2008 at \$25.00 per share for net after-tax proceeds of \$225 million and are entitled to receive cumulative dividends in the amount of \$1.3125 per share per annum.

⁽⁴⁾ 5 million First Preference Shares, Series F were issued on September 28, 2006 at \$25.00 per share for net after-tax proceeds of \$122 million and are entitled to receive cumulative dividends in the amount of \$1.2250 per share per annum.

2008/2007 – Revenue increased 43.6 per cent over 2007. The increase was driven by contributions from the Terasen Gas companies for a full year in 2008 compared to a partial year in 2007. Net earnings applicable to common shares grew 26.9 per cent over 2007. The increase in earnings was primarily due to earnings' contributions from the Terasen Gas companies for a full year in 2008

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compared to a partial year in 2007, rate base growth and higher allowed ROEs at the Corporation's Canadian Regulated Utilities, and increased non-regulated hydroelectric production due to higher rainfall. The increase was tempered by a one-time \$13 million loss related to a June 2008 regulatory rate decision at Belize Electricity and lower corporate tax recoveries at FortisAlberta. The growth in total assets and increase in long-term debt in 2008 was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta, FortisBC and the Terasen Gas companies, combined with the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. The Corporation issued \$230 million preference shares in 2008, the net proceeds of which were primarily used to repay borrowings under the Corporation's committed credit facility, to fund equity requirements of FortisAlberta and the Corporation's regulated electric utilities in the Caribbean, and for general corporate purposes. The Corporation also issued \$300 million common shares in 2008, the net proceeds of which were used to repay short-term debt primarily incurred to retire \$200 million of maturing debt at Terasen, and for general corporate purposes. Basic earnings per common share increased 11.4 per cent from 2007, primarily due to growth in earnings.

2007/2006 – Revenue, including equity income, increased 84.6 per cent over 2006. The increase was driven by contributions from the Terasen Gas companies, from the date of acquisition, and the impact of consolidating the Corporation's approximate 54 per cent controlling ownership in Caribbean Utilities during 2007 compared to recording the Corporation's 37 per cent interest in Caribbean Utilities during 2006 on an equity basis. Net earnings applicable to common shares grew 31.3 per cent over 2006, attributable to the acquisition of Terasen in May 2007, the first full year of ownership of Fortis Turks and Caicos, significant investment in electrical infrastructure at FortisAlberta and FortisBC, stronger performance at Fortis Properties and lower effective corporate taxes. The growth in total assets and increase in long-term debt in 2007 was driven by assets acquired and debt assumed upon the acquisition of Terasen in May 2007. The remaining increase in assets and long-term debt was primarily due to the Corporation's continued investment in energy systems, driven by the capital expenditure programs at FortisAlberta and FortisBC and the acquisition of the Delta Regina, partially offset by the impact of foreign exchange associated with translation of foreign currency-denominated assets and liabilities. Common shareholders' equity more than doubled during 2007, driven by the issuance of approximately \$1.15 billion in common equity required to fund a significant portion of the net cash purchase price of Terasen. Basic earnings per common share decreased 1.4 per cent from 2006. Basic earnings per common share in 2007 were diluted by the common shares issued to fund the acquisition of Terasen and seasonality of earnings at the Terasen Gas companies.

Fourth Quarter Results

The following tables set forth unaudited financial information for the quarters ended December 31, 2008 and 2007. The financial information has been prepared in Canadian dollars and in accordance with Canadian GAAP and as required by utility regulators. A discussion of the financial results for the fourth quarter of 2008 is also contained in the Corporation's fourth quarter 2008 media release, dated and filed on SEDAR at www.sedar.com on February 5, 2009, which is incorporated by reference in this MD&A.

Summary of Volumes, Sales and Revenue

Fourth Quarters Ended December 31
(Unaudited)

	Gas Volumes (TJ) Energy and Electricity Sales (GWh)			Revenue (\$ millions)		
	2008	2007	Variance	2008	2007	Variance
Regulated Gas Utilities – Canadian (TJ)						
Terasen Gas Companies	66,816	69,108	(2,292)	606	548	58
Regulated Electric Utilities – Canadian (GWh)						
FortisAlberta	4,068	4,002	66	78	68	10
FortisBC	842	839	3	66	61	5
Newfoundland Power	1,412	1,384	28	139	132	7
Other Canadian	543	554	(11)	65	66	(1)
	6,865	6,779	86	348	327	21
Regulated Electric Utilities – Caribbean (GWh)	361	272	89	159	76	83
Non-Regulated – Fortis Generation (GWh)	312	303	9	20	19	1
Non-Regulated – Fortis Properties				52	50	2
Corporate and Other				7	6	1
Inter-Segment Eliminations				(10)	(8)	(2)
Total	1,182	1,018	164			

Management Discussion and Analysis

Gas Volumes: Gas volumes at the Terasen Gas companies decreased quarter over quarter, primarily due to lower transportation volumes to customers sourcing their own gas supplies, partially offset by higher sales volumes to residential customers as a result of increased consumption due to cooler weather compared to the same period for the previous year.

Energy and Electricity Sales: Increased energy and electricity sales at the Corporation's regulated electric utilities quarter over quarter were driven by: (i) two additional months of contribution from Caribbean Utilities related to a change in the utility's fiscal year end; (ii) an increase at FortisAlberta mainly due to customer growth; and (iii) an increase at Newfoundland Power primarily due to the combined impact of customer growth and higher average consumption. The increases were partially offset by decreased sales at Other Canadian Electric Utilities, driven by the impact of the shut down of operations of certain industrial customers in Ontario and lower average consumption in Ontario.

The increase in energy sales at Non-Regulated – Fortis Generation was mainly due to higher production in central Newfoundland and Upper New York State. Higher production was mainly the result of higher rainfall.

Revenue: Revenue for the fourth quarter of 2008 was \$164 million higher than the same quarter in 2007. The increase was driven by the Terasen Gas companies and the Corporation's Regulated Electric Utilities. Revenue at the Terasen Gas companies increased quarter over quarter mainly due to higher commodity cost of gas charged to customers, increased residential consumption and an increase in customer gas distribution rates effective January 1, 2008, reflecting a higher allowed ROE for 2008. Increased revenue at Regulated Electric Utilities – Canadian quarter over quarter was mainly due to customer rate increases, which included the impact of higher allowed ROEs for 2008 and customer growth. Revenue at Regulated Electric Utilities – Caribbean increased quarter over quarter primarily due to two additional months of revenue contribution from Caribbean Utilities, an approximate \$30 million favourable impact of foreign exchange associated with the translation of foreign currency-denominated revenue, due to the weakening of the Canadian dollar against the US dollar quarter over quarter, and the flow through to customers of higher energy supply costs.

Summary of Net Earnings Applicable to Common Shares

Fourth Quarters Ended December 31 (Unaudited)

(\$ millions)

	2008	2007	Variance
Regulated Gas Utilities – Canadian			
Terasen Gas Companies	47	52	(5)
Regulated Electric Utilities – Canadian			
FortisAlberta	11	6	5
FortisBC	7	7	–
Newfoundland Power	8	9	(1)
Other Canadian	3	3	–
	29	25	4
Regulated Electric Utilities – Caribbean	8	9	(1)
Non-Regulated – Fortis Generation	8	7	1
Non-Regulated – Fortis Properties	4	8	(4)
Corporate and Other	(20)	(22)	2
Net Earnings Applicable to Common Shares	76	79	(3)

Earnings: Earnings for the fourth quarter of 2008 were \$76 million or \$3 million lower than \$79 million for the same quarter in 2007. Fourth quarter results for 2007 were favourably impacted by one-time items totalling approximately \$13 million related to: (i) the sale of surplus land at TGI; (ii) the reduction of future income tax liability balances at Fortis Properties related to lower enacted corporate income tax rates; and (iii) an interconnection agreement-related refund at FortisOntario. Excluding these one-time items, earnings were \$10 million higher quarter over quarter. The increase was driven by stronger performance and lower corporate taxes at FortisAlberta, lower corporate expenses and \$1 million of additional earnings from Caribbean Utilities related to a change in the utility's fiscal year end. The increase was partially offset by the impact of: (i) a lower allowed ROA at Belize Electricity, effective July 1, 2008; (ii) an approximate \$1 million loss of revenue at Fortis Turks and Caicos related to Hurricane Ike; and (iii) an approximate \$2 million reduction in fourth quarter 2008 earnings at Newfoundland Power associated with a shift in the quarterly distribution of the utility's annual purchased power expense. Newfoundland Power's annual earnings were not affected by the shift in the quarterly distribution of annual purchased power expense.

Management Discussion and Analysis

Summary of Cash Flows

Fourth Quarters Ended December 31 (Unaudited)

(\$ millions)	2008	2007	Variance
Cash, Beginning of Period	68	51	17
Cash Provided By (Used In)			
Operating Activities	214	152	62
Investing Activities	(277)	(234)	(43)
Financing Activities	58	89	(31)
Foreign Currency Impact on Cash Balances	3	—	3
Cash, End of Period	66	58	8

Cash flow provided from operating activities, after working capital adjustments, increased \$62 million quarter over quarter. The increase was mainly due to favourable working capital changes at the Terasen Gas companies related to the impact of cooler weather and higher commodity natural gas costs charged to customers during the fourth quarter of 2008 compared to the fourth quarter of 2007. The increase was partially offset by lower cash from operating activities at FortisAlberta. However, during the fourth quarter of 2007, FortisAlberta received cash from the sale of amounts in its 2007 AESO charges deferral account.

Cash used in investing activities increased \$43 million quarter over quarter, reflecting higher utility capital expenditures and the acquisition of the Fairmount Newfoundland hotel in November 2008.

Cash provided from financing activities was \$31 million lower quarter over quarter. Increased cash associated with the \$300 million common share issue in the fourth quarter of 2008 was more than offset by the impact of a net decrease in debt during the fourth quarter of 2008 compared to a net increase in debt during the same quarter for the previous year.

Quarterly Results

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2007 through December 31, 2008. The quarterly information has been prepared in Canadian dollars and obtained from the Corporation's interim unaudited consolidated financial statements which, in the opinion of management, have been prepared in accordance with Canadian GAAP and as required by utility regulators. The timing of the recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian GAAP for non-regulated entities. These financial results are not necessarily indicative of results for any future period and should not be relied upon to predict future performance.

Summary of Quarterly Results

(Unaudited)

Quarter Ended	Revenue (\$ millions)	Net Earnings Applicable to Common Shares (\$ millions)	Earnings per Common Share	
			Basic (\$)	Diluted (\$)
December 31, 2008	1,182	76	0.48	0.46
September 30, 2008	727	49	0.31	0.31
June 30, 2008	848	29	0.19	0.18
March 31, 2008	1,146	91	0.58	0.55
December 31, 2007	1,018	79	0.51	0.49
September 30, 2007	651	31	0.20	0.20
June 30, 2007	566	41	0.31	0.27
March 31, 2007	483	42	0.38	0.35

A summary of the past eight quarters reflects the Corporation's continued organic growth, growth from acquisitions, as well as the seasonality associated with its businesses. Interim results will fluctuate due to the seasonal nature of gas and electricity demand and water flows, as well as the timing and recognition of regulatory decisions. Given the diversified group of companies, seasonality may vary. Financial results for the fourth quarter of 2008 include two additional months of contribution from Caribbean Utilities resulting from a change in the utility's fiscal year end. Financial results from May 17, 2007 were impacted by the acquisition of Terasen.

Management Discussion and Analysis

Virtually all of the annual earnings of the Terasen Gas companies are generated in the first and fourth quarters. Financial results for the second quarter of 2008 reflected the \$13 million unfavourable impact to Fortis of a charge recorded at Belize Electricity as a result of the June 2008 regulatory rate decision. Due to a shift in the quarterly distribution of annual purchased power expense at Newfoundland Power, the Company's earnings in 2008 were lower in the first and fourth quarters and higher in the second and third quarters compared to the same periods in 2007. Newfoundland Power's annual earnings were not affected by the shift in the quarterly distribution of annual purchased power expense. Financial results from August 1, 2007 were impacted by the acquisition of the Delta Regina in Saskatchewan.

December 2008/December 2007 – Net earnings applicable to common shares were \$76 million, or \$0.48 per common share, for the fourth quarter of 2008, compared to earnings of \$79 million, or \$0.51 per common share, for the fourth quarter of 2007. A discussion on the variances between the financial results for the fourth quarter of 2008 and the fourth quarter of 2007 is provided in the "Fourth Quarter Results" section of this MD&A.

September 2008/September 2007 – Net earnings applicable to common shares were \$49 million, or \$0.31 per common share, for the third quarter of 2008 compared to earnings of \$31 million, or \$0.20 per common share, for the third quarter of 2007. Third quarter 2008 results included a tax reduction of approximately \$7.5 million associated with the settlement of historical corporate tax matters at Terasen. Excluding the tax reduction at Terasen, earnings for the third quarter of 2008 were \$41.5 million or \$0.26 per common share. Excluding the above one-time item, growth in earnings quarter over quarter was mainly due to higher earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense, higher non-regulated hydroelectric production, increased earnings at FortisBC primarily due to lower energy supply costs and higher earnings at FortisAlberta mainly due to higher corporate tax recoveries. The increase was partially offset by lower earnings at Caribbean Regulated Utilities driven by a 3.25 per cent reduction in basic electricity rates at Caribbean Utilities, a lower allowed ROA at Belize Electricity and a loss of revenue at Fortis Turks and Caicos due to the impact of Hurricane Ike.

June 2008/June 2007 – Net earnings applicable to common shares were \$29 million, or \$0.19 per common share, for the second quarter of 2008 compared to earnings of \$41 million, or \$0.31 per common share, for the second quarter of 2007. Second quarter 2008 results included a \$13 million, or \$0.08 per common share, charge representing the Corporation's approximate 70 per cent share of disallowed previously incurred fuel and purchased power costs at Belize Electricity as well as a \$2 million one-time charge at FortisOntario associated with repayment of interconnection-agreement related amounts received in the fourth quarter of 2007. Excluding the above one-time items, earnings for the second quarter of 2008 were \$44 million compared to \$41 million for the second quarter of 2007. Earnings were favourably impacted by a full quarter of earnings' contribution from the Terasen Gas companies, higher earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense, increased non-regulated hydroelectric production and improved performance at Fortis Properties. Partially offsetting those items were lower earnings at FortisAlberta associated with higher corporate income taxes and higher corporate financing costs associated with the Terasen acquisition.

March 2008/March 2007 – Net earnings applicable to common shares were \$91 million, or \$0.58 per common share, for the first quarter of 2008, up \$49 million from earnings of \$42 million, or \$0.38 per common share, for the first quarter of 2007. Growth in earnings was primarily attributable to the contribution from the Terasen Gas companies, acquired on May 17, 2007, and also reflected improved performance at Caribbean Utilities. The growth was partially offset by higher corporate financing costs associated with the Terasen acquisition and lower earnings at Newfoundland Power associated with a shift in the quarterly distribution of annual purchased power expense. Earnings' contribution from Caribbean Utilities during the first quarter of 2007 was reduced by \$2 million associated with a one-time charge on the disposal of steam-turbine assets.

Management Discussion and Analysis

Management's Evaluation of Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Disclosure Controls and Procedures

The President and Chief Executive Officer ("CEO") and the Vice President, Finance and Chief Financial Officer ("CFO") of Fortis, together with management, have established and maintained disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2008 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

Internal Controls over Financial Reporting

The CEO and the CFO of Fortis, together with management, are also responsible for establishing and maintaining internal controls over financial reporting ("ICFR") within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP. The CEO and CFO of Fortis, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2008 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance.

During the fourth quarter of 2008, there was no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Subsequent Events

In February 2009, FortisAlberta issued \$100 million of 30-year 7.06% unsecured debentures under the short-form base shelf prospectus that was filed in December 2008. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

In February 2009, TGI issued \$100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay \$60 million of unsecured debentures that mature in June 2009.

Outlook

Gross consolidated capital expenditures are estimated to be approximately \$1 billion in 2009 and approximately \$4.5 billion over the next five years. The Corporation's capital program should drive growth in earnings and dividends.

With its substantial credit facilities and conservative capital structure, Fortis believes it has the financial flexibility to respond to the global economic downturn and volatility in the capital markets anticipated to continue in 2009. The Corporation and its utilities also expect to continue to have reasonable access to long-term capital in 2009.

The Corporation continues to pursue acquisitions for profitable growth, focusing on opportunities to acquire regulated natural gas and electric utilities in Canada, the United States and the Caribbean. Fortis will also pursue growth in its non-regulated businesses in support of its regulated utility growth strategy.

Management Discussion and Analysis

Outstanding Share Data

As at March 10, 2009, the Corporation had issued and outstanding 169.8 million common shares; 5.0 million First Preference Shares, Series C; 8.0 million First Preference Shares, Series E; 5.0 million First Preference Shares, Series F; and 9.2 million First Preference Shares, Series G. Only the common shares of the Corporation have voting rights.

The number of common shares that would be issued upon conversion of share options, convertible debt and First Preference Shares, Series C and First Preference Shares, Series E as at March 10, 2009 is as follows:

Conversion of Securities into Common Shares

As at March 10, 2009 (*Unaudited*)

Security	Number of Common Shares (millions)
Stock Options	4.1
Convertible Debt	1.8
First Preference Shares, Series C	6.0
First Preference Shares, Series E	9.7
Total	21.6

Additional information, including the Fortis 2008 Annual Information Form, Management Information Circular and Consolidated Financial Statements, is available on SEDAR at www.sedar.com and on the Corporation's website at www.fortisinc.com.

Management's Report

The accompanying Annual Consolidated Financial Statements of Fortis Inc. and all information in the 2008 Annual Report have been prepared by management, who are responsible for the integrity of the information presented including amounts that must, of necessity, be based on estimates and informed judgments. These Annual Consolidated Financial Statements were prepared in accordance with accounting principles generally accepted in Canada. Financial information contained elsewhere in the 2008 Annual Report is consistent with that in the Annual Consolidated Financial Statements.

In meeting its responsibility for the reliability and integrity of the Annual Consolidated Financial Statements, management has developed and maintains a system of accounting and reporting which provides for the necessary internal controls to ensure transactions are properly authorized and recorded, assets are safeguarded and liabilities are recognized. The systems of the Corporation and its subsidiaries focus on the need for the training of qualified and professional staff and the effective communication of management guidelines and policies. The effectiveness of the internal controls of Fortis Inc. is evaluated on an ongoing basis.

The Board of Directors oversees management's responsibilities for financial reporting through an Audit Committee which is composed entirely of outside independent directors. The Audit Committee oversees the external audit of the Corporation's Annual Consolidated Financial Statements and the accounting and financial reporting and disclosure processes and policies of the Corporation. The Audit Committee meets with management, the shareholders' auditors and the internal auditor to discuss the results of the external audit, the adequacy of the internal accounting controls and the quality and integrity of financial reporting. The Corporation's Annual Consolidated Financial Statements are reviewed by the Audit Committee with each of management and the shareholders' auditors before the statements are recommended to the Board of Directors for approval. The shareholders' auditors have full and free access to the Audit Committee. The Audit Committee has the duty to review the adoption of, and changes in, accounting principles and practices which have a material effect on the Corporation's Annual Consolidated Financial Statements and to review and report to the Board of Directors on policies relating to the accounting and financial reporting and disclosure processes.

The Audit Committee has the duty to review financial reports requiring Board of Directors' approval prior to the submission to securities commissions or other regulatory authorities, to assess and review management judgments material to reported financial information and to review the shareholders' auditors' independence and auditors' fees. The 2008 Annual Consolidated Financial Statements and Management Discussion and Analysis contained in the 2008 Annual Report were reviewed by the Audit Committee and, on their recommendation, were approved by the Board of Directors of Fortis Inc. Ernst & Young, LLP, independent auditors appointed by the shareholders of Fortis Inc. upon the recommendation of the Audit Committee, have performed an audit of the 2008 Annual Consolidated Financial Statements and their report follows.



H. Stanley Marshall
President and Chief Executive Officer
St. John's, Canada



Barry V. Perry
Vice President, Finance and Chief Financial Officer

Auditors' Report

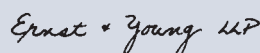
To the Shareholders of Fortis Inc.

We have audited the consolidated balance sheets of Fortis Inc. as at December 31, 2008 and 2007 and the consolidated statements of earnings, retained earnings, comprehensive income and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

St. John's, Canada,
January 30, 2009



Chartered Accountants

Financials

Consolidated Balance Sheets

FORTIS INC.

(Incorporated under the laws of the Province of Newfoundland and Labrador)

As at December 31 (in millions of Canadian dollars)

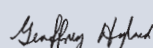
ASSETS	2008	2007
Current assets		
Cash and cash equivalents	\$ 66	\$ 58
Accounts receivable	681	635
Prepaid expenses	17	19
Regulatory assets (Note 4)	157	119
Inventories (Note 5)	229	207
	1,150	1,038
Deferred charges and other assets (Note 6)	279	179
Regulatory assets (Note 4)	203	193
Future income taxes (Note 19)	54	37
Utility capital assets (Note 7)	7,367	6,748
Income producing properties (Note 8)	541	519
Intangibles, net of amortization (Note 2)	9	15
Goodwill (Note 9)	1,575	1,544
	\$ 11,178	\$ 10,273
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings (Note 26)	\$ 410	\$ 475
Accounts payable and accrued charges	874	793
Dividends payable	47	43
Income taxes payable	66	30
Regulatory liabilities (Note 4)	45	20
Current installments of long-term debt and capital lease obligations (Note 10)	240	436
Future income taxes (Note 19)	15	7
	1,697	1,804
Deferred credits (Note 11)	277	261
Regulatory liabilities (Note 4)	401	372
Future income taxes (Note 19)	61	55
Long-term debt and capital lease obligations (Note 10)	4,884	4,623
Non-controlling interest (Note 12)	145	115
Preference shares (Note 13)	320	320
	7,785	7,550
Shareholders' equity		
Common shares (Note 14)	2,449	2,126
Preference shares (Note 13)	347	122
Contributed surplus	9	6
Equity portion of convertible debentures (Note 10)	6	6
Accumulated other comprehensive loss (Note 16)	(52)	(88)
Retained earnings	634	551
	3,393	2,723
	\$ 11,178	\$ 10,273

Commitments (Note 27)

Contingent Liabilities (Note 28)

See accompanying Notes to Consolidated Financial Statements

Approved on Behalf of the Board


Geoffrey F. Hyland,
Director


David G. Norris,
Director

Financials

Consolidated Statements of Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars, except per share amounts)

	2008	2007
Revenue	\$ 3,903	\$ 2,718
Expenses		
Energy supply costs	2,112	1,287
Operating	743	617
Amortization	348	273
	3,203	2,177
Operating Income	700	541
Finance charges (Note 17)	363	299
Gain on sale of property (Note 18)	—	(8)
	363	291
Earnings Before Corporate Taxes and Non-Controlling Interest	337	250
Corporate taxes (Note 19)	65	36
Net Earnings Before Non-Controlling Interest	272	214
Non-controlling interest	13	15
Net Earnings	259	199
Preference share dividends	14	6
Net Earnings Applicable to Common Shares	\$ 245	\$ 193
Earnings Per Common Share (Note 14)		
Basic	\$ 1.56	\$ 1.40
Diluted	\$ 1.52	\$ 1.32

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Retained Earnings

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)

	2008	2007
Balance at Beginning of Year	\$ 551	\$ 486
Net Earnings Applicable to Common Shares	245	193
	796	679
Dividends on Common Shares	(162)	(128)
Balance at End of Year	\$ 634	\$ 551

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Comprehensive Income

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)

	2008	2007
Net Earnings	\$ 259	\$ 199
Unrealized foreign currency translation gains (losses)		
on net investments in self-sustaining foreign operations	115	(70)
(Losses) gains on hedges of net investments in self-sustaining foreign operations	(92)	48
Corporate tax recovery (expense)	13	(9)
Change in Unrealized Foreign Currency Translation Gains (Losses), Net of Hedging Activities and Tax (Note 16)	36	(31)
Comprehensive Income	\$ 295	\$ 168

See accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

FORTIS INC.

For the years ended December 31 (in millions of Canadian dollars)

	2008	2007
Operating Activities		
Net earnings	\$ 259	\$ 199
Items not Affecting Cash		
Amortization – utility capital assets and income producing properties	339	261
Amortization – intangibles and other	9	12
Future income taxes (Note 19)	14	–
Non-controlling interest	13	15
Write-down of deferred power costs – Belize Electricity (Note 4)	18	–
Gain on sale of property (Note 18)	–	(8)
Other	(7)	–
Change in long-term regulatory assets and liabilities	(23)	11
	622	490
Change in non-cash operating working capital	41	(117)
	663	373
Investing Activities		
Change in deferred charges, other assets and deferred credits	(31)	(4)
Utility capital expenditures	(890)	(790)
Contributions in aid of construction	85	73
Income producing property capital expenditures	(14)	(13)
Proceeds on sale of capital assets	18	4
Business acquisitions, net of cash acquired (Note 21)	(22)	(1,303)
	(854)	(2,033)
Financing Activities		
Change in short-term borrowings	(69)	103
Proceeds from long-term debt, net of issue costs	662	797
Repayments of long-term debt and capital lease obligations	(431)	(363)
Net (repayments) borrowings under committed credit facilities	(309)	25
Advances from (to) non-controlling interest	3	(3)
Issue of common shares, net of costs	308	1,267
Issue of preference shares, net of costs	223	–
Dividends		
Common shares	(162)	(128)
Preference shares	(14)	(6)
Subsidiary dividends paid to non-controlling interest	(15)	(12)
	196	1,680
Effect of exchange rate changes on cash and cash equivalents	3	(3)
Change in Cash and Cash Equivalents	8	17
Cash and Cash Equivalents, Beginning of Year	58	41
Cash and Cash Equivalents, End of Year	\$ 66	\$ 58

Supplementary Information to Consolidated Statements of Cash Flows (Note 23)

See accompanying Notes to Consolidated Financial Statements

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

1. Description of the Business

Nature of Operations

Fortis Inc. ("Fortis" or the "Corporation") is principally an international distribution utility holding company. Fortis segments its utility operations by franchise area and, depending on regulatory requirements, by the nature of the assets. Fortis also holds investments in non-regulated generation, and commercial real estate and hotels, which are treated as two separate segments. The Corporation's reporting segments allow senior management to evaluate the operational performance and assess the overall contribution of each segment to the Corporation's long-term objectives. Each reporting segment operates as an autonomous unit, assumes profit and loss responsibility and is accountable for its own resource allocation.

The following summary describes the operations included in each of the Corporation's reportable segments.

Regulated Utilities

The following summary describes the Corporation's interests in regulated gas and electric utilities in Canada and the Caribbean by utility:

Regulated Gas Utilities – Canadian

Terasen Gas Companies: Includes Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGWI"), which Fortis acquired through the acquisition of Terasen Inc. ("Terasen") on May 17, 2007.

TGI is the largest distributor of natural gas in British Columbia, serving primarily residential, commercial and industrial customers in a service area that extends from Vancouver to the Fraser Valley and the interior of British Columbia.

TGVI owns and operates the natural gas transmission pipeline from the Greater Vancouver area across the Georgia Strait to Vancouver Island and the distribution system on Vancouver Island and along the Sunshine Coast of British Columbia, serving primarily residential, commercial and industrial customers.

In addition to providing transmission and distribution services to customers, TGI and TGVI also obtain natural gas supplies on behalf of most residential and commercial customers. Gas supplies are sourced primarily from northeastern British Columbia and, through TGI's Southern Crossing Pipeline, from Alberta.

TGWI owns and operates the propane distribution system in Whistler, British Columbia, providing service to mainly residential and commercial customers.

Regulated Electric Utilities – Canadian

- a. *FortisAlberta:* FortisAlberta owns and operates the electricity distribution system in a substantial portion of southern and central Alberta.
- b. *FortisBC:* Includes FortisBC Inc., an integrated electric utility operating in the southern interior of British Columbia. FortisBC Inc. owns four hydroelectric generating facilities with a combined capacity of 223 megawatts ("MW"). Included with the FortisBC component of the Regulated Electric Utilities – Canadian segment are the operating, maintenance and management services relating to the 450-MW Waneta hydroelectric generating facility owned by Teck Cominco Metals Ltd., the 269-MW Brilliant Hydroelectric Plant owned by Columbia Power Corporation and the Columbia Basin Trust ("CPC/CBT"), the 185-MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT and the distribution system owned by the City of Kelowna.
- c. *Newfoundland Power:* Newfoundland Power is the principal distributor of electricity in Newfoundland. Newfoundland Power has an installed generating capacity of 140 MW, of which 97 MW is hydroelectric generation.
- d. *Other Canadian:* Includes Maritime Electric and FortisOntario. Maritime Electric is the principal distributor of electricity on Prince Edward Island. Maritime Electric also maintains on-Island generating facilities with a combined capacity of 150 MW. FortisOntario provides integrated electric utility service to customers in Fort Erie, Cornwall, Gananoque and Port Colborne in Ontario. FortisOntario's operations primarily include Canadian Niagara Power Inc. ("Canadian Niagara Power") and Cornwall Street Railway, Light and Power Company, Limited ("Cornwall Electric"). Included in Canadian Niagara Power's accounts is the operation of the electricity distribution business of Port Colborne Hydro Inc., which has been leased from the City of Port Colborne under a ten-year lease agreement that expires in April 2012.

Notes to Consolidated Financial Statements

Regulated Electric Utilities – Caribbean

- a. *Belize Electricity*: Belize Electricity is the principal distributor of electricity in Belize, Central America. The Company has an installed generating capacity of 34 MW. Fortis holds an approximate 70 per cent controlling ownership interest in Belize Electricity.
- b. *Caribbean Utilities*: Caribbean Utilities is the sole provider of electricity on Grand Cayman, Cayman Islands. The Company has an installed generating capacity of 137 MW. Fortis has an approximate 57 per cent controlling ownership interest in Caribbean Utilities. Caribbean Utilities is a public company traded on the Toronto Stock Exchange (TSX:CUP.U). Caribbean Utilities had an April 30 fiscal year end whereby, up to and including the third quarter of 2008, its financial statements were consolidated in the financial statements of Fortis on a two-month lag basis. Caribbean Utilities changed its fiscal year end to December 31, which has resulted in the Corporation consolidating 14 months of financial results of Caribbean Utilities during 2008. The impact on 2008 earnings was not material. Going forward, this change in the Company's fiscal year end will eliminate the previous two-month lag in consolidating Caribbean Utilities' financial results.
- c. *Fortis Turks and Caicos*: Includes P.P.C. Limited ("PPC") and Atlantic Equipment & Power (Turks and Caicos) Ltd. ("Atlantic"). Fortis Turks and Caicos is the principal distributor of electricity on the Turks and Caicos Islands. The Company has a combined diesel-fired generating capacity of 48 MW.

Non-Regulated – Fortis Generation

- a. *Belize*: Operations consist of the 25-MW Mollejon and 7-MW Chalillo hydroelectric generating facilities in Belize. All of the output of these facilities is sold to Belize Electricity under a 50-year power purchase agreement expiring in 2055. The hydroelectric generation operations in Belize are conducted through the Corporation's indirect wholly owned subsidiary Belize Electric Company Limited ("BECOL") under a franchise agreement with the Government of Belize.
- b. *Ontario*: Includes 75 MW of water-right entitlement associated with the Niagara Exchange Agreement, which expires April 30, 2009; a 5-MW gas-fired cogeneration plant in Cornwall; and six small hydroelectric generating stations in eastern Ontario with a combined capacity of 8 MW.
- c. *Central Newfoundland*: Through the Exploits River Hydro Partnership ("Exploits Partnership"), a partnership between the Corporation, through its wholly owned subsidiary Fortis Properties, and Abitibi-Consolidated Company of Canada ("Abitibi-Consolidated"), 36 MW of additional capacity was developed and installed at two of Abitibi-Consolidated's hydroelectric generating plants in central Newfoundland. Fortis Properties holds directly a 51 per cent interest in the Exploits Partnership and Abitibi-Consolidated holds the remaining 49 per cent interest. The Exploits Partnership sells its output to Newfoundland and Labrador Hydro Corporation under a 30-year power purchase agreement expiring in 2033 (Note 28).
- d. *British Columbia*: Includes the 16-MW run-of-river Walden hydroelectric power plant near Lillooet, British Columbia. This plant sells its entire output to BC Hydro under a long-term contract expiring in 2013.
- e. *Upper New York State*: Includes the operations of four hydroelectric generating stations in Upper New York State, with a combined capacity of approximately 23 MW, operating under licences from the US Federal Energy Regulatory Commission. Hydroelectric generation operations in Upper New York State are conducted through the Corporation's indirect wholly owned subsidiary FortisUS Energy Corporation ("FortisUS Energy").

Non-Regulated – Fortis Properties

Fortis Properties owns and operates 20 hotels comprised of more than 3,800 rooms in eight Canadian provinces and approximately 2.8 million square feet of commercial real estate primarily in Atlantic Canada.

Corporate and Other

The Corporate and Other segment captures expense and revenue items not specifically related to any reportable segment. This segment includes finance charges, including interest on debt incurred directly by Fortis and Terasen Inc. and dividends on preference shares classified as long-term liabilities; dividends on preference shares classified as equity; other corporate expenses, including Fortis and Terasen Inc. corporate operating costs, net of recoveries from subsidiaries; interest and miscellaneous revenues; and corporate income taxes.

Also included in the Corporate and Other segment are the financial results of CustomerWorks Limited Partnership ("CWLP"). CWLP is a non-regulated shared-services business in which Terasen holds a 30 per cent interest. CWLP operates in partnership with Enbridge Inc. and provides customer service contact, meter reading, billing, credit, support and collection services to the Terasen Gas companies and several smaller third parties. CWLP's financial results are recorded using the proportionate consolidation method of accounting. While currently not significant, financial results of Terasen Energy Services Inc. ("TES") are also reported in the Corporate and Other segment. TES is a non-regulated wholly owned subsidiary of Terasen that provides alternative energy solutions.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), including selected accounting treatments that differ from those used by entities not subject to rate regulation. The timing of the recognition of certain assets, liabilities, revenue and expenses, as a result of regulation, may differ from that otherwise expected using Canadian GAAP by entities not subject to rate regulation. The differences are described in Note 2 under the headings "Regulation", "Utility Capital Assets", "Employee Future Benefits", "Income Taxes" and "Revenue Recognition", and in Note 4.

All amounts presented are in Canadian dollars unless otherwise stated.

Regulation

Terasen Gas Companies and FortisBC

The Terasen Gas companies and FortisBC are regulated by the British Columbia Utilities Commission ("BCUC"). The BCUC administers acts and regulations pursuant to the *Utilities Commission Act* (British Columbia), covering such matters as tariffs, rates, construction, operations, financing and accounting. TGI, TGVI and FortisBC operate under both cost-of-service regulation and performance-based rate-setting ("PBR") methodologies as administered by the BCUC. The BCUC provides for the use of a future test year in the establishment of rates and, pursuant to this method, provides for the forecasting of energy to be sold, together with all the costs of the utilities, and provides a rate of return on a deemed capital structure applied to approved rate base assets. Rates are fixed to permit the utilities to collect all of their costs, including the allowed rate of return on common shareholders' equity ("ROE").

Under the PBR mechanism, TGI and customers equally share in achieved earnings above or below the allowed ROE. When TGI's earned ROE is greater than 200 basis points above the allowed ROE for two consecutive years, the PBR mechanism may be reviewed. Under the PBR mechanism, TGVI is permitted to retain 100 per cent of earnings derived from lower-than-forecasted controllable operating and maintenance expenses; however, TGVI is not provided any relief from increased controllable operating and maintenance expenses. The PBR agreements at TGI and TGVI have been extended until 2009. During 2008, the BCUC extended the PBR agreement for FortisBC for the years 2009 through 2011. Under the PBR agreement, FortisBC and customers equally share achieved earnings above or below the allowed ROE up to an achieved ROE that is 200 basis points above or below the allowed ROE. Any excess is subject to deferral treatment. FortisBC's portion of the PBR incentive is subject to the Company meeting certain performance standards and BCUC approval.

TGI's allowed ROE was 8.62 per cent for 2008 (2007 – 8.37 per cent) on a deemed capital structure of 35 per cent common equity. TGVI's allowed ROE was 9.32 per cent for 2008 (2007 – 9.07 per cent) on a deemed capital structure of 40 per cent common equity. FortisBC's allowed ROE was 9.02 per cent for 2008 (2007 – 8.77 per cent) on a deemed capital structure of 40 per cent common equity. The allowed ROE at each of TGI, TGVI and FortisBC is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. TGI, TGVI and FortisBC apply for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment and/or through the operation of the PBR mechanisms.

FortisAlberta

FortisAlberta is regulated by the Alberta Utilities Commission ("AUC"), pursuant to the *Electric Utilities Act* (Alberta), the *Public Utilities Board Act* (Alberta), the *Hydro and Electric Energy Act* (Alberta) and the *AUC Act* (Alberta). The AUC administers these acts and regulations, covering such matters as tariffs, rates, construction, operations and financing.

FortisAlberta operates under cost-of-service regulation as prescribed by the AUC. The AUC provides for the use of a future test year in the establishment of rates associated with the distribution business and, pursuant to this method, rate orders issued by the AUC establish the Company's revenue requirements, being those revenues required to recover approved costs associated with the distribution business and provide a rate of return on a deemed capital structure applied to approved rate base assets. FortisAlberta's allowed ROE was 8.75 per cent for 2008 (2007 – 8.51 per cent) on a deemed capital structure of 37 per cent common equity. FortisAlberta's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Newfoundland Power

Newfoundland Power is regulated by the Newfoundland and Labrador Board of Commissioners of Public Utilities ("PUB") under the *Public Utilities Act* (Newfoundland and Labrador). The *Public Utilities Act* (Newfoundland and Labrador) provides for the PUB's general supervision of the Company's utility operation and requires the PUB to approve, among other things, customer rates, capital expenditures and the issuance of securities of Newfoundland Power. Newfoundland Power operates under cost-of-service regulation as administered by the PUB. The PUB provides for the use of a future test year in the establishment of rates for the utility and, pursuant to this method,

Notes to Consolidated Financial Statements

the determination of the forecast rate of return on approved rate base and deemed capital structure, together with the forecast of all reasonable and prudent costs, establish the revenue requirement upon which Newfoundland Power's customer rates are determined. Between test years, Newfoundland Power's allowed ROE is adjusted annually through the operation of an automatic adjustment formula to adjust for forecast changes in long-term Canada bond yields. Newfoundland Power's allowed ROE for 2008 was 8.95 per cent (2007 – 8.60 per cent) on a deemed capital structure of 45 per cent common equity. The Company applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

Maritime Electric

Maritime Electric operates under a traditional cost-of-service regulatory model as prescribed by the Island Regulatory and Appeals Commission ("IRAC") under the provisions of the *Electric Power Act* (Prince Edward Island). IRAC uses a future test year in the establishment of rates for the utility and, pursuant to this method, rate orders are based on estimated costs and provide an approved rate of return on a deemed capital structure applied to approved rate base assets. Maritime Electric's allowed ROE was 10.00 per cent for 2008 (2007 – 10.25 per cent) on a deemed capital structure of 40 per cent common equity. Maritime Electric applies for tariff revenue based on estimated cost of service. Once the tariff is approved, it is not adjusted as a result of actual cost of service being different from that which was estimated, other than for certain prescribed costs that are eligible for deferral account treatment.

FortisOntario

Canadian Niagara Power and Cornwall Electric operate under the *Electricity Act* (Ontario) and the *Ontario Energy Board Act* (Ontario) as administered by the Ontario Energy Board ("OEB"). Canadian Niagara Power operates under cost-of-service regulation and earnings are regulated on the basis of rate of return on rate base, plus a recovery of allowable distribution costs. In 2008, the utility's electricity distribution rates were based upon costs derived from a 2004 test year using a deemed capital structure of 46.7 per cent common equity. In accordance with the OEB's plan, the utility will move to a 40 per cent common equity capital structure over a three-year period. FortisOntario's allowed ROE was 9 per cent for 2008 (2007 – 9 per cent).

Cornwall Electric is exempt from many aspects of the above Acts and is also subject to a 35-year Franchise Agreement with the City of Cornwall, expiring in 2033. The rate-setting mechanism is subject to a price cap with commodity cost flow through. The base revenue requirement is adjusted annually for inflation, load growth and customer growth.

Belize Electricity

Belize Electricity is regulated by the Public Utilities Commission ("PUC") under the terms of the *Electricity Act* (Belize), the *Electricity (Tariffs, Charges and Quality of Service Standards) By-Laws* (Belize) and the *Public Utilities Commission Act* (Belize). The PUC oversees the rates that may be charged in respect of utility services and the standards that must be maintained in relation to such services and uses a future test year to set rates. In addition, the PUC is responsible for the award of licences and for monitoring and enforcing compliance with licences' conditions. The basic electricity rate at Belize Electricity is comprised of two components. The first component is value-added delivery ("VAD") and the second is the cost of fuel and purchased power ("COP"), including the variable cost of generation, which is a flow through in customer rates. The VAD component of the tariff allows the Company to recover its operating expenses, transmission and distribution expenses, taxes and amortization, and an allowed rate of return on rate base assets ("ROA"). Belize Electricity's allowed ROA was set at 10.00 per cent effective July 1, 2008 (2007 – 10.00 to 15.00 per cent).

Caribbean Utilities

Caribbean Utilities has been generating and distributing electricity in its franchise area of Grand Cayman, Cayman Islands, under a licence from the Government of the Cayman Islands (the "Government") since May 10, 1966. Effective January 1, 2008, new licences were granted to Caribbean Utilities. The new exclusive transmission and distribution ("T&D") licence is for an initial period of 20 years, expiring April 2028, with a provision for automatic renewal. The new generation licence is for a period of 21.5 years, expiring September 2029. The new licences establish a rate cap and adjustment mechanism ("RCAM") based on published consumer price indices. Customer rates are set using an initial targeted allowed ROA of 10 per cent, down from an allowed ROA of 15 per cent that was permitted under the previous licence. The new licences detail the role of the Electric Regulatory Authority, which will oversee all licences, establish and enforce licence standards, review the RCAM and annually approve capital expenditures.

Fortis Turks and Caicos

Fortis Turks and Caicos provides electricity to Providenciales, North Caicos and Middle Caicos through PPC and provides electricity to South Caicos through Atlantic for terms of 50 years under licences dated October 1987 and November 1986 (collectively, the "Agreements"), respectively. Among other matters, these Agreements describe how electricity rates are to be set by the Government of the Turks and Caicos Islands, using a future test year, in order to provide Fortis Turks and Caicos with an allowed ROA of 17.5 per cent (the "Allowable Operating Profit") based on a calculated rate base, and including interest on the amounts by which actual operating profits fall short of Allowable Operating Profits on a cumulative basis (the "cumulative shortfall").

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December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (cont'd)

Regulation (cont'd)

Fortis Turks and Caicos makes annual submissions to the Government of the Turks and Caicos Islands calculating the amount of the Allowable Operating Profit and the cumulative shortfalls. The submissions for 2008 calculated the Allowable Operating Profit for 2008 to be \$22 million (US\$18 million) and the cumulative shortfall at December 31, 2008 to be \$22 million (US\$18 million). Fortis Turks and Caicos has a legal right under the Agreements to request an increase in electricity rates to begin to recover the cumulative shortfalls. The recovery would, however, be dependent on future sales volumes and expenses.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term deposits with maturities of three months or less from the date of acquisition.

Inventories

Inventories are valued at the lower of weighted-average cost and net realizable value.

Utility Capital Assets

Utility capital assets of Newfoundland Power are stated at values approved by the PUB as at June 30, 1966 with subsequent additions at cost. Utility capital assets of Caribbean Utilities are stated on the basis of appraised values as at November 30, 1984 with subsequent additions at cost. Utility capital assets of Fortis Turks and Caicos are stated at appraised values as at September 18, 1986. Subsequent additions are at cost except for the distribution systems on Middle, North and South Caicos, transferred by the Government of the Turks and Caicos Islands to Fortis Turks and Caicos by agreements dated November 29, 1986 and October 8, 1987 for US\$2.00, in aggregate, as valued in the books of the companies. Utility capital assets of all other utility operations are stated at cost.

Contributions in aid of construction represent amounts contributed by customers and governments for the cost of utility capital assets. These contributions are recorded as a reduction in the cost of utility capital assets and are being reduced annually by an amount equal to the charge for amortization provided on the related assets.

As required by their respective regulators, amortization expense at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric includes an amount allowed for regulatory purposes to provide for future asset removal and site restoration costs, net of salvage proceeds. The amount provided for in amortization expense is recorded as a long-term regulatory liability. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred. At December 31, 2008, the long-term regulatory liability for future asset removal and site restoration costs was \$337 million (December 31, 2007 – \$319 million) (Note 4 (xii)). The Terasen Gas companies record actual asset removal and site restoration costs, net of salvage proceeds, against accumulated amortization. In the absence of a current depreciation study approved by its regulator, a reasonable estimate of any regulatory asset or liability associated with future asset removal and site restoration costs for the Terasen Gas companies cannot be made as at December 31, 2008. FortisOntario, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos record asset removal and site restoration costs in earnings when incurred, and these costs did not have a material impact on the Corporation's 2008 and 2007 earnings.

Upon retirement or disposal of utility capital assets, the capital cost of the assets is charged to accumulated amortization by the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities, as required by their respective regulators, with no loss, if any, reflected in earnings. It is expected that any loss charged to accumulated amortization will be reflected in future amortization expense when it is collected in customer gas and electricity rates. At FortisOntario and Fortis Turks and Caicos, any remaining net book value, less salvage proceeds, upon retirement or disposal of utility capital assets is recorded immediately in earnings. In the absence of rate regulation, any loss on the retirement or disposal of utility capital assets at the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and Belize Electricity would be recognized in the current period. The loss charged to accumulated amortization in 2008 was approximately \$31 million (2007 – \$26 million).

Utility capital assets include inventories held for the development, construction and maintenance of other utility capital assets. When put into service, the inventories are amortized using the straight-line method based on estimated service lives of the capital assets to which they are added.

Maintenance and repairs of utility capital assets are charged to earnings in the period incurred while replacements and betterments are capitalized.

Notes to Consolidated Financial Statements

As required by their respective regulators, the Terasen Gas companies, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Belize Electricity and, commencing May 2008, Caribbean Utilities capitalize overhead costs that are not directly attributable to specific utility capital assets but which relate to the overall capital expenditure program. The methodology for calculating and allocating capitalized general overhead costs to utility capital assets is established by the respective regulators. In the absence of rate regulation, only those overhead costs directly attributable to construction activity would be capitalized. The general expenses capitalized ("GEC") are allocated over constructed capital assets and amortized over their estimated service lives. In 2008, GEC totalled \$57 million (2007 – \$42 million).

As required by their respective regulators, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, Belize Electricity and, commencing May 2008, Caribbean Utilities include an equity component in the allowance for funds used during construction ("AFUDC") that is included in the cost of utility capital assets. Since AFUDC includes both an interest component and an equity component, it exceeds the amount allowed to be capitalized in similar circumstances by entities not subject to rate regulation. AFUDC is deducted from finance charges and AFUDC capitalized during 2008 was \$13 million (2007 – \$8 million) (Note 17), including an equity component of \$6 million (2007 – \$3 million). AFUDC is charged to operations through amortization expense over the estimated service lives of the applicable utility capital assets.

FortisAlberta maintains a regulatory tax basis adjustment account, which represents the excess of the deemed tax basis of the Company's utility capital assets for regulatory rate-making purposes as compared to the Company's tax basis for income tax purposes. The regulatory tax basis adjustment is being amortized over the estimated service lives of the Company's utility capital assets by an offset against the provision for amortization. The regulatory tax basis adjustment is recorded as a reduction in utility capital assets. During 2008, amortization expense was reduced by \$4 million (2007 – \$5 million) for the amortization of the regulatory tax basis adjustment.

Utility capital assets are being amortized using the straight-line method based on the estimated service lives of the capital assets. Amortization rates range from 0.4 per cent to 39.0 per cent. The composite rate of amortization before reduction for amortization of contributions in aid of construction for 2008 was 3.5 per cent (2007 – 3.6 per cent).

The service life ranges and average remaining service life of the Corporation's distribution, transmission, generation and other assets as at December 31 were as follows.

	2008		2007	
	Service Life Ranges (Years)	Average Remaining Service Life (Years)	Service Life Ranges (Years)	Average Remaining Service Life (Years)
Distribution				
Gas	10–100	35	10–100	33
Electricity	5–75	28	10–75	28
Transmission				
Gas	10–50	37	10–50	38
Electricity	10–75	35	10–75	34
Generation	5–75	29	5–75	32
Other	5–67	14	5–67	14

Income Producing Properties

Income producing properties of Fortis Properties, which include office buildings, shopping malls, hotels, land and related equipment and tenant inducements, are recorded at cost. Buildings are being amortized using the straight-line method over an estimated useful life of 60 years. Fortis Properties amortizes tenant inducements over the initial terms of the leases to which they relate. The lease terms vary to a maximum of 20 years. Equipment is recorded at cost and is amortized on a straight-line basis over a range of 2 years to 25 years.

Maintenance and repairs of income producing properties are charged to earnings in the period incurred while replacements and betterments are capitalized.

Leases

Leases which transfer to the Corporation substantially all of the risks and benefits incidental to ownership of the leased item are capitalized at the present value of the minimum lease payments. Capital leases are depreciated over the lease term. Operating lease payments are recognized as an expense in earnings on a straight-line basis over the lease term.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (cont'd)

Intangibles

Intangibles include the estimated fair value of water rights associated with the Rankine hydroelectric generating station in Ontario and intangibles associated with the acquisition of Terasen. The Rankine water rights are being amortized using the straight-line method over the estimated life of the asset to April 30, 2009. As at April 30, 2009, in accordance with the Niagara Exchange Agreement, the Corporation's water entitlement on the Niagara River associated with the Rankine hydroelectric generating station will expire and associated earnings' contribution will cease.

Upon the acquisition of Terasen, \$10 million was assigned as the value associated with customer contracts at CWLP. The intangible is being amortized using the straight-line method over the remaining term of the contracts to December 31, 2011. Approximately \$1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

As at December 31, 2008, the net book value of intangibles was \$9 million (net of accumulated amortization of \$28 million) (December 31, 2007 – \$15 million (net of accumulated amortization of \$21 million)).

Impairment of Long-Lived Assets

The Corporation reviews the valuation of utility capital assets, income producing properties, intangible assets with finite lives and deferred charges and other assets when events or changes in circumstances may indicate that the asset's carrying value exceeds the total undiscounted cash flows expected from its use and eventual disposition. An impairment loss, calculated as the difference between the asset's carrying value and its fair value, which is determined using present value techniques, is recognized in earnings in the period in which it is identified. There was no impact on the consolidated financial statements as a result of asset impairments for the years ended December 31, 2008 and 2007.

The process for asset-impairment testing differs for non-regulated generation assets compared to regulated utility assets. Since each non-regulated generating facility provides an individual cash inflow stream, such an asset is tested individually and an impairment is recorded if the future cash inflows are no longer sufficient to recover the carrying value of the generating facility. Asset-impairment testing at the regulated utilities is carried out at the enterprise level to determine if assets are impaired. The recovery of a regulated asset's carrying value, including a fair return on capital or assets, is provided through customer gas and electricity rates approved by the respective regulatory authorities. The cash inflows for regulated enterprises are not asset-specific but are pooled for the entire regulated enterprise.

Goodwill

Goodwill represents the excess, at the dates of acquisition, of the purchase price over the fair value of the net amounts assigned to individual assets acquired and liabilities assumed relating to business acquisitions. Goodwill is carried at initial cost less any previous amortization and any write-down for impairment. The Corporation is required to perform an annual impairment test and any impairment provision is charged to earnings. To assess for impairment, the fair value of each of the Corporation's reporting units is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment. The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit, to determine the implied fair value of goodwill, and then by comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of the goodwill over the implied fair value of the goodwill is the impairment amount. In addition to the annual impairment test, the Corporation also performs an impairment test if any event occurs or if circumstances change that would indicate that the fair value of a reporting unit was below its carrying value. No goodwill impairment provision has been determined for the years ended December 31, 2008 and 2007.

Employee Future Benefits

Defined Benefit and Defined Contribution Pension Plans

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group Registered Retirement Savings Plans ("RRSPs") for its employees. The costs of the defined contribution pension plans and RRSPs are expensed as incurred. The accrued pension benefit obligation and the value of pension costs of the defined benefit pension plans are actuarially determined using the projected benefits method prorated on service and management's best estimate of the discount rate, expected plan investment performance, salary escalation and retirement ages of employees.

Notes to Consolidated Financial Statements

With the exception of the Terasen Gas companies and Newfoundland Power, pension plan assets are valued at fair value. At the Terasen Gas companies and Newfoundland Power, plan assets are valued using the market-related value, where investment returns in excess of or below expected returns are recognized in the asset value over a period of three years. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the greater of the benefit obligation and the fair value of plan assets (the market-related value of plan assets at the Terasen Gas companies and Newfoundland Power), at the beginning of the fiscal year, along with unamortized past service costs, are deferred and amortized over the average remaining service period of active employees.

On January 1, 2000, Newfoundland Power prospectively applied Section 3461 of the Canadian Institute of Chartered Accountants' ("CICA") Handbook. The Company is amortizing the resulting transitional obligation on a straight-line basis over 18 years, the expected average remaining service period of the plan members at that time.

As approved by the regulator, the cost of defined benefit pension plans at FortisAlberta is being recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for defined benefit and defined contribution pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 (viii) and (xvii)).

Supplementary and Other Post-Employment Benefit ("OPEB") Plans

The Corporation, the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer other non-pension post-employment benefits through defined benefit plans, including certain health and dental coverage, for qualifying members.

Additionally, the Corporation, Terasen Gas companies, FortisAlberta, Newfoundland Power and Maritime Electric provide retirement allowances and supplemental retirement plans for certain of its executive employees. The accrued benefit obligation and the value of the costs associated with the supplementary and OPEB plans are actuarially determined using the projected benefits method prorated on service and best-estimate assumptions. The excess of any cumulative net actuarial gain (loss) over 10 per cent of the benefit obligation, at the beginning of the fiscal year, and any unamortized past service costs are deferred and amortized over the average remaining service period of active employees.

As approved by the respective regulators, the costs of OPEB plans at FortisAlberta and Newfoundland Power are recovered in customer rates based on the cash payments made, with the exception of retirement allowances arising from Newfoundland Power's 2005 Early Retirement Program. The cost of supplemental pension plans at FortisAlberta is also recovered in customer rates based on the cash payments made.

Any difference between the expense recognized under Canadian GAAP and that recovered from customers in current rates for OPEB and supplemental pension plans, which is expected to be recovered, or refunded, in future customer rates, is subject to deferral treatment (Note 4 (iv)).

Stock-Based Compensation

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 Stock Option Plan ("2002 Plan") and 2006 Stock Option Plan ("2006 Plan") (Note 15). Compensation expense is measured at the date of grant using the Black-Scholes fair value option-pricing model and is amortized over the four-year vesting period of the options granted. The offsetting entry is an increase to contributed surplus for an amount equal to the annual compensation expense related to the issuance of stock options. Upon exercise, the proceeds of the options are credited to capital stock at the option prices, and the fair value of the options, as previously recorded, is reclassified from contributed surplus to capital stock. An exercise of options below the current market price has a dilutive effect on capital stock and shareholders' equity.

The Corporation also records compensation expense associated with its Directors' Deferred Share Unit ("DSU") and Performance Share Unit ("PSU") Plans using the fair value method, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU and PSU liabilities is based on the Corporation's common share closing price at the end of each reporting period.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (cont'd)

Foreign Currency Translation

The assets and liabilities of foreign operations, all of which are self-sustaining and denominated in US dollars or in a currency pegged to the US dollar, are translated at the exchange rate in effect at the balance sheet dates. Belize Electricity's reporting currency is the Belizean dollar, while the reporting currency of Caribbean Utilities, FortisUS Energy, BECOL and Fortis Turks and Caicos is the US dollar. The Belizean dollar is pegged to the US dollar at BZ\$2.00 = US\$1.00. The exchange rate in effect at December 31, 2008 was US\$1.00 = CDN\$1.22 (December 31, 2007 – US\$1.00 = CDN\$0.99). The resulting unrealized translation gains and losses are accumulated as a separate component of shareholders' equity within accumulated other comprehensive loss and the current period change is recorded in other comprehensive income. Revenue and expense items are translated at the average exchange rate in effect during the period.

Foreign exchange translation gains and losses on foreign currency-denominated long-term debt that is designated as an effective hedge of foreign net investments are recorded separately in other comprehensive income.

Monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate prevailing on the balance sheet date. Revenue and expense items denominated in foreign currencies are translated at the exchange rate prevailing on the transaction date. Gains and losses on translation are included in earnings.

Financial Instruments

The Corporation designates its financial instruments into one of the following five categories: (i) held for trading, (ii) available for sale, (iii) held to maturity, (iv) loans and receivables, or (v) other financial liabilities. All financial instruments are initially measured at fair value. Financial instruments classified as held for trading or available for sale are subsequently measured at fair value with any change in fair value recorded in earnings and other comprehensive income, respectively. All other financial instruments are subsequently measured at amortized cost.

Derivative financial instruments, including derivative features embedded in financial instruments or other contracts that are not considered closely related to the host financial instrument or contract, are generally classified as held for trading and, therefore, must be measured at fair value with changes in fair value recorded in earnings. If a derivative financial instrument is designated as a hedging item in a qualifying cash flow hedging relationship, the effective portion of changes in fair value is recorded in other comprehensive income. Any change in fair value relating to the ineffective portion is recorded immediately in earnings. At the Terasen Gas companies, any difference between the amount recognized upon a change in the fair value of a derivative financial instrument, whether or not in a qualifying hedging relationship, and the amount recovered from customers in current rates is subject to regulatory deferral treatment to be recovered from, or refunded to, customers in future rates (Note 4 (xvi)). Currently, the Corporation limits the use of derivative financial instruments to those that qualify as hedges, as discussed under "Hedging Relationships".

The Corporation has selected January 1, 2003 as the transition date for recognizing embedded derivatives and, therefore, recognizes as separate assets and liabilities only those derivatives embedded in hybrid instruments issued, acquired or substantially modified on or after January 1, 2003. While some of the Corporation's long-term debt contracts have prepayment options that qualify as embedded derivatives to be separately recorded, none have been recorded as they are immaterial to the Corporation's results of operations and financial position.

The Corporation's policy is to recognize transaction costs associated with financial assets and liabilities, that are classified as other than held for trading, as an adjustment to the cost of those financial assets and liabilities recorded on the balance sheet. These transaction costs are amortized into earnings using the effective interest rate method over the life of the related financial instrument.

Effective January 1, 2008, the Corporation has adopted CICA Handbook Section 3862, *Financial Instruments – Disclosures* and Section 3863, *Financial Instruments – Presentation*, which require disclosures of both qualitative and quantitative information that enables users of financial statements to evaluate the nature and extent of risks from financial instruments to which the Corporation is exposed. The new disclosures are provided in Notes 25 and 26.

Hedging Relationships

At December 31, 2008, the Corporation's hedging relationships consisted of interest rate swap contracts, a foreign exchange forward contract, natural gas derivatives and US dollar borrowings. Derivative financial instruments are used only to manage risk and are not used for trading purposes.

Notes to Consolidated Financial Statements

Fortis Properties has designated its interest rate swap contracts as hedges of the cash flow risk related to floating-rate long-term debt. The interest rate swap contracts are valued at the present value of future cash flows based on published forward future interest rate curves. The fair value and subsequent changes in fair value of interest rate swap contracts that are in effective hedging relationships are recorded in other comprehensive income.

The foreign exchange forward contract is held by TGVI and is designated as a hedge of the cash flow risk related to approximately US\$55 million required to be paid under a contract for the construction of a liquefied natural gas ("LNG") storage facility. The foreign exchange forward contract is valued at the present value of future cash flows based on published forward future foreign exchange market rate curves. Any change in the fair value of the foreign exchange forward contract is deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The natural gas derivatives are used to fix the effective purchase price of natural gas, as the majority of the natural gas supply contracts at the Terasen Gas companies have floating, rather than fixed, prices. The fair values of the natural gas derivatives reflect the estimated amounts, based on published forward curves, that the Corporation would have to receive or pay if forced to settle all outstanding contracts at the balance sheet date. As at December 31, 2008, none of the natural gas derivatives were designated as hedges of the natural gas supply contracts. However, any changes in the fair value of the natural gas derivatives are deferred as a regulatory asset or liability for recovery from, or refund to, customers in future rates, as permitted by the regulator.

The Corporation's earnings from and net investments in self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The Corporation has designated its corporately held US dollar long-term debt as a hedge of the foreign exchange risk related to its net investments in self-sustaining foreign subsidiaries. The unrealized foreign exchange gains and losses on the US dollar-denominated long-term debt and the partially offsetting unrealized foreign exchange losses and gains on the foreign net investments are recognized in other comprehensive income.

Income Taxes

Except as described below for the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power, the Corporation and its subsidiaries follow the asset and liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for temporary differences between the tax and accounting basis of assets and liabilities, as well as for the benefit of losses available to be carried forward to future years for tax purposes that are likely to be realized. The future income tax assets and liabilities are measured using the enacted or substantively enacted income tax rates and laws that will be in effect when the differences are expected to be recovered or settled. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period that the change occurs. Current income tax expense (recovery) is recognized for the estimated income taxes payable (receivable) in the current year.

The Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power follow the cash taxes payable method of accounting for income taxes, as prescribed by their respective regulators. Under this methodology, except for certain deferred accounts specifically prescribed by the respective regulators, current customer rates do not include the recovery of future income taxes related to certain temporary differences between the tax basis of assets and liabilities and their carrying amounts for regulatory purposes, as these taxes are expected to be collected in customer rates when they become payable.

Entities not subject to rate regulation generally recognize future income tax assets and liabilities for temporary differences between the tax and accounting basis of all assets and liabilities. In the absence of rate regulation, future income tax assets and liabilities would have been recorded and the Corporation's future income tax liabilities and future income tax assets would have increased by approximately \$364 million and \$18 million, respectively, as at December 31, 2008 (December 31, 2007 – \$344 million and \$29 million, respectively).

Belize Electricity is subject to corporate tax; however, it is capped at 1.75 per cent of gross revenues. Caribbean Utilities and Fortis Turks and Caicos are not subject to income tax as they operate in tax-free jurisdictions. BECOL is not subject to income tax as it was granted tax-exempt status by the Government of Belize for the term of the 50-year power purchase agreement.

The Corporation does not provide for income taxes on undistributed earnings of foreign subsidiaries that are not expected to be repatriated in the foreseeable future.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

2. Summary of Significant Accounting Policies (cont'd)

Revenue Recognition

Revenue at the Corporation's regulated utilities is recognized in a manner approved by each utility's regulatory authority. Revenue at the regulated utilities is billed at rates approved by the applicable regulatory authorities and is generally bundled to include service associated with generation, transmission and distribution, except at FortisAlberta and FortisOntario.

Transmission is the conveyance of gas at high pressures (generally at 2,070 kilopascals ("kPa") and higher) and electricity at high voltages (generally at 69 kilovolts ("kV") and higher). Distribution is the conveyance of gas at lower pressures (generally below 2,070 kPa) and electricity at lower voltages (generally below 69 kV). Distribution networks convey gas and electricity from transmission systems to end-use customers.

As required by the respective regulatory authorities, revenue from the sale of gas by the Terasen Gas companies and electricity by FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric, FortisOntario, Caribbean Utilities and Fortis Turks and Caicos is recognized on the accrual basis. Gas and electricity are metered upon delivery to customers and recognized as revenue using approved rates when consumed. Meters are read periodically and bills are issued to customers based on these readings. At the end of each period, a certain amount of consumed gas and electricity will not have been billed. Gas and electricity consumed but not yet billed to customers are estimated and accrued as revenue at each period end.

As required by the PUC, revenue from the sale of electricity by Belize Electricity is recognized as monthly billings are rendered to customers. In the absence of rate regulation, revenue would be recorded on an accrual basis. The difference between recognizing revenue on a billed versus an accrual basis is recorded on the balance sheet as a regulatory liability (Note 4 (xiii)).

FortisAlberta reports revenue and expenses related to transmission services on a net basis in revenue. At the Corporation's other regulated utilities, transmission revenue and expenses are recorded on a gross basis. As stipulated by the AUC, FortisAlberta is required to arrange and pay for transmission service with Alberta Electric System Operator ("AESO") and collect transmission revenue from its customers, which is achieved through invoicing the customers' retailers through FortisAlberta's transmission component of its AUC-approved rates. FortisAlberta is solely a distribution company and, as such, does not operate or provide any transmission or generation services. The Company is a conduit for the flow through of transmission costs to end-use customers, as the transmission provider does not have a direct relationship with these customers. The rates collected are based on forecasted transmission expenses and, for certain elements of the transmission costs, FortisAlberta is subject to the risk of actual expenses being different from the forecast revenue relating to transmission services. All other differences are subject to deferral treatment and are either collected, or refunded, in future customer rates (Note 4 (iii)).

FortisOntario's regulated operations are primarily comprised of the operations of Cornwall Electric and Canadian Niagara Power. Electricity rates at Cornwall Electric are bundled due to the nature of the Franchise Agreement with the City of Cornwall. Electricity rates at Canadian Niagara Power are not bundled. At Canadian Niagara Power, the cost of power and transmission are a flow through to customers and these costs and revenue associated with the recovery of these costs are tracked and recorded separately. This treatment is consistent with other regulated utilities in Ontario as required under OEB regulation. The amount of transmission revenue tracked separately at Canadian Niagara Power is not significant in relation to the consolidated revenue of Fortis.

All of the Corporation's non-regulated generation operations record revenue on an accrual basis and revenue is recognized on delivery of output at rates fixed under contract or based on observed market prices as stipulated in contractual arrangements. Generally, production from the Corporation's generation stations is metered at or near month end and production data is used to record revenue earned.

Hospitality revenue is recognized when services are provided. Real estate revenue is derived from leasing retail and office space to tenants for varying periods of time. Revenue is recorded in the month that it is earned at rates in accordance with lease agreements. The leases are primarily of a net nature, with tenants paying basic rental plus a pro rata share of certain defined overhead expenses. Certain retail tenants pay additional rent based on a percentage of the tenant's sales. Expenses recovered from tenants are recorded as revenue. The escalation of lease rates included in long-term leases is recorded in earnings using the straight-line method over the term of the lease.

Asset-Retirement Obligations ("AROs")

AROs, including conditional AROs, are recorded as a liability at fair value, with a corresponding increase to utility capital assets or income producing properties. The Corporation recognizes AROs in the periods in which they are incurred if a reasonable estimate of a fair value can be determined.

Notes to Consolidated Financial Statements

The Corporation has AROs associated with hydroelectric generation facilities, interconnection facilities and wholesale energy supply agreements. While each of the foregoing will have legal AROs, including land and environmental remediation and/or removal of assets, the final date and cost of remediation and/or removal of the related assets cannot be reasonably determined at this time.

No significant environmental issues have been identified with respect to the Corporation's hydroelectric generation and transmission and distribution assets. These assets are reasonably expected to operate in perpetuity due to the nature of their operation. The licences, permits, interconnection facilities agreements and wholesale energy supply agreements are reasonably expected to be renewed or extended indefinitely to maintain the integrity of the assets and ensure the continued provision of service to customers. In the event that environmental issues are identified, assets are decommissioned or the applicable licences, permits or agreements are terminated, AROs will be recorded at that time provided the costs can be reasonably estimated.

The Corporation also has AROs associated with the removal of certain electricity distribution system assets from rights of way at the end of the life of the system. As it is expected that the system will be in service indefinitely, an estimate of the fair value of asset removal costs cannot be reasonably determined at this time.

The Corporation has determined that AROs may exist regarding the remediation of certain land. Certain leased land contains assets integral to operations and it is reasonably expected that the land-lease agreement will be renewed indefinitely; therefore, an estimate of fair value of remediation costs cannot be reasonably determined at this time. Certain other land may require environmental remediation but the amount and nature of the remediation is indeterminable at this time. AROs associated with land remediation will be recorded when the timing, nature and amount of costs can be reasonably estimated.

Capital Disclosures

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 1535, *Capital Disclosures*, which requires the Corporation to disclose additional information about its capital and the manner in which it is managed. The additional disclosure includes quantitative and qualitative information regarding the Corporation's objectives, policies and processes for managing capital. The new disclosures are provided in Note 24.

Use of Accounting Estimates

The preparation of financial statements in accordance with Canadian GAAP requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Estimates and judgments are based on historical experience, current conditions and various other assumptions believed to be reasonable under the circumstances. Additionally, certain estimates are necessary since the regulatory environments in which the Corporation's utilities operate often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. Due to changes in facts and circumstances and the inherent uncertainty involved in making estimates, actual results may differ significantly from current estimates. Estimates and judgments are reviewed periodically and, as adjustments become necessary, are reported in earnings in the period in which they become known.

3. Future Accounting Changes

International Financial Reporting Standards ("IFRS")

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that the use of IFRS will be required in 2011 for publicly accountable enterprises in Canada. In April 2008, the AcSB issued an Omnibus Exposure Draft proposing that publicly accountable enterprises be required to apply IFRS, in full and without modification, on January 1, 2011. The adoption date of January 1, 2011 will require the restatement, for comparative purposes, of amounts reported by the Corporation for its year ended December 31, 2010 and of the opening balance sheet as at January 1, 2010. The AcSB proposes that CICA Handbook Section – *Accounting Changes*, paragraph 1506.30, which would require an entity to disclose information relating to a new primary source of GAAP that has been issued but is not yet effective and that the entity has not applied, not be applied with respect to this Exposure Draft. Fortis is continuing to assess the financial reporting impacts of the adoption of IFRS and, at this time, the impact on future financial position and results of operations is not reasonably determinable or estimable. Fortis does anticipate a significant increase in disclosure resulting from the adoption of IFRS and is continuing to assess the level of disclosure required, as well as system changes that may be necessary to gather and process the information.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

3. Future Accounting Changes (cont'd)

Rate-Regulated Operations

Effective January 1, 2009, the AcSB amended: (i) CICA Handbook Section 1100, *Generally Accepted Accounting Principles* removing the temporary exemption providing relief to entities subject to rate regulation from the requirement to apply the Section to the recognition and measurement of assets and liabilities arising from rate regulation; and (ii) Section 3465, *Income Taxes* to require the recognition of future income tax liabilities and assets as well as offsetting regulatory assets and liabilities by entities subject to rate regulation.

Effective January 1, 2009, the impact on Fortis of the amendment to Section 3465, *Income Taxes* will be the recognition of future income tax assets and liabilities and related regulatory liabilities and assets for the amount of future income taxes expected to be refunded to, or recovered from, customers in future gas and electricity rates. Currently, the Terasen Gas companies, FortisAlberta, FortisBC and Newfoundland Power use the cash taxes payable method of accounting for income taxes. The effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3465, *Income Taxes* as at December 31, 2008, would have been an increase in future income tax assets and future income tax liabilities of \$24 million and \$497 million, respectively, and a corresponding increase in regulatory liabilities and regulatory assets of \$24 million and \$497 million, respectively. Included in the amounts are the future income tax effects of the subsequent settlement of the related regulatory assets and liabilities through customer rates and the separate disclosure of future income tax assets and liabilities that are currently not recognized.

Effective January 1, 2009, with the removal of the temporary exemption from Section 1100, the Corporation must now apply Section 1100 for the recognition of assets and liabilities arising from rate regulation. Certain assets and liabilities arising from rate regulation continue to have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. All assets and liabilities arising from rate regulation described in Note 4 do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100 directs the Corporation to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts*. The Corporation's regulatory assets and liabilities qualify for recognition as assets and liabilities under Section 1000. Therefore, there would be no effect on the Corporation's consolidated financial statements if it had adopted the removal of the temporary exemption from Section 1100 for the year ended December 31, 2008. Fortis is continuing to assess any additional implications on its financial reporting related to accounting for rate-regulated operations.

Goodwill and Intangible Assets

Effective January 1, 2009, the Corporation will adopt the new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. This Section, which replaces Section 3062, *Goodwill and Other Intangible Assets*, and Section 3450, *Research and Development Costs*, establishes standards for the recognition, measurement and disclosure of goodwill and intangible assets. The currently estimated effect on the Corporation's consolidated financial statements, if it had adopted amended Section 3064 as at December 31, 2008, would have been an increase in intangible assets of \$234 million, a reduction in utility capital assets of \$232 million and a reduction in deferred charges and other assets of \$2 million for the reclassification of the net book value of land and transmission rights, computer software costs and franchise costs. The Corporation is continuing to assess and quantify any additional financial reporting impacts from adopting this standard.

Credit Risk and the Fair Value of Financial Assets and Financial Liabilities

Effective January 1, 2009, the Corporation will adopt the new Emerging Issues Committee ("EIC")-173, *Credit Risk and the Fair Value of Financial Assets and Financial Liabilities*, which was issued on January 20, 2009. EIC-173 requires that the Corporation's own credit risk and the credit risk of its counterparties be taken into account in determining the fair value of a financial instrument. As at December 31, 2008, only the Corporation's derivative financial instruments were recorded at fair value (Note 25), the majority of which were out-of-the-money and recorded as a liability. The Corporation is continuing to assess any additional financial reporting impacts of adopting this EIC.

Notes to Consolidated Financial Statements

4. Regulatory Assets and Liabilities

Regulatory assets and liabilities arise as a result of the rate-setting process at the Corporation's regulated utilities. Regulatory assets represent future revenues associated with certain costs incurred that will be or are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that will be or are expected to be refunded to customers through the rate-setting process.

All amounts deferred as regulatory assets and liabilities are subject to regulatory approval. As such, the regulatory authorities could alter the amounts subject to deferral, at which time the change would be reflected in the financial statements. Certain remaining recovery and settlement periods are those expected by management and the actual recovery or settlement periods could differ based on regulatory approval.

Based on previous, existing or expected future regulatory orders or decisions, the Corporation's regulated utilities have recorded the following amounts expected to be recovered from, or refunded to, customers in future periods.

Regulatory Assets			Remaining recovery period (Years)
<i>(in millions)</i>	2008	2007	
Rate stabilization accounts – Terasen Gas companies (i)	\$ 76	\$ 99	1–3
Rate stabilization accounts – electric utilities (ii)	78	66	Various
AESO charges deferral (iii)	64	8	2
Regulatory OPEB plan asset (iv)	51	44	Indeterminable
Income taxes recoverable on OPEB plans (v)	18	16	Indeterminable
Deferred capital asset amortization (vi)	8	12	1–2
Residential unbundling (vii)	7	9	1–3
Deferred pension costs (viii)	7	8	7
Southern Crossing Pipeline tax reassessment (ix)	7	7	Indeterminable
Energy management costs (x)	7	6	1–8
Other regulatory assets (xi)	37	37	Indeterminable
Total regulatory assets	360	312	
Less: current portion	(157)	(119)	1
Long-term regulatory assets	\$ 203	\$ 193	

Regulatory Liabilities			Remaining settlement period (Years)
<i>(in millions)</i>	2008	2007	
Future asset removal and site restoration provision (xii)	\$ 337	\$ 319	Indeterminable
Rate stabilization accounts – Terasen Gas companies (i)	32	–	1–3
Rate stabilization accounts – electric utilities (ii)	9	–	1
Unbilled revenue liability (xiii)	15	22	Indeterminable
PBR incentive liabilities (xiv)	13	14	1
Southern Crossing Pipeline deferral (xv)	9	5	1–5
Fair value of the foreign exchange forward contract (xvi)	7	–	Indeterminable
Pension deferral (xvii)	4	6	1–5
Other regulatory liabilities (xviii)	20	26	Indeterminable
Total regulatory liabilities	446	392	
Less: current portion	(45)	(20)	1
Long-term regulatory liabilities	\$ 401	\$ 372	

Description of the Nature of Regulatory Assets and Liabilities

(i) Rate Stabilization Accounts – Terasen Gas Companies

The rate stabilization accounts at the Terasen Gas companies are amortized and recovered through customer rates as approved by the BCUC. The rate stabilization accounts mitigate the effect on earnings of unpredictable and uncontrollable factors, namely volume volatility caused principally by weather and natural gas cost volatility.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

4. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

At TGI, a Revenue Stabilization Adjustment Mechanism ("RSAM") accumulates the margin impact of variations in the actual-versus-forecast gas volumes consumed by residential and commercial customers. Additionally, a Commodity Cost Reconciliation Account ("CCRA") and a Midstream Cost Reconciliation Account ("MCRA") accumulate differences between actual natural gas costs and forecast natural gas costs as recovered in base rates. The CCRA also accumulates the changes in fair value of TGI's natural gas commodity swaps.

At TGVI, a Gas Cost Variance Account ("GCVA") is used to mitigate the effect on TGVI's earnings of natural gas cost volatility. The GCVA also accumulates the changes in the fair value of TGVI's natural gas commodity swaps. TGVI also maintains a Revenue Deficiency Deferral Account ("RDDA") to accumulate unrecovered costs of providing service to customers or to draw down such costs where earnings exceed the allowed ROE as set by the BCUC. During 2008 and 2007, the RDDA has decreased as achieved earnings have exceeded the allowed ROE.

The RSAM is anticipated to be refunded through rates over a three-year period, with a total balance outstanding as at December 31, 2008 of \$8 million. The MCRA, CCRA and GCVA accounts are anticipated to be fully recovered, or refunded, within the next fiscal year. In the absence of rate regulation, the amounts in the rate stabilization accounts would not be deferred but would be recorded in earnings as incurred. The recovery or refund of amounts in the rate stabilization accounts is dependent on actual natural gas consumption volumes and on annually approved customer rates.

As at December 31, 2008, the balances in the RSAM and MCRA were in a payable position, as compared to a receivable position as at December 31, 2007.

(ii) Rate Stabilization Accounts – Electric Utilities

The rate stabilization accounts associated with the Corporation's regulated electric utilities (Newfoundland Power, Maritime Electric, Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos) are recovered, or refunded, through customer rates as approved by the respective regulatory authorities. The rate stabilization accounts primarily mitigate the effect on earnings of the variability in the cost of fuel and/or purchased power above or below a forecast or predetermined level. Additionally, at Newfoundland Power the PUB has ordered the provision of a weather normalization account to adjust for the effect of variations in weather conditions when compared to long-term averages. This reduces Newfoundland Power's year-to-year earnings volatility that would otherwise result from such fluctuations in revenue and purchased power. The recovery period of the rate stabilization accounts, with the exception of Newfoundland Power's weather normalization account, whose recovery period is not determinable, ranges from one year to five years and is subject to periodic review by the respective regulators.

As at December 31, 2008, the balance in Belize Electricity's rate stabilization account was in a payable position, as compared to a receivable position as at December 31, 2007. During the second quarter of 2008, a downward \$18 million adjustment was made to Belize Electricity's cost of power rate stabilization account reflecting, in substance, the disallowance of previously incurred fuel and purchased power costs as a result of the Final Decision by the PUC on Belize Electricity's 2008/2009 rate application.

The balance in Newfoundland Power's weather normalization account should approach zero over time because it is based on long-term averages for weather conditions. As ordered by the PUB, approximately \$7 million of the weather normalization account is to be amortized equally over 2008 through 2012. In the absence of rate regulation, the fluctuations in revenue and purchased power would be recorded in earnings in the period in which they occurred. The recovery period of the remaining balance of the weather normalization account is not determinable as it depends on weather conditions in the future.

As at December 31, 2008, \$12 million in pre-2004 costs deferred in the Energy Cost Adjustment Mechanism ("ECAM") account at Maritime Electric remained to be amortized. As approved by IRAC, the remaining amount is to be amortized and collected from customers at a rate of \$2 million per year over a recovery period of six years. Annual deferral of energy costs to the ECAM account is recovered from, or refunded to, customers, as approved by IRAC, over a rolling eight-month period.

In the absence of rate regulation, the cost of fuel and/or purchased power would be expensed as incurred.

(iii) AESO Charges Deferral

FortisAlberta maintains an AESO charges deferral account that represents expenses incurred in excess of revenues collected for various items, such as transmission costs incurred and billed through to customers, that are subject to deferral to be collected in future customer rates. As at December 31, 2008, the balance of the AESO charges deferral account, comprised of the 2008 AESO charges deferral balance of \$57 million and the unsold portion of the 2007 AESO charges deferral balance, is expected to be collected in customer rates in 2010 and 2009, respectively. In the absence of rate regulation, the costs would be expensed as incurred and no deferral treatment would be permitted.

Notes to Consolidated Financial Statements

During 2007, FortisAlberta sold approximately \$28 million and \$38 million of the 2006 and 2007 AESO charges deferral accounts, respectively, to a Canadian chartered bank for proceeds of approximately \$28 million and \$38 million, respectively. Proceeds included cash consideration of \$64 million and receivables of approximately \$2 million due in February 2009 and 2010.

(iv) *Regulatory OPEB Plan Asset*

At FortisAlberta and Newfoundland Power, and prior to 2005 at FortisBC, the cash cost of providing OPEB plans is being collected in customer rates as permitted by the respective regulators. Effective 2005, as permitted by the BCUC, the recovery from customers of the cost of OPEB plans at FortisBC is based on cash costs plus a partial recovery of the full accrual cost of OPEB plans. The regulatory OPEB asset represents the deferred portion of the benefit expense at FortisAlberta, FortisBC and Newfoundland Power that is expected to be recovered from customers in future rates. In the absence of rate regulation, the benefit expense would be recognized on an accrual basis as actuarially determined with no deferral of costs recorded on the balance sheet. FortisAlberta's and FortisBC's regulatory OPEB assets are not subject to a regulatory return.

(v) *Income Taxes Recoverable on OPEB Plans*

At TGI, the regulator allows OPEB plan costs to be collected in customer gas rates on an accrual basis, rather than on a cash basis, which creates timing differences for income tax purposes. Since TGI accounts for income taxes using the cash taxes payable method, the tax effect of this timing difference is deferred as a regulatory asset and will be reduced as cash payments for OPEB plans exceed required accruals and amounts collected in customer gas rates. In the absence of rate regulation, the income tax would not be deferred.

(vi) *Deferred Capital Asset Amortization*

Newfoundland Power deferred the recovery of a \$6 million increase in capital asset amortization in each of 2006 and 2007, in accordance with a PUB order. The approximate \$12 million balance at December 31, 2007 is being amortized as an increase in amortization costs and included in customer rates equally over 2008 through 2010. In the absence of rate regulation, the deferral of the capital asset amortization would not have been recorded.

(vii) *Residential Unbundling*

Residential unbundling costs are related to costs incurred by TGI to develop a third-party marketer alternative for residential customers to purchase natural gas from suppliers other than TGI. The BCUC approved the deferral of these costs and the recovery of these costs over a three-year period. In the absence of rate regulation, these costs would have been expensed in the period incurred.

(viii) *Deferred Pension Costs*

Deferred pension costs are incremental pension costs arising from Newfoundland Power's 2005 Early Retirement Program that were deferred and are being amortized over a ten-year period that began on April 1, 2005, as ordered by the PUB. In the absence of rate regulation, these costs would have been expensed in 2005.

(ix) *Southern Crossing Pipeline Tax Reassessment*

The Southern Crossing Pipeline tax-reassessment deferral relates to an assessment of additional British Columbia Social Services Tax, for which TGI has filed an appeal. In 2006, the Company made a payment of \$10 million pending resolution of the appeal as a good faith payment. During 2007, the assessment was reduced to \$7 million and the overpayment was refunded to TGI. Depending on the success of the appeal, TGI will either be refunded the balance or, alternatively, expects to recover the costs from customers in future rates. In the absence of rate regulation, the payment would continue to be recorded as a receivable pending resolution of the appeal. Any final assessed tax, upon resolution of the appeal, would be expensed in the period in which it becomes known (Note 28).

(x) *Energy Management Costs*

FortisBC provides energy management services to promote energy efficiency programs to its customers. As required by a BCUC order, the Company has capitalized related expenditures and is amortizing these expenditures on a straight-line basis over eight years. This regulatory asset represents the unamortized balance of the energy management costs. In the absence of rate regulation, the costs of the energy management services would have been expensed in the period incurred.

(xi) *Other Regulatory Assets*

Other regulatory assets primarily relate to the Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, FortisOntario, Maritime Electric and Caribbean Utilities. The balance is comprised of various items each individually less than \$5 million. As at December 31, 2008, \$32 million of the balance was approved for recovery from customers in future rates, with the remaining balance expected to be approved. As at December 31, 2008, \$7 million (December 31, 2007 – \$9 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

4. Regulatory Assets and Liabilities (cont'd)

Description of the Nature of Regulatory Assets and Liabilities (cont'd)

(xii) Future Asset Removal and Site Restoration Provision

As required by the respective regulators, this regulatory liability represents amounts collected in customer electricity rates over the life of certain utility capital assets at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric attributable to asset removal and site restoration costs that are expected to be incurred in the future. As required by the respective regulators, amortization rates at FortisAlberta, FortisBC, Newfoundland Power and Maritime Electric include an amount allowed for regulatory purposes to provide for these future asset removal and site restoration costs, net of salvage proceeds. Actual asset removal and site restoration costs, net of salvage proceeds, are recorded against the regulatory liability when incurred.

The regulatory liability represents the amount of expected future asset removal and site restoration costs associated with utility capital assets in service as at the balance sheet date, calculated using current amortization rates as approved by the respective regulators. Any difference between actual costs incurred and those assumed in the collected amounts, and any cumulative adjustments resulting from changes to the regulator-approved amortization rates at which these costs are collected, are reflected in the regulatory liability with the offset recorded as an adjustment to accumulated amortization.

During 2008, the amount included in amortization expense associated with the provision for future asset removal and site restoration costs was \$35 million (2007 – \$33 million). During 2008, actual asset removal and site restoration costs, net of salvage proceeds, were \$21 million (2007 – \$19 million). In the absence of rate regulation, asset removal and site restoration costs, net of salvage proceeds, would have been recognized in earnings as incurred rather than provided for over the life of the assets through amortization expense.

(xiii) Unbilled Revenue Liability

Belize Electricity and, prior to 2006, Newfoundland Power record revenue derived from electricity sales on a billed basis (Note 2). The difference between revenue recognized on a billed basis and revenue recognized on an accrual basis is recorded on the balance sheet as a regulatory liability. Effective January 1, 2006, Newfoundland Power prospectively changed its revenue recognition policy to an accrual basis, as approved by the PUB. As a result, the \$24 million cumulative difference between billed revenue as of December 31, 2005 and revenue that would have been recognized on the accrual basis was recorded as a regulatory liability. As ordered by the PUB, Newfoundland Power amortized \$7 million of this regulatory liability in 2008 (2007 – \$3 million). The remaining balance as at December 31, 2008 will be amortized by approximately \$5 million in each of 2009 and 2010. In the absence of rate regulation, revenue would be recorded on an accrual basis and the deferral of unbilled revenue would not have been permitted. Belize Electricity's unbilled revenue liability of \$6 million as at December 31, 2008 (December 31, 2007 – \$5 million) is not subject to a regulatory return.

(xiv) PBR Incentive Liabilities

TGI and FortisBC's regulatory frameworks include PBR mechanisms that allow for the recovery from, or refund to, customers of a portion of certain increased or decreased costs, as compared to the forecast costs used to set customer rates. The final disposition of amounts deferred as regulatory PBR incentive assets and liabilities is determined by the sharing mechanisms with customers as approved per BCUC orders (Note 2). TGI's regulatory PBR incentive liability of \$11 million is expected to be refunded to customers through reduced rates in 2009. Based on the current PBR framework, FortisBC's 2008 regulatory PBR incentive liability of \$2 million has been approved by the BCUC for settlement in 2009 through a reduction in 2009 electricity revenue. In the absence of rate regulation, the regulatory PBR incentive amounts would not be recorded.

(xv) Southern Crossing Pipeline Deferral

This regulatory liability represents the difference between actual revenue received from third parties for the use of the Southern Crossing Pipeline and what has been approved in revenue requirements. The balance is amortized over five years. In the absence of rate regulation, the revenue would be recognized when services are rendered.

(xvi) Fair Value of the Foreign Exchange Forward Contract

This regulatory liability captures the change in the fair value of the foreign exchange forward contract, which hedges the US dollar payments required under the LNG construction contract. In the absence of rate regulation, the change in fair value of the foreign exchange forward contract would be recorded in earnings. This regulatory deferral is not subject to a regulatory return.

(xvii) Pension Deferral

This regulatory liability represents pension surplus at FortisAlberta that has not been reflected in customer rates and will result in a reduction in future customer rates when recognized. When future customer rates are reduced, this liability will be drawn down and reflected as a reduction of pension expense. In the absence of rate regulation, the pension deferral would not be permitted and the amortization of the liability would not have occurred. This regulatory pension deferral is not subject to a regulatory return.

Notes to Consolidated Financial Statements

(xviii) Other Regulatory Liabilities

Other regulatory liabilities primarily relate to the Terasen Gas companies, FortisAlberta, Newfoundland Power and FortisOntario. The balance is comprised of various items each individually less than \$5 million. As at December 31, 2008, \$17 million of the balance was approved for refund to customers or reduction in future rates, with the remaining balance expected to be approved. As at December 31, 2008, \$2 million (December 31, 2007 – \$7 million) of the balance was not subject to a regulatory return. In the absence of rate regulation, the deferrals would not be permitted.

Financial Statement Effect of Rate Regulation

In the absence of rate regulation and, therefore, in the absence of recording regulatory assets and liabilities as described above, the total impact on the consolidated financial statements would have been as follows:

(in millions)	2008	2007
Decrease in regulatory assets	\$ (349)	\$ (303)
Decrease in regulatory liabilities	(446)	(392)
Decrease in accumulated other comprehensive loss	(18)	(48)
Decrease in opening retained earnings	(61)	(60)
Increase in revenue	\$ 582	\$ 343
Increase in energy supply costs	540	340
Increase in operating expense	79	62
Decrease in amortization expense	(39)	(28)
Increase in finance charges	–	3
Decrease in corporate taxes	(16)	(15)
Net increase (decrease) in earnings	\$ 18	\$ (19)

5. Inventories

(in millions)	2008	2007
Gas in storage	\$ 212	\$ 195
Materials and supplies	17	12
	\$ 229	\$ 207

During 2008, inventories of \$1,268 million (2007 – \$559 million) were expensed and reported in energy supply costs in the consolidated statement of earnings. Inventories expensed to operating expenses were \$14 million for 2008 (2007 – \$13 million), which included \$9 million for food and beverage costs at Fortis Properties (2007 – \$8 million).

Effective January 1, 2008, the Corporation adopted CICA Handbook Section 3031, *Inventories* and inventories of \$26 million were reclassified to utility capital assets from inventories on the balance sheet, as they were held for the development, construction and maintenance of other utility capital assets (January 1, 2007 – \$18 million).

6. Deferred Charges and Other Assets

(in millions)	2008	2007
Deferred pension costs (Note 20)	\$ 128	\$ 114
Exploits Partnership hydroelectric generating facility capital assets (Note 28)	61	–
AESO contributions	48	19
Long-term accounts receivable (due 2040)	9	7
Deferred recoverable and project costs	8	7
Energy management loans	6	6
Corporate income tax deposit at Maritime Electric (Note 28)	6	6
Other deferred charges and assets	13	20
	\$ 279	\$ 179

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

6. Deferred Charges and Other Assets (cont'd)

As at December 31, 2008, the Exploits Partnership hydroelectric generating facility capital assets and deferred financing costs were reclassified to deferred charges and other assets from utility capital assets and long-term debt, respectively, as further discussed in Note 28.

AESO contributions represent payments to AESO by FortisAlberta for investment in transmission facilities that are needed for reliability or contingency planning in accordance with AESO Terms and Conditions of Service. These assets are recovered in customer rates through an AUC-approved amortization rate of approximately 3.8 per cent.

Deferred recoverable costs are amortized over the estimated remaining useful lives of the projects. Project costs are deferred until a capital project has been identified, at which time the costs are transferred to utility capital assets or income producing properties.

Energy management loans are loans to residential and general service customers for energy efficiency initiatives and related products, are interest bearing and range in terms from one year to ten years.

Other deferred charges and assets are recorded at cost and are recovered or amortized over the estimated period of future benefit.

7. Utility Capital Assets

2008					
(in millions)	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	\$ 2,426	\$ (495)	\$ (180)	\$ –	\$ 1,751
Electricity	3,948	(1,042)	(490)	(87)	2,329
Transmission					
Gas	1,304	(316)	(100)	–	888
Electricity	970	(252)	(2)	–	716
Generation	971	(280)	(1)	–	690
Assets under construction	317	–	(11)	–	306
Other	1,090	(390)	(13)	–	687
	\$ 11,026	\$ (2,775)	\$ (797)	\$ (87)	\$ 7,367
2007					
(in millions)	Cost	Accumulated Amortization	Contributions in Aid of Construction (Net)	Regulatory Tax Basis Adjustment (Net)	Net Book Value
Distribution					
Gas	\$ 2,233	\$ (364)	\$ (174)	\$ –	\$ 1,695
Electricity	3,542	(961)	(463)	(91)	2,027
Transmission					
Gas	1,277	(286)	(102)	–	889
Electricity	873	(224)	–	–	649
Generation	914	(240)	–	–	674
Assets under construction	195	–	–	–	195
Other	970	(337)	(14)	–	619
	\$ 10,004	\$ (2,412)	\$ (753)	\$ (91)	\$ 6,748

Gas distribution assets are those used to transport natural gas at low pressures (generally below 2,070 kPa). These assets include distribution stations, telemetry, distribution pipe for mains and services, meter sets and other related equipment. Electricity distribution assets are those used to distribute electricity at lower voltages (generally below 69 kV). These assets include poles, towers and fixtures, low-voltage wires, transformers, overhead and underground conductors, street lighting, meters, metering equipment and other related equipment.

Gas transmission assets are those used to transport natural gas at higher pressures (generally at 2,070 kPa and higher). These assets include transmission stations, telemetry, transmission pipe and other related equipment. Electricity transmission assets are those used to transmit electricity at higher voltages (generally at 69 kV and higher). These assets include poles, wires and conductors, substations, support structures and other related equipment.

Notes to Consolidated Financial Statements

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

Other assets include buildings, equipment, vehicles, inventory and information technology assets.

The cost of utility capital assets under capital lease as at December 31, 2008 was \$56 million (December 31, 2007 – \$51 million) and related accumulated amortization was \$24 million (December 31, 2007 – \$19 million).

8. Income Producing Properties

2008

<i>(in millions)</i>	Cost	Accumulated Amortization	Net Book Value
Buildings	\$ 485	\$ (51)	\$ 434
Land	61	–	61
Tenant inducements	24	(14)	10
Equipment	56	(23)	33
Construction in progress	3	–	3
	\$ 629	\$ (88)	\$ 541

2007

<i>(in millions)</i>	Cost	Accumulated Amortization	Net Book Value
Buildings	\$ 469	\$ (42)	\$ 427
Land	54	–	54
Tenant inducements	22	(13)	9
Equipment	46	(18)	28
Construction in progress	1	–	1
	\$ 592	\$ (73)	\$ 519

The cost of income producing property assets under capital lease as at December 31, 2008 was \$1 million (December 31, 2007 – \$6 million) and related accumulated amortization was \$0.1 million (December 31, 2007 – \$4 million).

9. Goodwill

<i>(in millions)</i>	2008	2007
Balance, beginning of year	\$ 1,544	\$ 661
Acquisition of Terasen (Note 21)	(4)	907
Reversal of restructuring accrual	–	(2)
Step-acquisition of Caribbean Utilities	6	–
Foreign currency translation impacts	29	(22)
Balance, end of year	\$ 1,575	\$ 1,544

During 2008, the Terasen Gas companies recognized the benefit of tax losses, which related to periods prior to the Corporation's ownership of Terasen resulting in a reduction in goodwill.

Goodwill associated with the acquisitions of Caribbean Utilities and Fortis Turks and Caicos is denominated in US dollars as the reporting currency of these companies is the US dollar. Foreign currency translation impacts are the result of the translation of US dollar-denominated goodwill and the impact of the movement of the Canadian dollar relative to the US dollar.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

10. Long-Term Debt and Capital Lease Obligations

(in millions)	Maturity Date	2008	2007
Regulated Utilities			
<i>Terasen Gas Companies</i>			
Secured Purchase Money Mortgages –			
10.71% weighted average fixed rate (2007 – 10.71%)	2015–2016	\$ 275	\$ 275
Unsecured Debentures –			
6.29% weighted average fixed rate (2007 – 6.44%)	2009–2038	1,380	1,068
Government loan (Note 27)	2009	8	6
Obligations under capital leases	2012	10	9
<i>FortisAlberta</i>			
Senior Unsecured Debentures –			
5.61% weighted average fixed rate (2007 – 5.57%)	2014–2047	709	610
<i>FortisBC</i>			
Secured Debentures –			
9.28% weighted average fixed rate (2007 – 9.31%)	2009–2023	44	45
Unsecured Debentures –			
6.06% weighted average fixed rate (2007 – 6.06%)	2009–2047	445	445
Obligation under capital lease	2032	26	26
<i>Newfoundland Power</i>			
Secured First Mortgage Sinking Fund Bonds –			
7.84% weighted average fixed rate (2007 – 7.84%)	2014–2037	409	414
<i>Maritime Electric</i>			
Secured First Mortgage Bonds –			
8.10% weighted average fixed rate (2007 – 9.43%)	2010–2038	152	92
<i>FortisOntario</i>			
Senior Unsecured Notes – 7.09% fixed rate	2018	52	52
<i>Belize Electricity</i>			
<i>Secured:</i>			
US RBTT Merchant Bank loan – 5.75% to 8.15% fixed rate	2010–2012	5	6
<i>Unsecured:</i>			
BZ Debentures –			
10.35% weighted average fixed rate (2007 – 10.36%)	2012–2027	42	33
Other loans – 5.81% weighted average fixed rate (2007 – 5.73%)	2009–2015	11	11
Other variable interest rate loans	2010–2015	18	10
<i>Caribbean Utilities</i>			
Unsecured Senior Loan Notes –			
6.04% weighted average fixed rate (2007 – 6.09%)	2009–2022	204	177
<i>Fortis Turks and Caicos</i>			
<i>Unsecured:</i>			
US Scotiabank (Turks and Caicos) Ltd. loan –			
3.91% weighted average fixed and variable rate (2007 – 3.88%)	2013–2016	14	13
US First Caribbean International Bank loan – 5.65% fixed rate	2015	4	3
Non-Regulated – Fortis Generation			
<i>Secured:</i>			
Mortgage – 9.44% fixed rate	2013	5	5
Term loan – 7.55% fixed rate (non-recourse to Fortis Inc.) (Note 28)	2028	61	62

Notes to Consolidated Financial Statements

(in millions)	Maturity Date	2008	2007
Non-Regulated – Fortis Properties			
<i>Secured:</i>			
First mortgages –			
7.02% weighted average fixed rate (2007 – 7.02%)	2010–2017	\$ 212	\$ 220
Senior notes – 7.32% fixed rate	2019	16	17
<i>Unsecured:</i>			
Obligation under capital lease	2008	–	2
Non-revolving variable interest rate credit facilities	2009–2010	7	7
Corporate – Fortis and Terasen			
<i>Unsecured:</i>			
Debentures –			
6.36% weighted average fixed rate (2007 – 6.33%)	2010–2014	230	436
US Senior Notes –			
6.23% weighted average fixed rate (2007 – 6.23%)	2014–2037	426	347
US Subordinated Convertible Debentures –			
5.50% weighted average fixed rate (2007 – 5.66%)	2016	44	45
Capital Securities – 8.00% fixed rate	2040	125	126
Long-term classification of credit-facility borrowings (Note 26)		224	530
Total long-term debt and capital lease obligations		5,158	5,092
Less: Deferred financing costs		(34)	(33)
Less: Current installments of long-term debt and capital lease obligations		(240)	(436)
		\$ 4,884	\$ 4,623

Certain of the long-term debt instruments held by the Corporation and its subsidiaries are secured as identified in the table above. When security is provided, it is typically a fixed or floating charge on the specific assets of the company to which the long-term debt is associated.

The purchase money mortgages of the Terasen Gas companies are secured equally and rateably by a first fixed and specific mortgage and charge on TGI's coastal division assets. The aggregate principal amount of the purchase money mortgages that may be used is limited to \$425 million.

Repayment of Long-Term Debt and Capital Lease Obligations

The consolidated annual requirements to meet principal repayments and maturities in each of the next five years and thereafter are as follows:

Year	\$ millions
2009	240
2010	219
2011	104
2012	254
2013	85
Thereafter	4,256

Regulated Utilities

FortisBC has a capital lease obligation with respect to the operation of the Brilliant Terminal Station. Future minimum lease payments associated with this capital lease obligation are approximately \$3 million per year over the remaining term of the lease agreement to 2032. The capital lease obligation bears interest at a composite rate of 8.62 per cent.

Belize Electricity's unsecured debentures can be called by the Company at any time after certain dates until maturity by giving holders not more than 60 days' nor less than 30 days' written notice, and are repayable at the option of the holders at any time on or after certain dates by giving 12 months' written notice to Belize Electricity. Redemption by agreement between Belize Electricity and the debenture holders at any time is also allowed.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

10. Long-Term Debt and Capital Lease Obligations (cont'd)

Corporate – Fortis and Terasen

Of the unsecured debentures, \$100 million are redeemable at the option of Fortis at a price calculated as the greater of the principal amount to be redeemed and an amount equal to the net present value of interest and principal based on the Government of Canada Yield, plus a premium ranging from 0.43% to 0.87%, together with accrued and unpaid interest.

The unsecured subordinated convertible debentures, due 2016, are redeemable by Fortis at par at any time on or after November 7, 2011 and are convertible, at the option of the holder, into the Corporation's common shares at \$35.46 per share (US\$29.11 per share). The debentures are subordinated to all other indebtedness of the Corporation, other than subordinated indebtedness ranking equally to the debentures.

The unsecured subordinated convertible debentures are being accounted for in accordance with their substance and are presented in the financial statements in their component parts. The liability and equity components are classified separately on the consolidated balance sheet and are measured at their respective fair values at the time of issue. The equity portion of convertible debentures was \$6 million as at December 31, 2008 (December 31, 2007 – \$6 million).

Terasen may elect to defer payment on the 8.00% capital securities and settle such deferred payments in either cash or common shares of the Company and has the option to settle principal at maturity through the issuance of common shares of the Company. The securities are also exchangeable at the option of the holder on or after April 19, 2010 for common shares of the Company at 90 per cent of the market price, subject to the right of the Company to redeem the securities for cash at par as of the same date.

11. Deferred Credits

(in millions)	2008	2007
OPEB plan liabilities (Note 20)	\$ 129	\$ 112
Defined benefit liabilities (Note 20)	34	32
Deferred gains on the sale of natural gas transmission and distribution assets	46	50
Deferred payment	43	40
Other deferred credits	25	27
	\$ 277	\$ 261

The deferred gains on the sale of natural gas transmission and distribution assets occurred upon the sale and leaseback of pipeline assets to certain municipalities in 2001, 2002, 2004 and 2005. The pre-tax gains of \$71 million on combined cash proceeds of \$141 million are being amortized over the 17-year terms of the operating leases that commenced at the time of the sale transactions. These operating lease commitments are included in the table in Note 27.

The deferred payment resulted from Terasen's acquisition of TGVI, effective January 1, 2002. The deferred payment has a face value of \$52 million but was discounted at May 17, 2007 to its present value. At December 31, 2008, its present value was \$43 million (December 31, 2007 – \$40 million). The payment is due on December 31, 2011 or sooner if TGVI realizes revenue from transportation revenue contracts to serve power-generating plants that may be constructed in TGVI's service area. If any part of the deferred payment is paid prior to December 31, 2011, the difference between the payment and the carrying value of the debt will be treated as contingent consideration for the acquisition of TGVI and will be added to the cost of the purchase at that time.

Other deferred credits primarily include customer deposits, DSU and PSU liabilities and unfunded defined contribution pension liabilities.

12. Non-Controlling Interest

(in millions)	2008	2007
Caribbean Utilities	\$ 92	\$ 67
Belize Electricity	44	38
Preference shares of Newfoundland Power	7	7
Exploits Partnership	2	3
	\$ 145	\$ 115

Notes to Consolidated Financial Statements

13. Preference Shares

Authorized

- (a) an unlimited number of First Preference Shares, without nominal or par value
- (b) an unlimited number of Second Preference Shares, without nominal or par value

Issued and Outstanding		2008		2007	
	Classification	Number of Shares	Amount (in millions)	Number of Shares	Amount (in millions)
First Preference Shares, Series C	Debt	5,000,000	\$ 123	5,000,000	\$ 123
First Preference Shares, Series E	Debt	7,993,500	197	7,993,500	197
Total classified as debt		12,993,500	\$ 320	12,993,500	\$ 320
First Preference Shares, Series F	Equity	5,000,000	\$ 122	5,000,000	\$ 122
First Preference Shares, Series G	Equity	9,200,000	225	—	—
Total classified as equity		14,200,000	\$ 347	5,000,000	\$ 122

First Preference Shares Classified as Debt

As the First Preference Shares, Series C and Series E are convertible at the option of the shareholder into a variable number of common shares of the Corporation based on a market-related price of such common shares, they meet the definition of financial liabilities and, therefore, are classified as long-term liabilities with associated dividends classified as finance charges.

The First Preference Shares, Series C and Series E are entitled to receive fixed cumulative preferential cash dividends at rates of \$1.3625 and \$1.2250 per share per annum, respectively.

On or after June 1, 2010 and 2013, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series C and Series E, respectively, in whole at any time or in part from time to time, at prices ranging from \$25.75 to \$25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

On or after June 1, 2010 and 2013, the Corporation has the option to convert all, or from time to time any part, of the outstanding First Preference Shares, Series C and Series E, respectively, into fully paid and freely tradable common shares of the Corporation. The number of common shares into which each preference share may be so converted will be determined by dividing the then-applicable redemption price per first preference share, together with all accrued and unpaid dividends, by the greater of \$1.00 and 95 per cent of the then-current market price of the common shares at such time.

On or after September 1, 2013 and 2016, each First Preference Share, Series C and Series E, respectively, will be convertible at the option of the holder on the first day of September, December, March and June of each year into fully paid and freely tradable common shares of the Corporation determined by dividing \$25.00, together with all accrued and unpaid dividends, by the greater of \$1.00 and 95 per cent of the then-current market price of the common shares. If a holder of First Preference Shares, Series C and Series E elects to convert any of such shares into common shares, the Corporation can redeem such first preference shares for cash or arrange for the sale of those shares to other purchasers.

First Preference Shares Classified as Equity

In May 2008, the Corporation issued 8 million 5.25% Cumulative Redeemable Five-Year Fixed-Rate Reset First Preference Shares, Series G ("First Preference Shares, Series G") and in June 2008 issued an additional 1.2 million First Preference Shares, Series G, following the exercise in full of an over-allotment option in connection with the offering of the 8 million First Preference Shares, Series G. The 9.2 million First Preference Shares, Series G were issued at \$25.00 per share for net after-tax proceeds of \$225 million.

As the First Preference Shares, Series F and Series G are not redeemable at the option of the shareholder, they are classified as equity and the associated dividends are deducted on the consolidated statement of earnings immediately before arriving at net earnings applicable to common shares.

The First Preference Shares, Series F are entitled to receive fixed cumulative preferential cash dividends in the amount of \$1.2250 per share per annum. The First Preference Shares, Series G are entitled to receive fixed cumulative preferential cash dividends in the amount of \$1.3125 per share per annum for each year up to and including August 31, 2013. For each five-year period after this date, the holders of First Preference Shares, Series G are entitled to receive reset fixed cumulative preferential cash dividends. The reset annual dividends per share will be determined by multiplying the \$25.00 per share by the annual fixed dividend rate, which is the sum of the five-year Government of Canada Bond Yield on the applicable reset date plus 2.13%.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

13. Preference Shares (cont'd)

First Preference Shares Classified as Equity (cont'd)

On or after December 1, 2011, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series F, in whole at any time or in part from time to time, at prices ranging from \$26.00 to \$25.00 per share plus all accrued and unpaid dividends. On September 1, 2013, and on September 1 every five years thereafter, the Corporation has the option to redeem for cash the outstanding First Preference Shares, Series G, in whole at any time or in part from time to time, at a price of \$25.00 per share plus all accrued and unpaid dividends up to but excluding the date fixed for redemption.

14. Common Shares

Authorized: an unlimited number of common shares without nominal or par value.

Issued and Outstanding	2008		2007	
	Number of Shares	Amount (in millions)	Number of Shares	Amount (in millions)
Common shares	169,190,917	\$ 2,449	155,521,313	\$ 2,126

Common shares issued during the year were as follows:

	2008		2007	
	Number of Shares	Amount (in millions)	Number of Shares	Amount (in millions)
Balance, Beginning of Year	155,521,313	\$ 2,126	104,091,542	\$ 829
Public Offering	11,700,000	291	5,170,000	146
Public Offering – Conversion of Subscription Receipts	–	–	44,275,000	1,119
Conversion of Debentures	1,041,871	11	882,626	9
Consumer Share Purchase Plan	88,686	2	79,463	3
Dividend Reinvestment Plan	230,601	6	203,763	5
Employee Share Purchase Plan	272,095	7	240,578	6
Stock Option Plans	336,351	6	578,341	9
Balance, End of Year	169,190,917	\$ 2,449	155,521,313	\$ 2,126

In December 2008, Fortis issued 11.7 million common shares for \$25.65 per common share. The common share issue resulted in gross proceeds of approximately \$300 million, or approximately \$291 million net of after-tax expenses.

During 2008, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US\$11 million of the debentures into approximately 1.0 million common shares of the Corporation.

In January 2007, Fortis issued 5.17 million common shares for \$29.00 per common share. The common share issue resulted in gross proceeds of approximately \$150 million, or approximately \$146 million net of after-tax expenses.

In March 2007, to finance a significant portion of the net cash purchase price of Terasen, the Corporation sold approximately 44.3 million Subscription Receipts at \$26.00 each for gross proceeds of approximately \$1.15 billion. Upon closing of the acquisition of Terasen on May 17, 2007, each Subscription Receipt was exchanged, without payment of additional consideration, for one common share of Fortis. Each Subscription Receipt holder also received a cash payment of \$0.21 per Subscription Receipt, which was an amount equal to the dividend declared per common share of Fortis to holders of record as of May 4, 2007. The net proceeds to the Corporation upon conversion of the Subscription Receipts were approximately \$1.12 billion net of after-tax expenses.

During 2007, holders of the Corporation's former 6.75% and 5.50% unsecured subordinated convertible debentures converted approximately US\$9 million of the US\$20 million debentures into approximately 0.9 million common shares of the Corporation.

As at December 31, 2008, 9.8 million (December 31, 2007 – 6.2 million) common shares remained reserved for issuance under the terms of the above-noted share purchase, dividend reinvestment and stock option plans. During 2008, an additional 5 million common shares were reserved under the dividend reinvestment plan in accordance with an enhancement made to the plan. The Corporation amended and restated its dividend reinvestment plan to provide a 2 per cent discount on the purchase of common shares issued from treasury, with reinvested dividends, effective March 1, 2009.

As at December 31, 2008, common shares reserved for issuance under the terms of the Corporation's convertible debentures and preference shares were 1.4 million and 26 million, respectively (December 31, 2007 – 2.4 million and 26 million, respectively).

Notes to Consolidated Financial Statements

As at December 31, 2008, \$3 million (December 31, 2007 – \$3 million) of common share equity had not been fully paid relating to amounts outstanding under employee share purchase and executive stock option loans.

Earnings per Common Share

The Corporation calculates earnings per common share on the weighted average number of common shares outstanding. The weighted average number of common shares outstanding was 157.4 million for 2008 and 137.6 million for 2007.

Diluted earnings per common share are calculated using the treasury stock method for options and the “if-converted” method for convertible securities.

Earnings per common share are as follows:

	2008			2007		
	Earnings (in millions)	Weighted Average Shares (in millions)	Earnings per Common Share	Earnings (in millions)	Weighted Average Shares (in millions)	Earnings per Common Share
Basic Earnings per Common Share	\$ 245	157.4	\$ 1.56	\$ 193	137.6	\$ 1.40
Effect of Potential Dilutive Securities:						
Subscription Receipts ⁽¹⁾	–	–		–	7.8	
Stock Options	–	1.0		–	1.2	
Preference Shares (Notes 13 and 17)	17	13.9		17	11.5	
Convertible Debentures	2	1.4		3	2.8	
	264	173.7		213	160.9	
Deduct Anti-Dilutive Impacts:						
Convertible Debentures	–	–		(2)	(1.4)	
Diluted Earnings per Common Share	\$ 264	173.7	\$ 1.52	\$ 211	159.5	\$ 1.32

⁽¹⁾ Dilution relates to the period the Subscription Receipts were outstanding from March 15, 2007 to May 16, 2007, prior to their conversion into common shares.

15. Stock-Based Compensation Plans

Stock Options

The Corporation is authorized to grant officers and certain key employees of Fortis and its subsidiaries options to purchase common shares of the Corporation. As at December 31, 2008, the Corporation had the following stock option plans: 2006 Plan, 2002 Plan and Executive Stock Option Plan. The 2002 Plan was adopted at the Annual and Special General Meeting on May 15, 2002 to ultimately replace the Executive and the former Directors' Stock Option Plans. The Executive Stock Option Plan will cease to exist when all outstanding options are exercised or expire in or before 2011. The 2006 Plan was approved at the May 2, 2006 Annual Meeting at which Special Business was conducted. The 2006 Plan will ultimately replace the 2002 Plan. The 2002 Plan will cease to exist when all outstanding options are exercised or expire in or before 2016. The Corporation has ceased to grant options under the Executive Stock Option Plan and 2002 Plan and all new options are being granted under the 2006 Plan.

Options granted under the 2006 Plan have a maximum term of seven years and expire no later than three years after the termination, death or retirement of the optionee and vest evenly over a four-year period on each anniversary of the date of grant. Directors are not eligible to receive grants of options under the 2006 Plan.

Number of Options:	2008	2007
Options outstanding, beginning of year	3,691,771	3,550,055
Granted	827,504	754,800
Cancelled	(42,462)	(34,743)
Exercised	(336,351)	(578,341)
Options outstanding, end of year	4,140,462	3,691,771
Options vested, end of year	2,279,240	1,901,811

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

15. Stock-Based Compensation Plans (cont'd)

Weighted Average Exercise Prices:	2008	2007
Options outstanding, beginning of year	\$ 18.86	\$ 16.11
Granted	28.27	27.75
Cancelled	24.20	22.43
Exercised	14.48	13.35
Options outstanding, end of year	21.04	18.86

Details of stock options outstanding and vested as at December 31, 2008 are as follows:

Number of Options Outstanding	Number of Options Vested	Exercise Price	Expiry Date
97,842	97,842	\$ 9.57	2011
166,473	166,473	\$ 12.03	2012
472,393	472,393	\$ 12.81	2013
572,528	572,528	\$ 15.28	2014
10,000	10,000	\$ 15.23	2014
32,793	32,793	\$ 14.55	2014
637,902	457,808	\$ 18.40	2015
28,000	21,000	\$ 18.11	2015
17,500	9,065	\$ 20.82	2015
556,615	256,072	\$ 22.94	2016
596,232	149,058	\$ 28.19	2014
136,832	34,208	\$ 25.76	2014
815,352	—	\$ 28.27	2015
4,140,462	2,279,240		

The weighted average exercise price of stock options vested as at December 31, 2008 was \$16.81.

In February 2008, the Corporation granted 827,504 options to purchase common shares under its 2006 Plan at the five-day volume weighted average trading price of \$28.27 immediately preceding the date of grant. The fair value of each option granted was \$4.76 per option.

The fair value was estimated on the date of grant using the Black-Scholes fair value option-pricing model and the following assumptions:

Dividend yield (%)	2.90
Expected volatility (%)	20.7
Risk-free interest rate (%)	3.92
Weighted average expected life (years)	4.5

The Corporation records compensation expense upon the issuance of stock options granted under its 2002 and 2006 Plans. Using the fair value method, the compensation expense is amortized over the four-year vesting period of the options granted. Under the fair value method, compensation expense associated with stock options was \$3 million for the year ended December 31, 2008 (2007 – \$2 million).

Directors' DSU Plan

In 2004, the Corporation introduced the Directors' DSU Plan as an optional vehicle for directors to elect to receive credit for their annual retainer to a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation. The Corporation may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Effective 2006, directors who are not officers of the Corporation are eligible for grants of DSUs representing the equity portion of directors' annual compensation.

Notes to Consolidated Financial Statements

Number of DSUs:	2008	2007
DSUs outstanding, beginning of year	69,722	46,959
Granted	27,224	20,859
Granted – notional dividends reinvested	3,671	1,904
DSUs outstanding, end of year	100,617	69,722

For the year ended December 31, 2008, expense of \$0.2 million (2007 – \$0.8 million) was recorded in relation to the DSU Plan.

PSU Plan

In 2004, the Corporation introduced the PSU Plan, which is included as a component of the long-term incentives awarded only to the President and Chief Executive Officer (“CEO”) of the Corporation. Each PSU represents a unit with an underlying value equivalent to the value of one common share of the Corporation.

Number of PSUs:	2008	2007
PSUs outstanding, beginning of year	67,615	66,845
Granted	32,940	19,570
Granted – notional dividends reinvested	3,011	1,883
PSUs paid out	(18,019)	(20,683)
PSUs outstanding, end of year	85,547	67,615

In March 2008, 18,019 PSUs were paid out to the President and CEO of the Corporation at \$28.36 per PSU for a total of approximately \$0.5 million. The payout was made upon the three-year maturation period in respect of the PSU grant made in March 2005, and the President and CEO satisfying the payment requirements as determined by the Human Resources Committee of the Board of Directors of Fortis.

For the year ended December 31, 2008, expense of \$0.6 million (2007 – \$0.6 million) was recorded in relation to the PSU Plan.

16. Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss includes unrealized foreign currency translation gains and losses, net of hedging activities, gains and losses on cash flow hedging activities and gains and losses on discontinued cash flow hedging activities, as discussed in Note 2.

	2008		
<i>(in millions)</i>	Opening balance January 1	Net change	Ending balance December 31
Unrealized foreign currency translation (losses) gains, net of hedging activities and tax	\$ (82)	\$ 36	\$ (46)
Losses on derivative instruments designated as cash flow hedges, net of tax	(1)	–	(1)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	(5)	–	(5)
Accumulated other comprehensive loss	\$ (88)	\$ 36	\$ (52)

	2007			
<i>(in millions)</i>	Opening balance January 1	Transition amount January 1	Net change	Ending balance December 31
Unrealized foreign currency translation losses, net of hedging activities and tax	\$ (51)	\$ –	\$ (31)	\$ (82)
Losses on derivative instruments designated as cash flow hedges, net of tax	–	(1)	–	(1)
Net losses on derivative instruments previously discontinued as cash flow hedges, net of tax	–	(5)	–	(5)
Accumulated other comprehensive loss	\$ (51)	\$ (6)	\$ (31)	\$ (88)

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

16. Accumulated Other Comprehensive Loss (cont'd)

During 2008, unrealized foreign currency translation gains of \$115 million (2007 – losses of \$70 million) were recorded in accumulated other comprehensive loss related to the Corporation's net investment in foreign currency-denominated self-sustaining foreign operations. These unrealized foreign currency translation gains were partially offset by the effective portion of unrealized after-tax losses of \$79 million (2007 – after-tax gains of \$39 million) related to the translation of corporately held US dollar-denominated long-term debt designated as a foreign currency risk hedge. There was no ineffective portion.

As at January 1, 2007, in accordance with the transitional provisions of CICA Handbook Section 3865, *Hedges*, a net loss of \$5 million associated with unamortized deferred gain and loss balances related to previously cancelled swap agreements was reclassified to accumulated other comprehensive loss. The deferred gain and loss balances are amortized to comprehensive income on a straight-line basis over the life of the related debt.

On January 1, 2007, as required upon initial application of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*, all adjustments to the carrying amount of financial instruments were recognized as an adjustment to the opening balance of accumulated other comprehensive loss. The Corporation was not required to remeasure any assets or liabilities upon adoption of Section 3855; therefore, no adjustments were made to the opening balance of retained earnings.

17. Finance Charges

(in millions)

	2008	2007
Interest – Long-term debt and capital lease obligations	\$ 329	\$ 266
– Short-term borrowings	32	27
AFUDC (Note 2)	(13)	(8)
Interest earned	(2)	(4)
Unrealized foreign exchange loss on long-term debt	–	1
Dividends on preference shares (Notes 13 and 14)	17	17
	\$ 363	\$ 299

18. Gain on Sale of Property

In December 2007, TGI sold surplus land resulting in an \$8 million (\$7 million after-tax) gain on the sale.

Notes to Consolidated Financial Statements

19. Corporate Taxes

Corporate taxes differ from the amount that would be expected to be generated by applying the enacted combined Canadian federal and provincial statutory tax rate to earnings before corporate taxes and non-controlling interest. The following is a reconciliation of consolidated statutory taxes to consolidated effective taxes.

<i>(in millions, except as noted)</i>	2008	2007
Combined Canadian federal and provincial statutory income tax rate	33.5%	36.1%
Statutory income tax rate applied to earnings		
before corporate taxes and non-controlling interest	\$ 113	\$ 90
Preference share dividends	6	6
Difference between Canadian statutory rate and rates applicable to foreign subsidiaries	(12)	(18)
Difference in Canadian provincial statutory rates applicable		
to subsidiaries in different Canadian jurisdictions	(6)	(3)
Items capitalized for accounting but expensed for income tax purposes	(33)	(21)
Difference between capital cost allowance ("CCA") and other deductions		
claimed for income tax purposes and amounts recorded for accounting purposes ⁽¹⁾	5	(12)
Impact of reduction in income tax rates on future income taxes	–	(6)
Québec Tax Trust and other tax settlements – Terasen ⁽²⁾	(7)	2
Maritime Electric tax reassessment	–	3
Pension costs	(2)	(2)
Other	1	(3)
Corporate taxes	\$ 65	\$ 36
Effective tax rate	19.3%	14.4%

⁽¹⁾ During 2008, CCA deductions at FortisAlberta were lower than amortization expense. However, during 2007, CCA deductions at FortisAlberta were higher than amortization expense. The higher CCA deductions in 2007 were required to offset taxable income on the sale, in 2007, of the 2006 AESO charges deferral receivable balance.

⁽²⁾ During 2008, Terasen reached a settlement with Revenu Québec and Canada Revenue Agency related to amounts owing as a result of amended Québec tax legislation. The legislation was passed in 2006 for the purpose of challenging certain interprovincial Canadian tax structures. As a result of the settlement, Terasen recorded an approximate \$7.5 million tax reduction in 2008.

The components of the provision for corporate taxes are as follows:

<i>(in millions)</i>	2008	2007
Canadian		
Current taxes	\$ 47	\$ 33
Future income taxes	16	–
	63	33
Foreign		
Current taxes	4	3
Future income taxes	(2)	–
	2	3
Corporate taxes	\$ 65	\$ 36

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

19. Corporate Taxes (cont'd)

Future income taxes are provided for temporary differences. Future income tax assets and liabilities are comprised of the following:

(in millions)	2008	2007
Future income tax liability (asset)		
Income producing properties	\$ 26	\$ 22
Utility capital assets	17	13
ECAM	16	10
Other regulatory assets and liabilities	2	2
Intangible assets	3	5
Employee future benefits	(14)	(14)
Loss carryforwards	(11)	(10)
Share issue and debt financing costs	(14)	(16)
Unrealized foreign currency translation (losses) gains on long-term debt	(5)	8
Other	2	5
Net future income tax liability	\$ 22	\$ 25
Current future income tax liability	\$ 15	\$ 7
Long-term future income tax asset	(54)	(37)
Long-term future income tax liability	61	55
Net future income tax liability	\$ 22	\$ 25

As at December 31, 2008, the Corporation had approximately \$104 million (December 31, 2007 – \$51 million) in non-capital and capital loss carryforwards, of which \$8 million (December 31, 2007 – \$3 million) in capital losses has not been recognized in the financial statements. The non-capital loss carryforwards expire between 2009 and 2028.

20. Employee Future Benefits

The Corporation and its subsidiaries each maintain one or a combination of defined benefit pension plans, defined contribution pension plans and group RRSPs for its employees. The Corporation, Terasen Gas companies, FortisAlberta, FortisBC, Newfoundland Power, Maritime Electric and FortisOntario also offer OPEB plans for qualifying employees.

For the defined benefit pension arrangements, the accrued pension benefit obligation and the market-related value or fair value of plan assets are measured for accounting purposes as at December 31 of each year for the Corporation, Terasen Gas companies, Newfoundland Power and Caribbean Utilities commencing December 2008 (2007 – measured as at April 30), and as at September 30 of each year for FortisAlberta, FortisBC and FortisOntario. The most recent actuarial valuation of the pension plans for funding purposes was as of December 31, 2007 for FortisAlberta and FortisBC; as of December 31, 2006 for FortisOntario; as of December 31, 2005 for the Corporation and Newfoundland Power; and as of December 31, 2008 for Caribbean Utilities. For the Terasen Gas companies, the most recent actuarial valuations of the pension plans for funding purposes were between December 31, 2005 and December 31, 2007. The next required valuations will be, at the latest, three years from the date of the most recent actuarial valuation for each company.

Actuarial valuations of the pension plans for funding purposes are currently being completed as of December 31, 2008 for the Corporation, Newfoundland Power and one of the pension plans at the Terasen Gas companies. The valuations are expected to be completed in 2009.

The Corporation's consolidated defined benefit pension plan asset allocation is as follows:

Plan assets as at December 31

(%)	2008	2007
Canadian equities	42	50
Fixed income	44	38
Foreign equities	8	8
Real estate	6	4
	100	100

Notes to Consolidated Financial Statements

The following is a breakdown of the Corporation's and subsidiaries' defined benefit pension plans and their respective funded or unfunded status:

	2008			2007		
(in millions)	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)	Accrued Benefit Obligation	Plan Assets	Net Funded (Unfunded)
Terasen Gas companies	\$ 253	\$ 227	\$ (26)	\$ 254	\$ 261	\$ 7
FortisAlberta	22	18	(4)	23	20	(3)
FortisBC	117	96	(21)	122	105	(17)
Newfoundland Power	190	212	22	236	260	24
FortisOntario	21	19	(2)	23	21	(2)
Caribbean Utilities	6	3	(3)	5	3	(2)
Fortis Inc.	4	4	–	4	4	–
Total	\$ 613	\$ 579	\$ (34)	\$ 667	\$ 674	\$ 7

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	2008	2007	2008	2007	2008	2007
Change in accrued benefit obligation						
Balance, beginning of year	\$ 667	\$ 413	\$ 44	\$ 17	\$ 189	\$ 109
Liability associated with acquisitions	–	248	–	27	–	79
Current service costs	16	12	1	1	4	4
Employee contributions	8	6	–	–	–	–
Interest costs	36	29	2	2	10	8
Benefits paid	(32)	(25)	(2)	(2)	(4)	(4)
Actuarial gain	(80)	(16)	(4)	(1)	(30)	(8)
Plan amendments	(2)	–	–	–	–	1
Balance, end of year	\$ 613	\$ 667	\$ 41	\$ 44	\$ 169	\$ 189
Change in value of plan assets						
Balance, beginning of year	\$ 674	\$ 390	\$ –	\$ –	\$ –	\$ –
Assets associated with acquisitions	–	256	–	–	–	–
Actual (loss) return on plan assets	(92)	26	–	–	–	–
Benefits paid	(32)	(25)	(2)	(2)	(4)	(4)
Employee contributions	8	6	–	–	–	–
Employer contributions	21	21	2	2	4	4
Balance, end of year	\$ 579	\$ 674	\$ –	\$ –	\$ –	\$ –
Funded status						
(Deficit) surplus, end of year	\$ (34)	\$ 7	\$ (41)	\$ (44)	\$ (169)	\$ (189)
Unamortized net actuarial loss (gain)	152	95	(1)	3	26	61
Unamortized past service costs	7	10	1	1	(2)	(2)
Unamortized transitional obligation	7	7	2	2	15	18
Plan amendment	–	–	–	–	1	–
Employer contributions after measurement date	1	1	–	–	–	–
Accrued benefit asset (liability), end of year						
	\$ 133	\$ 120	\$ (39)	\$ (38)	\$ (129)	\$ (112)
Deferred pension costs (Note 6)	\$ 135	\$ 121	\$ (7)	\$ (7)	\$ –	\$ –
Defined benefit liabilities (Note 11)	(2)	(1)	(32)	(31)	–	–
OPEB plan liabilities (Note 11)	–	–	–	–	(129)	(112)
	\$ 133	\$ 120	\$ (39)	\$ (38)	\$ (129)	\$ (112)

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

20. Employee Future Benefits (cont'd)

	Defined Benefit Pension Plans Funded		Supplementary Defined Benefit Plans Unfunded		OPEB Plans Unfunded	
(in millions)	2008	2007	2008	2007	2008	2007
Significant assumptions						
Discount rate during the year (%)	5.25–5.60	5.00–5.25	5.25–5.75	5.00–5.25	5.25–5.75	5.00–5.25
Discount rate as at December 31 (%)	6.00–7.50	5.25–5.60	6.25–7.50	5.25–5.75	6.00–7.50	5.25–5.75
Expected long-term rate of return on plan assets (%)	3.00–7.50	6.50–7.50	–	–	–	–
Rate of compensation increase (%)	3.00–5.00	3.50–4.25	3.19–5.00	3.77–4.25	3.50–5.00	3.50–4.25
Health-care cost trend increase as at December 31 (%)	–	–	–	–	4.41–9.00	4.50–10.00
Expected average remaining service life of active employees (years)	5–12	7–13	4–12	3–13	9–15	10–16
Components of net benefit expense						
Current service costs	\$ 16	\$ 12	\$ 1	\$ 1	\$ 4	\$ 4
Interest costs	36	29	2	2	10	8
Actual loss (return) on plan assets	92	(26)	–	–	–	–
Actuarial gain	(80)	(16)	(4)	(1)	(30)	(8)
Plan amendments	(2)	–	–	–	–	1
Costs arising in the year	62	(1)	(1)	2	(16)	5
Differences between costs arising and costs recognized in the year in respect of:						
Return on plan assets	(141)	(11)	–	–	–	–
Actuarial gain	84	20	4	1	34	11
Past service costs	3	2	1	–	–	–
Special termination benefits	–	1	–	–	–	–
Transitional obligation and amendments	–	1	–	–	3	2
Regulatory adjustment	1	–	–	–	(7)	(7)
Net benefit expense	\$ 9	\$ 12	\$ 4	\$ 3	\$ 14	\$ 11

For 2008, the effects of changing the health-care cost trend rate by 1 per cent are as follows:

(in millions)	1 per cent increase in rate	1 per cent decrease in rate
Increase (decrease) in accrued benefit obligation	\$ 22	\$ (16)
Increase (decrease) in current service and interest costs	2	(2)

The following table provides the sensitivities associated with a 100 basis point move in the expected long-term rate of return on pension plan assets and the discount rate on 2008 net defined benefit pension expense, and the related accrued defined benefit pension asset and liability recorded in the Corporation's consolidated financial statements, as well as the impact on the accrued defined benefit pension obligation.

Increase (Decrease)	Net Benefit Expense	Accrued Benefit Asset	Accrued Benefit Liability	Accrued Benefit Obligation
(in millions)				
Impact of increasing the rate of return assumption by 100 basis points	\$ (7)	\$ 7	\$ –	\$ –
Impact of decreasing the rate of return assumption by 100 basis points	7	(7)	–	–
Impact of increasing the discount rate assumption by 100 basis points	(3)	2	(1)	(57)
Impact of decreasing the discount rate assumption by 100 basis points	10	(8)	1	67

During 2008, the Corporation expensed \$11 million (2007 – \$10 million) related to defined contribution pension plans.

Notes to Consolidated Financial Statements

21. Business Acquisitions

2008

Fairmont Newfoundland Hotel

In November 2008, Fortis Properties purchased the Fairmont Newfoundland hotel for an aggregate cash purchase price of approximately \$22 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing November 2008.

The purchase price allocation to assets, based on their fair values, was as follows:

<i>(in millions)</i>	Total
Fair value assigned to net assets:	
Income producing properties	\$ 22

2007

a. Terasen

On May 17, 2007, Fortis acquired all of the issued and outstanding common shares of Terasen for aggregate consideration of approximately \$3.7 billion. The net cash purchase price of approximately \$1.25 billion, including acquisition costs, was primarily financed through proceeds from the issuance of common equity, with the remaining \$125 million of the net cash purchase price being financed, on an interim basis, through drawings on the Corporation's committed credit facility.

Terasen owns and operates a gas distribution business carried on by TGI, TGV and TGWI. Terasen is the principal natural gas distributor in British Columbia.

The acquisition has been accounted for using the purchase method, whereby the consolidated results of Terasen have been included in the consolidated financial statements of Fortis commencing May 17, 2007. The financial results of the Terasen Gas companies have been included in the Regulated Gas Utilities – Canadian segment, while net expenses of non-regulated Terasen corporate-related activities, Terasen's 30 per cent investment in non-regulated CWLP and Terasen's 100 per cent investment in non-regulated TES have been included in the Corporate and Other segment. The Terasen Gas companies are regulated under traditional cost of service. The determination of revenue and earnings is based on regulated rates of return that are applied to historic values which do not change with a change of ownership. Therefore, for substantially all of the individual assets and liabilities associated with the Terasen Gas companies, no fair market value adjustments were recorded as part of the purchase price because all of the economic benefits and obligations associated with them beyond regulated rates of return accrue to the customers. Accordingly, the book value of substantially all of the assets and liabilities of the Terasen Gas companies has been assigned as fair value for the purchase price allocation. Substantially all of the fair market value adjustments, including intangibles, recorded as part of the purchase price allocation are related to non-regulated Terasen and its non-regulated investments.

The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition. The amount of the purchase price assignable to goodwill is entirely associated with the regulated Terasen Gas companies. Approximately \$40 million of goodwill is deductible for tax purposes. Of the \$11 million in intangible assets, \$10 million was assigned as the value associated with customer contracts at CWLP. Approximately \$1 million was assigned to the Terasen trade-name associated with non-regulated activities and is not subject to amortization.

During 2008, the Terasen Gas companies recognized the benefit of tax losses, which related to periods prior to the Corporation's ownership of Terasen, resulting in a \$6 million reduction in goodwill. Partially offsetting the above was a final purchase adjustment of \$2 million, which increased goodwill.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

21. Business Acquisitions (cont'd)

a. Terasen (cont'd)

<i>(in millions)</i>	Total
Fair value assigned to net assets:	
Utility capital assets	\$ 2,768
Current assets	361
Goodwill	903
Intangibles	11
Long-term regulatory assets	69
Other assets	42
Current liabilities	(355)
Assumed short-term indebtedness	(275)
Assumed long-term debt (including current portion)	(2,077)
Long-term regulatory liabilities	(29)
Other liabilities	(165)
	1,253
Cash	3
	<u>\$ 1,256</u>

b. Delta Regina

In August 2007, Fortis Properties purchased the Delta Regina, comprising the Delta Regina hotel, the Saskatchewan Trade and Convention Centre, 52,000 square feet of commercial office space and a parking garage in Regina, Saskatchewan for an aggregate cash purchase price of approximately \$50 million, including acquisition costs.

The acquisition has been accounted for using the purchase method, whereby the results of operations have been consolidated in the financial statements of Fortis commencing August 2007.

The purchase price allocation to assets, based on their fair values, was as follows:

<i>(in millions)</i>	Total
Fair value assigned to net assets:	
Income producing properties	\$ 50

Notes to Consolidated Financial Statements

22. Segmented Information

Information by reportable segment is as follows:

Year ended December 31, 2008 (\$ millions)	REGULATED							NON-REGULATED				
	Gas Utilities		Electric Utilities									
	Terasen Gas Companies – Canadian ⁽¹⁾	Fortis Alberta	Fortis BC	NF Power	Other Canadian ⁽²⁾	Total Electric Canadian	Electric Caribbean ⁽³⁾	Fortis Generation	Fortis Properties	Corporate and Other	Inter- segment eliminations	Consolidated
Revenue	1,902	300	237	517	262	1,316	408	82	207	26	(38)	3,903
Energy supply costs	1,268	–	68	337	177	582	273	7	–	–	(18)	2,112
Operating expenses	253	130	67	50	28	275	55	14	135	16	(5)	743
Amortization	97	85	34	45	18	182	36	10	15	8	–	348
Operating income	284	85	68	85	39	277	44	51	57	2	(15)	700
Finance charges	129	42	28	33	18	121	16	8	24	80	(15)	363
Corporate taxes (recoveries)	37	(3)	6	19	7	29	2	10	10	(23)	–	65
Non-controlling interest	–	–	–	1	–	1	9	3	–	–	–	13
Net earnings (loss)	118	46	34	32	14	126	17	30	23	(55)	–	259
Preference share dividends	–	–	–	–	–	–	–	–	–	14	–	14
Net earnings (loss) applicable to common shares	118	46	34	32	14	126	17	30	23	(69)	–	245
Goodwill	903	227	221	–	63	511	161	–	–	–	–	1,575
Identifiable assets	3,721	1,574	990	1,001	520	4,085	867	285	559	126	(40)	9,603
Total assets	4,624	1,801	1,211	1,001	583	4,596	1,028	285	559	126	(40)	11,178
Gross capital expenditures	220	302	117	67	46	532	110	19	14	9	–	904

Year ended
December 31, 2007
(\$ millions)

Revenue	905	270	229	491	263	1,253	307	75	191	22	(35)	2,718
Energy supply costs	559	–	67	327	174	568	169	8	–	–	(17)	1,287
Operating expenses	150	122	69	53	29	273	49	14	123	13	(5)	617
Amortization	58	75	31	34	17	157	28	10	14	6	–	273
Operating income	138	73	62	77	43	255	61	43	54	3	(13)	541
Finance charges	80	36	26	34	17	113	15	10	24	70	(13)	299
Gain on sale of property	(8)	–	–	–	–	–	–	–	–	–	–	(8)
Corporate taxes (recoveries)	16	(11)	5	12	10	16	2	8	6	(12)	–	36
Non-controlling interest	–	–	–	1	–	1	13	1	–	–	–	15
Net earnings (loss)	50	48	31	30	16	125	31	24	24	(55)	–	199
Preference share dividends	–	–	–	–	–	–	–	–	–	6	–	6
Net earnings (loss) applicable to common shares	50	48	31	30	16	125	31	24	24	(61)	–	193
Goodwill	907	227	221	–	63	511	126	–	–	–	–	1,544
Identifiable assets	3,540	1,294	914	986	484	3,678	652	235	535	108	(19)	8,729
Total assets	4,447	1,521	1,135	986	547	4,189	778	235	535	108	(19)	10,273
Gross capital expenditures	120	285	147	72	38	542	106	17	13	5	–	803

⁽¹⁾ The Terasen Gas companies were acquired on May 17, 2007.

⁽²⁾ Includes Maritime Electric and FortisOntario

⁽³⁾ Includes Belize Electricity, Caribbean Utilities and Fortis Turks and Caicos. Results for 2008 include two additional months of contribution from Caribbean Utilities due to a change in the utility's fiscal year end.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

22. Segmented Information (cont'd)

Inter-segment transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. The significant inter-segment transactions primarily related to the sale of energy from Fortis Generation to Belize Electricity and FortisOntario, electricity sales from Newfoundland Power to Fortis Properties and finance charges on inter-segment borrowings. The significant inter-segment transactions during the years ended December 31 were as follows:

(in millions)	2008	2007
Sales from Fortis Generation to Regulated Electric Utilities – Caribbean	\$ 17	\$ 15
Sales from Fortis Generation to Other Canadian Electric Utilities	1	1
Sales from Newfoundland Power to Fortis Properties	4	4
Inter-segment finance charges on borrowings from:		
Corporate to Regulated Electric Utilities – Canadian	2	2
Corporate to Regulated Electric Utilities – Caribbean	5	1
Corporate to Fortis Properties	8	8

23. Supplementary Information to Consolidated Statements of Cash Flows

(in millions)	2008	2007
Interest paid	\$ 373	\$ 288
Income taxes paid	33	53

24. Capital Management

The Corporation's principal businesses of regulated gas and electricity distribution require ongoing access to capital in order to allow the utilities to fund the maintenance and expansion of infrastructure. Fortis raises debt at the subsidiary level to ensure regulatory transparency, tax efficiency and financing flexibility. To help ensure access to capital, the Corporation targets a consolidated long-term capital structure containing approximately 40 per cent equity, including preference shares, and 60 per cent debt, as well as investment-grade credit ratings.

Each of the Corporation's regulated utilities maintains its own capital structure in line with the deemed capital structure reflected in the utilities' customer rates. Fortis generally finances a significant portion of acquisitions with proceeds from common and preference share issuances.

The consolidated capital structure of Fortis is presented in the following table.

	As at December 31, 2008		As at December 31, 2007	
	(in millions)	(%)	(in millions)	(%)
Total debt and capital lease obligations (net of cash) ⁽¹⁾	\$ 5,468	59.5	\$ 5,476	64.3
Preference shares ⁽²⁾	667	7.3	442	5.2
Common shareholders' equity	3,046	33.2	2,601	30.5
Total	\$ 9,181	100.0	\$ 8,519	100.0

⁽¹⁾ Includes long-term debt and capital lease obligations, including current portion, and short-term borrowings, net of cash

⁽²⁾ Includes preference shares classified as both long-term liabilities and equity

Certain of the Corporation's long-term debt obligations have covenants restricting the issuance of additional debt such that consolidated debt cannot exceed 70 per cent of the Corporation's consolidated capital structure, as defined by the long-term debt agreements. As at December 31, 2008, the Corporation and its subsidiaries, except for Belize Electricity and the Exploits Partnership as described below, were in compliance with their debt covenants.

As a result of the regulator's Final Decision on Belize Electricity's 2008/2009 rate application, Belize Electricity does not meet certain debt covenant financial ratios related to loans totalling \$11 million (BZ\$18 million) as at December 31, 2008. The Company has informed the lenders of the defaults and has requested appropriate waivers. Belize Electricity is also in default of certain debt covenants which has resulted in Belize Electricity being prohibited from incurring new indebtedness or declaring dividends.

As a result of legislation passed in 2008 by the Government of Newfoundland and Labrador expropriating most of the Newfoundland assets of Abitibi-Consolidated, the Exploits Partnership is potentially in default on a \$61 million term loan. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The term loan, which is non-recourse to Fortis, has been reclassified to current portion of long-term debt on the consolidated balance sheet as at December 31, 2008. See Note 28 for a further discussion of the Exploits Partnership.

The Corporation's credit ratings and consolidated credit facilities are discussed further under "Liquidity Risk" in Note 26.

Notes to Consolidated Financial Statements

25. Financial Instruments

The Corporation has designated its non-derivative financial instruments as follows:

(in millions)	December 31, 2008		December 31, 2007	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Held for trading				
Cash and cash equivalents ⁽¹⁾	\$ 66	\$ 66	\$ 58	\$ 58
Loans and receivables				
Trade and other accounts receivable ⁽¹⁾⁽²⁾⁽³⁾	674	674	630	630
Other receivables due from customers ⁽¹⁾⁽³⁾⁽⁴⁾	8	8	7	7
Other financial liabilities				
Short-term borrowings ⁽¹⁾⁽³⁾	410	410	475	475
Trade and other accounts payable ⁽¹⁾⁽³⁾⁽⁵⁾	782	782	714	714
Dividends payable ⁽¹⁾⁽³⁾	47	47	43	43
Customer deposits ⁽¹⁾⁽³⁾⁽⁶⁾	6	6	5	5
Long-term debt, including current portion ⁽⁷⁾⁽⁸⁾	5,088	4,927	5,023	5,635
Preference shares, classified as debt ⁽⁷⁾⁽⁹⁾	320	329	320	346

⁽¹⁾ Due to the nature and/or short-term maturity of these financial instruments, carrying value approximates fair value.

⁽²⁾ Included in accounts receivable on the balance sheet

⁽³⁾ Carrying value approximates amortized cost

⁽⁴⁾ Included in deferred charges and other assets on the balance sheet

⁽⁵⁾ Included in accounts payable and accrued charges on the balance sheet

⁽⁶⁾ Included in deferred credits on the balance sheet

⁽⁷⁾ Carrying value is measured at amortized cost using the effective interest rate method.

⁽⁸⁾ Carrying value at December 31, 2008 is net of unamortized deferred financing costs of \$34 million (December 31, 2007 – \$33 million).

⁽⁹⁾ Preference shares classified as equity are excluded from the requirements of CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*; however, the estimated fair value of the Corporation's \$347 million preference shares classified as equity was \$268 million as at December 31, 2008 (December 31, 2007 – carrying value \$122 million; fair value \$107 million).

The carrying values of financial instruments included in current assets, current liabilities, deferred charges and other assets, and deferred credits in the consolidated balance sheets approximate their fair value, reflecting the short-term maturity, normal trade credit terms and/or the nature of these instruments. The fair value of long-term debt is calculated by using quoted market prices, when available. When quoted market prices are not available, the fair value is determined by discounting the future cash flows of the specific debt instrument at an estimated yield to maturity equivalent to benchmark government bonds or treasury bills, with similar terms to maturity, plus a market credit risk premium equal to that of issuers of similar credit quality. Since the Corporation does not intend to settle the long-term debt prior to maturity, the fair value estimate does not represent an actual liability and, therefore, does not include exchange or settlement costs. The fair value of the Corporation's preference shares is determined using quoted market prices.

The Corporation and its subsidiaries hedge exposures to fluctuations in interest rates, foreign exchange rates and natural gas prices through the use of derivative financial instruments. The Corporation does not hold or issue derivative financial instruments for trading purposes. The following table summarizes the valuation of the Corporation's derivative financial instruments as at December 31.

Asset (Liability)	2008				2007	
	Term to Maturity (years)	Number of Contracts	Carrying Value (in millions)	Estimated Fair Value (in millions)	Carrying Value (in millions)	Estimated Fair Value (in millions)
Interest rate swaps ⁽¹⁾	1 to 2	2	\$ –	\$ –	\$ –	\$ –
Foreign exchange forward contract	< 3	1	7	7	–	–
Natural gas derivatives: ⁽²⁾						
Swaps and options	Up to 3	228	(84)	(84)	(79)	(79)
Gas purchase contract premiums	Up to 3	74	(8)	(8)	5	5

⁽¹⁾ Interest rate swap contracts mature in July 2009 and October 2010. The contracts have the effect of fixing the rate of interest on the non-revolving credit facilities of Fortis Properties at 6.16 per cent and 5.32 per cent, respectively.

⁽²⁾ The fair values of the natural gas derivatives were recorded in accounts payable as at December 31, 2008 (December 31, 2007 – in accounts payable and accounts receivable).

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

25. Financial Instruments (cont'd)

The fair value of the Corporation's financial instruments, including derivatives, reflects a point-in-time estimate based on current and relevant market information about the instruments as at the balance sheet dates. The estimates cannot be determined with precision as they involve uncertainties and matters of judgment and, therefore, may not be relevant in predicting the Corporation's future earnings or cash flows.

26. Financial Risk Management

The Corporation is primarily exposed to credit risk, liquidity risk and market risk as a result of holding financial instruments in the normal course of business.

Credit risk Risk that a third party to a financial instrument might fail to meet its obligations under the terms of the financial instrument.

Liquidity risk Risk that an entity will encounter difficulty in raising funds to meet commitments associated with financial instruments.

Market risk Risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in market prices. The Corporation is exposed to the following market risks:

- Foreign exchange risk
- Interest rate risk
- Commodity price risk

Credit Risk

For cash and cash equivalents, trade and other accounts receivable, and other receivables due from customers, the Corporation's credit risk is limited to the carrying value on the balance sheet. The Corporation generally has a large and diversified customer base, which minimizes the concentration of credit risk. The Corporation and its subsidiaries have various policies to minimize credit risk, which include requiring customer deposits and credit checks for certain customers and performing disconnections and/or using third-party collection agencies for overdue accounts.

FortisAlberta has a concentration of credit risk as a result of its distribution-service billings being to a relatively small group of retailers and, as at December 31, 2008, its gross credit risk exposure was approximately \$87 million, representing the projected value of retailer billings over a 60-day period. The Company has reduced its exposure to approximately \$3 million by obtaining from the retailers either a cash deposit, bond, letter of credit, an investment-grade credit rating from a major rating agency or by having the retailer obtain a financial guarantee from an entity with an investment-grade credit rating.

The aging analysis of the Corporation's consolidated trade and other accounts receivable is as follows:

<i>(in millions)</i>	As at December 31, 2008	
Not past due	\$	587
Past due 0–30 days		70
Past due 31–60 days		14
Past due 61 days and over		19
		690
Less: allowance for doubtful accounts		(16)
	\$	674

As at December 31, 2008, other receivables due from customers of \$8 million and the receivable associated with the foreign exchange forward contract of \$7 million will be received over the next six years, with \$7 million expected to be received in 2009, \$5 million over 2010 and 2011, \$2 million over 2012 and 2013 and \$1 million in 2014.

Liquidity Risk

The Corporation's financial position could be adversely affected if it, or its operating subsidiaries, fail to arrange sufficient and cost-effective financing to fund, among other things, capital expenditures and the repayment of maturing debt. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the results of operations and financial position of the Corporation and its subsidiaries, conditions in the capital and bank credit markets, ratings assigned by rating agencies and general economic conditions.

To mitigate liquidity risk, the Corporation and its larger regulated utilities have secured committed credit facilities to support short-term financing of capital expenditures and seasonal working capital requirements.

Notes to Consolidated Financial Statements

Committed credit facilities at Fortis are available for interim financing of acquisitions and for general corporate purposes. Depending on the timing of cash payments from the subsidiaries, borrowings under the Corporation's committed credit facility may be required from time to time to support the servicing of debt and payment of dividends. Over the next five years, average consolidated annual long-term debt maturities and repayments are expected to be approximately \$180 million. The combination of available credit facilities and low annual debt maturities and repayments provide the Corporation and its subsidiaries with flexibility in the timing and access to capital markets.

As at December 31, 2008, the Corporation and its subsidiaries had consolidated credit facilities of \$2.2 billion, of which \$1.5 billion was unused. The credit facilities are syndicated almost entirely with the seven largest Canadian banks with no one bank holding more than 25 per cent of these facilities.

The following summary outlines the credit facilities of the Corporation and its subsidiaries.

<i>(in millions)</i>	Corporate and Other	Regulated Utilities	Fortis Properties	Total as at December 31, 2008	Total as at December 31, 2007
Total credit facilities	\$ 715	\$ 1,500	\$ 13	\$ 2,228	\$ 2,234
Credit facilities utilized:					
Short-term borrowings	—	(410)	—	(410)	(475)
Long-term debt <i>(Note 10)⁽¹⁾</i>	(32)	(192)	—	(224)	(530)
Letters of credit outstanding	(1)	(102)	(1)	(104)	(159)
Credit facilities available	\$ 682	\$ 796	\$ 12	\$ 1,490	\$ 1,070

⁽¹⁾ As at December 31, 2008, credit-facility borrowings classified as long-term debt included \$8 million that was included in current installments of long-term debt and capital lease obligations on the balance sheet.

As at December 31, 2008 and December 31, 2007, certain borrowings under the Corporation's and its subsidiaries' credit facilities have been classified as long-term debt. These borrowings are under long-term committed credit facilities and management's intention is to refinance these borrowings with long-term permanent financing during future periods.

Corporate and Other

Terasen Inc. has a \$100 million unsecured committed revolving credit facility, maturing May 2009, that is available for general corporate purposes. Letters of credit of \$50 million previously outstanding at Terasen Inc., related to its previously owned petroleum transportation business and secured by a letter of credit from the former parent company, were cancelled during the second quarter of 2008.

Fortis has a \$600 million unsecured committed revolving credit facility, maturing May 2012, and a \$15 million unsecured demand facility. Both facilities are available for general corporate purposes and the committed facility is also available for interim financing of acquisitions.

Regulated Utilities

TGI has a \$500 million unsecured committed revolving credit facility, maturing August 2013. TGVI has a \$350 million unsecured committed revolving credit facility, maturing January 2011. The facilities are utilized to finance working capital requirements and capital expenditures, and for general corporate purposes. TGVI also has a \$20 million subordinated unsecured committed non-revolving credit facility, maturing in January 2013. This facility can only be utilized for refinancing annual repayments on non-interest bearing government loans.

FortisAlberta has a \$200 million unsecured committed revolving credit facility, maturing May 2012, utilized to finance capital expenditures and for general corporate purposes and, with the consent of the lenders, the amount of the facility can be increased to \$250 million. FortisAlberta also has a \$10 million unsecured demand credit facility.

FortisBC has a \$150 million unsecured committed revolving credit facility of which \$50 million matures May 2011 and the remaining \$100 million matures May 2009. Additionally, the Company has the option to increase the credit facility to an aggregate of \$200 million, subject to bank approval. This facility is utilized to finance capital expenditures and for general corporate purposes. FortisBC also has a \$10 million unsecured demand facility.

Newfoundland Power has \$120 million of unsecured credit facilities, comprised of a \$100 million committed revolving credit facility, which matures August 2011, and a \$20 million uncommitted demand facility.

Maritime Electric had a \$50 million unsecured demand revolving credit facility at December 31, 2008. In March 2009, the credit facility was renegotiated and converted into a 364-day revolving committed credit facility.

FortisOntario has secured lines of credit totalling \$20 million of which \$12 million is authorized solely for letters of credit.

Notes to Consolidated Financial Statements

December 31, 2008 and 2007

26. Financial Risk Management (cont'd)

Regulated Utilities (cont'd)

Caribbean Utilities has credit facilities of US\$33 million (\$40 million), comprised of a capital expenditure line of credit of US\$18 million (\$22 million), including amounts available for letters of credit, a US\$7.5 million (\$9 million) operating line of credit and a US\$7.5 million (\$9 million) catastrophe standby loan.

Fortis Turks and Caicos has credit facilities of US\$21 million (\$25.5 million), comprised of an operating credit facility of US\$5 million (\$6 million), a capital expenditure line of credit of US\$7 million (\$8.5 million) and a US\$9 million (\$11 million) emergency standby loan.

Belize Electricity has a BZ\$2 million (\$1 million) and BZ\$5 million (\$3 million) demand overdraft credit facility with Belize Bank Limited and Scotiabank, respectively.

In November 2008, First Caribbean International Bank withdrew its credit facility with Belize Electricity requiring the Company to repay approximately BZ\$4 million (\$2 million) outstanding under the facility. Scotiabank has also put Belize Electricity on notice that it may not renew its BZ\$5 million (\$3 million) credit facility with the Company if financial conditions do not show signs of improvement. As at December 31, 2008, the credit facility was undrawn.

Fortis Properties

Fortis Properties has a \$13 million secured revolving demand facility utilized for general corporate purposes.

Furthermore, the Corporation and its currently rated subsidiaries target investment-grade credit ratings to maintain capital market access at reasonable interest rates. As at December 31, 2008, the Corporation's credit ratings were as follows:

Standard & Poor's	A- (long-term corporate and unsecured debt credit rating)
DBRS	BBB(high) (unsecured debt credit rating)

The credit ratings reflect the diversity of the operations of Fortis, the stand-alone nature and financial separation of each of the regulated subsidiaries of Fortis, management's commitment to maintaining low levels of debt at the holding company level and the continued focus of Fortis on pursuing the acquisition of stable regulated utilities.

The following is an analysis of the contractual maturities of the Corporation's financial liabilities as at December 31, 2008.

Financial Liabilities

(in millions)	≤ 1 year	>1-3 years	4-5 years	>5 years	Total
Short-term borrowings	\$ 410	\$ -	\$ -	\$ -	\$ 410
Trade and other accounts payable	782	-	-	-	782
Natural gas derivatives	70	22	-	-	92
Dividends payable	47	-	-	-	47
Customer deposits	2	2	1	1	6
Long-term debt, including current portion ⁽¹⁾	240	319	335	4,228	5,122
Interest obligations on long-term debt	304	698	583	3,993	5,578
Preference shares, classified as debt	-	-	-	320	320
	\$ 1,855	\$ 1,041	\$ 919	\$ 8,542	\$ 12,357

⁽¹⁾ Excluding deferred financing costs of \$34 million included in the carrying value as per Note 25

Market Risk

Foreign Exchange Risk

The Corporation's earnings from, and net investment in, its self-sustaining foreign subsidiaries are exposed to fluctuations in the US dollar-to-Canadian dollar exchange rate. The Corporation has effectively decreased the above exposure through the use of US dollar borrowings at the corporate level. The foreign exchange gain or loss on the translation of US dollar-denominated interest expense partially offsets the foreign exchange loss or gain on the translation of the Corporation's foreign subsidiaries' earnings, which are denominated in US dollars or in a currency pegged to the US dollar. Belize Electricity's reporting currency is the Belizean dollar while the reporting currency of Caribbean Utilities, Fortis Turks and Caicos, FortisUS Energy and BECOL is the US dollar. The Belizean dollar is pegged to the US dollar at BZ\$2.00 = US\$1.00.

Notes to Consolidated Financial Statements

As at December 31, 2008, all of the Corporation's corporately held US\$403 million of long-term debt had been designated as a hedge of a portion of the Corporation's foreign net investments. As at December 31, 2008, the Corporation had approximately US\$119 million in foreign net investments remaining to be hedged. Foreign currency exchange rate fluctuations associated with the translation of the Corporation's corporately held US dollar borrowings that are designated as hedges are recorded in other comprehensive income and serve to help offset unrealized foreign currency exchange gains and losses on the foreign net investments, which are also recorded in other comprehensive income.

A 5 per cent appreciation of the US dollar relative to the Canadian dollar would have increased earnings by \$0.6 million for the year ended December 31, 2008 and would have decreased other comprehensive income by \$25 million for the year ended December 31, 2008. This sensitivity analysis is limited to the net impact on earnings of the translation of US dollar interest expense and earnings' streams from the Corporation's foreign subsidiaries and the impact on other comprehensive income of the translation of the US dollar borrowings. The sensitivity analysis excludes the risk arising from the translation of self-sustaining foreign net investments to the Canadian dollar because such investments are not financial instruments. However, a 5 per cent appreciation of the US dollar relative to the Canadian dollar associated with the translation of the Corporation's net investment in self-sustaining foreign subsidiaries would have increased other comprehensive income by \$32 million for the year ended December 31, 2008.

TGVI's US dollar payments under a contract for the construction of an LNG storage facility exposes TGVI to fluctuations in the US dollar-to-Canadian dollar exchange rate. TGVI has entered into a foreign exchange forward contract to hedge this exposure. At December 31, 2008, a 5 per cent appreciation of the US dollar relative to the Canadian dollar, as it affects the measurement of the fair value of the foreign exchange forward contract, in the absence of rate regulation and with all other variables remaining constant, would have increased earnings by \$3 million for the year ended December 31, 2008. Furthermore, TGVI has regulatory approval to defer any increase or decrease in the fair value of the foreign exchange forward contract for recovery from, or refund to, customers in future rates. Therefore, any change in fair value would have impacted regulatory assets or liabilities rather than other comprehensive income.

Interest Rate Risk

The Corporation and its subsidiaries are exposed to interest rate risk associated with short-term borrowings and floating-rate debt. The Corporation and its subsidiaries may enter into interest rate swap agreements to help reduce this risk and, during 2008, the Terasen Gas companies and Fortis Properties were parties to interest rate swap agreements that effectively fixed the interest rates on their variable-rate borrowings. During the fourth quarter of 2008, the Terasen Gas companies' interest rate swaps matured. A 100 basis point increase in interest rates associated with variable-rate debt, with all other variables remaining constant, would have decreased earnings by \$5 million for the year ended December 31, 2008. Furthermore, the Terasen Gas companies and FortisBC have regulatory approval to defer any increase or decrease in interest expense resulting from fluctuations in interest rates associated with variable-rate debt for recovery from, or refund to, customers in future rates.

As at December 31, 2008, a 100 basis point increase in interest rates as it affects the measurement of fair value of the interest rate swap agreements would have increased other comprehensive income by \$0.1 million during the year ended December 31, 2008.

In addition, certain of the committed credit facilities have fees that are linked to the Corporation's or its subsidiaries' credit ratings. A downward change in the credit ratings of the Corporation and its currently rated subsidiaries by one level, with all other variables remaining constant, would have decreased earnings by \$0.9 million for the year ended December 31, 2008.

Commodity Price Risk

The Terasen Gas companies are exposed to commodity price risk associated with changes in the market price of natural gas. This risk is minimized by entering into natural gas derivatives that effectively fix the price of natural gas purchases. The natural gas derivatives are recorded on the balance sheet at fair value and any change in the fair value is deferred as a regulatory asset or liability, subject to regulatory approval, for recovery from, or refund to, customers in future rates.

Had the price of natural gas, with all other variables remaining constant, increased by \$1 per gigajoule, the fair value of the natural gas derivatives would have increased and, in the absence of rate regulation, other comprehensive income would have increased by \$54 million for the year ended December 31, 2008. However, the Terasen Gas companies defer any changes in fair value of the natural gas derivatives, subject to regulatory approval, for future recovery from, or refund to, customers in future rates. Therefore, instead of increasing other comprehensive income, current regulatory assets would have decreased by \$54 million.

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27. Commitments

(in millions)	Total	< 1 year	1–3 years	4–5 years	> 5 years
Gas purchase contract obligations ⁽¹⁾	\$ 466	\$ 416	\$ 50	\$ –	\$ –
Power purchase obligations					
FortisBC ⁽²⁾	2,829	40	76	78	2,635
FortisOntario ⁽³⁾	561	45	94	99	323
Maritime Electric ⁽⁴⁾	72	52	2	2	16
Belize Electricity ⁽⁵⁾	16	4	4	2	6
Capital cost ⁽⁶⁾	400	16	41	41	302
Joint-use asset and shared service agreements ⁽⁷⁾	62	4	7	6	45
Office lease – FortisBC ⁽⁸⁾	19	1	4	2	12
Operating lease obligations ⁽⁹⁾	166	18	33	29	86
Other	25	4	10	6	5
Total	\$ 4,616	\$ 600	\$ 321	\$ 265	\$ 3,430

⁽¹⁾ Gas purchase contract obligations relate to various gas purchase contracts at the Terasen Gas companies. These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at December 31, 2008.

⁽²⁾ Power purchase obligations of FortisBC include the Brilliant Power Purchase Agreement (the “BPPA”) as well as the power purchase agreement with BC Hydro. On May 3, 1996, an Order was granted by the BCUC approving a 60-year BPPA for the output of the Brilliant hydroelectric generating plant located near Castlegar, British Columbia. The BPPA requires payments based on the operation and maintenance costs and a return on capital for the plant in exchange for the specified natural flow take-or-pay amounts of power. The BPPA includes a market-related price adjustment after 30 years of the 60-year term. The power purchase agreement with BC Hydro, which expires in 2013, provides for any amount of supply up to a maximum of 200 MW but includes a take-or-pay provision based on a five-year rolling nomination of the capacity requirements.

⁽³⁾ Power purchase obligations for FortisOntario primarily include two long-term take-or-pay contracts between Cornwall Electric and Hydro-Québec Energy Marketing for the supply of electricity and capacity. The first contract provides approximately 237 gigawatt hours (“GWh”) of energy per year and up to 45 MW of capacity at any one time. The second contract, supplying the remainder of Cornwall Electric’s energy requirements, provides 100 MW of capacity and energy and provides a minimum of 300 GWh of energy per contract year. Both contracts expire in December 2019.

⁽⁴⁾ Maritime Electric has two take-or-pay contracts for the purchase of either capacity or energy. The contracts total approximately \$72 million through November 30, 2032. The take-or-pay contract with New Brunswick Power (“NB Power”) includes, among other things, replacement energy and capacity for the NB Power Point Lepreau Nuclear Generating Station during its refurbishment outage. The other take-or-pay contract is for transmission capacity allowing Maritime Electric to reserve 30 MW of capacity on the new International Power Line into the United States.

⁽⁵⁾ Power purchase obligations for Belize Electricity include a 15-year power purchase agreement, which commenced in February 2007, between Belize Electricity and Hydro Maya Limited for the supply of 3 MW of capacity and a two-year power purchase agreement, expiring in December 2010, between Belize Electricity and Comisión Federal de Electricidad of Mexico for the supply of 50 MW of firm capacity and associated energy. Belize Electricity has also signed two 15-year power purchase agreements with Belize Cogeneration Energy Limited (“Belcogen”) and Belize Aquaculture Limited that provide for the supply of approximately 14 MW of capacity and up to 15 MW of capacity, respectively. As the generating plants are not yet connected to the electricity system, the obligations related to the power purchase agreements with Belcogen and Belize Aquaculture Limited have not been included in the Corporation’s commitments table above.

⁽⁶⁾ Maritime Electric has entitlement to approximately 6.7 per cent of the output from the NB Power Dalhousie Generating Station and approximately 4.7 per cent from the NB Power Point Lepreau Nuclear Generating Station for the life of each unit. As part of its participation agreement, Maritime Electric is required to pay its share of the capital costs of these units.

Notes to Consolidated Financial Statements

⁽⁷⁾ FortisAlberta and an Alberta transmission service provider have entered into an agreement in consideration for joint attachments of distribution facilities to the transmission system. The expiry terms of this agreement state that the agreement remains in effect until the Company no longer has attachments to the transmission facilities. Due to the unlimited term of this contract, the calculation of future payments after 2013 includes payments to the end of 20 years. However, the payments under this agreement may continue for an indefinite period of time. FortisAlberta and an Alberta transmission service provider have also entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The service agreements have minimum expiry terms of five years from September 1, 2005 and are subject to extensions based on mutually agreeable terms.

⁽⁸⁾ Under a sale-leaseback agreement, on September 29, 1993, FortisBC began leasing its Trail, British Columbia office building for a term of 30 years. The terms of the agreement grant FortisBC repurchase options at approximately year 20 and year 28 of the lease term.

⁽⁹⁾ Operating lease obligations include certain office, warehouse, natural gas transmission and distribution asset, and vehicle and equipment leases, and the lease of electricity distribution assets of Port Colborne Hydro Inc.

The Corporation's regulated utilities are obligated to provide service to customers within their respective service territories. The regulated utilities' capital expenditures are largely driven by customer requests and by large capital projects specifically approved by their respective regulatory authorities. The consolidated capital program of the Corporation, including non-regulated segments, is forecasted to be approximately \$1 billion for 2009. This commitment has not been included in the commitments table above.

In prior years, TGVl received non-interest bearing repayable loans from the federal and provincial governments of \$50 million and \$25 million, respectively, in connection with the construction and operation of the Vancouver Island natural gas pipeline. As approved by the BCUC, these loans have been recorded as government grants and have reduced the amounts reported for utility capital assets. The government loans are repayable in any fiscal year prior to 2012 under certain circumstances and are subject to the ability of TGVl to obtain non-government subordinated debt financing on reasonable commercial terms. As the loans are repaid and replaced with non-government loans, utility capital assets and long-term debt will increase in accordance with TGVl's approved capital structure, as will TGVl's rate base, which is used in determining customer rates.

The repayment criteria were met in 2008 and TGVl is expected to make an \$8 million repayment on the loans in 2009 (2008 – \$6 million). As at December 31, 2008, the outstanding balance of the repayable government loans was \$61 million with \$8 million classified as current portion of long-term debt. Repayments of the government loans beyond 2009 are not included in the commitments table above as the amount and timing of the repayments are dependent upon annual BCUC approval of the recovery of TGVl's RDDA and the ability of TGVl to replace the government loans with non-government subordinated debt financing on reasonable commercial terms.

Caribbean Utilities has a primary fuel supply contract with a major supplier and is committed to purchase 80 per cent of the Company's fuel requirements from this supplier for the operation of Caribbean Utilities' diesel-fired generating plant. The contract is for three years terminating in April 2010. The remaining approximate quantities, in millions of imperial gallons, required to be purchased annually for each of the 12-month periods ended December 31 are: 2009 – 27 and 2010 – 9.

Fortis Turks and Caicos has a renewable contract with a major supplier for all of its diesel fuel requirements associated with the generation of electricity. The approximate fuel requirements under this contract are 12 million imperial gallons per annum.

Based on the last completion of actuarial valuations, the Corporation's required consolidated defined benefit pension plan funding contributions are expected to be approximately \$17 million for 2009 and \$12 million for 2010. The level of the defined benefit pension plan funding contributions will be affected by the outcome, in 2009, of December 31, 2008 actuarial valuations for Newfoundland Power, the Corporation and one of the defined benefit pension plans at Terasen. The next scheduled actuarial valuations for the remaining larger defined benefit pension plans are not until December 2009 and December 2010.

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December 31, 2008 and 2007

28. Contingent Liabilities

The Corporation and its subsidiaries are subject to various legal proceedings and claims associated with ordinary course business operations. Management believes that the amount of liability, if any, from these actions would not have a material effect on the Corporation's consolidated financial position or results of operations.

The following describes the nature of the Corporation's contingent liabilities.

Terasen

On March 26, 2007, the Minister of Small Business and Revenue and Minister Responsible for Regulatory Reform (the "Minister") in British Columbia issued a decision in respect of the appeal by TGI of an assessment of additional British Columbia Social Service Tax in the amount of approximately \$37 million associated with the Southern Crossing Pipeline, which was completed in 2000. The Minister reduced the assessment to \$7 million, including interest, which has been paid in full to avoid accruing further interest and it is recorded as a long-term regulatory deferral asset. The matter is currently under appeal to the Supreme Court of British Columbia (Note 4 (ix)).

During 2007 and 2008, a non-regulated subsidiary of Terasen received Notices of Assessment from Canada Revenue Agency ("CRA") for additional taxes related to the taxation years 1999 through 2003. The exposure has been fully provided for in the consolidated financial statements. Terasen has begun the appeal process associated with the assessments.

In 2008, the Vancouver Island Gas Joint Venture commenced a claim against TGI seeking damages for alleged past overpayments and a future reduction in tolls. The Statement of Claim does not quantify damages and, as such, the Company cannot determine the amount of the claim at this time. It is the Company's view that the claim is without merit. No amount, therefore, has been accrued in the consolidated financial statements.

FortisBC

The British Columbia Ministry of Forests has alleged breaches of the Forest Practices Code and negligence relating to a fire near Vaseux Lake and has filed and served a writ and statement of claim against FortisBC. In addition, the Company has been served with a filed writ and statement of claim by a private landowner in relation to the same matter. The Company is currently communicating with its insurers and has filed a statement of defence in relation to all of the actions. The outcome cannot be reasonably determined and estimated at this time and, accordingly, no amount has been accrued in the consolidated financial statements.

Maritime Electric

In April 2006, CRA reassessed Maritime Electric's 1997–2004 taxation years. The reassessment encompasses the Company's tax treatment, specifically the Company's timing of deductions, with respect to: (i) the ECAM in the 2001–2004 taxation years; (ii) customer rebate adjustments in the 2001–2003 taxation years; and (iii) the Company's payment of approximately \$6 million on January 2, 2001 associated with a settlement with NB Power regarding its \$450 million write-down of the NB Power Point Lepreau Nuclear Generating Station in 1998. Maritime Electric believes it has reported its tax position appropriately in all respects and has filed a Notice of Objection with the Chief of Appeals at CRA. In December 2008, the Appeals Division of CRA issued a Notice of Confirmation which confirmed the April 2006 reassessments. The Company will file an Appeal to the Tax Court of Canada.

Should the Company be unsuccessful in defending all aspects of the reassessment, the Company would be required to pay approximately \$13 million in taxes and accrued interest. As at December 31, 2008, Maritime Electric has provided for this amount through future and current income taxes payable. The provisions of the *Income Tax Act* (Canada) require the Company to deposit one-half of the assessment under objection with CRA. The amount currently on deposit with CRA arising from the reassessment is approximately \$6 million.

FortisUS Energy

During 2008, a statutory discontinuance and final release of FortisUS Energy was issued in relation to legal proceedings initiated by the Village of Philadelphia (the "Village"), New York. The Village had claimed that FortisUS Energy should honour a series of current and future payments set out in an agreement between the Village and a former owner of the hydroelectric site, located in the municipality of the Village, now owned by FortisUS Energy, totalling approximately \$9 million (US\$7 million). There was no impact on the consolidated financial statements as a result of the settlement of these legal proceedings.

Notes to Consolidated Financial Statements

Exploits Partnership

On December 16, 2008, the Government of Newfoundland and Labrador passed legislation expropriating most of the Newfoundland assets of Abitibi-Consolidated. Prior to that date, Abitibi-Consolidated announced the closure of its Grand Falls-Windsor, Newfoundland newsprint mill, effective March 31, 2009. The hydroelectric generating facility assets of the Exploits Partnership were included as part of the expropriation legislation. The Exploits Partnership is owned 51 per cent by Fortis Properties and 49 per cent by Abitibi-Consolidated. The financial statements of the Exploits Partnership are consolidated in the financial statements of Fortis. The Exploits Partnership has a \$61 million term loan, which is non-recourse to Fortis, with several lenders which is secured by the assets of the Exploits Partnership.

Discussions are ongoing with the Exploits Partnership's lenders with respect to the above matters. The Government of Newfoundland and Labrador has publicly stated that it is not its intention to adversely affect the business interests of lenders or independent partners of Abitibi-Consolidated. Pending resolution of these matters, the deferred financing costs of \$2 million and utility capital assets of \$61 million related to the Exploits Partnership have been reclassified to deferred charges and other assets and the \$61 million term loan has been classified as current on the consolidated balance sheet of Fortis as at December 31, 2008.

29. Subsequent Events

In February 2009, FortisAlberta issued \$100 million of 30-year 7.06% unsecured debentures under the short-form base shelf prospectus that was filed in December 2008. The net proceeds were used to repay committed credit-facility borrowings incurred in support of the Company's capital expenditure program and for general corporate purposes.

In February 2009, TGI issued \$100 million of 30-year 6.55% unsecured debentures. The net proceeds are being used to repay credit-facility borrowings incurred in support of working capital requirements and capital expenditures, and to repay \$60 million of unsecured debentures that mature in June 2009.

30. Comparative Figures

Certain comparative figures have been reclassified to comply with the current year's classifications.

Historical Financial Summary

Statements of Earnings (in \$ millions)	2008	2007	2006⁽¹⁾	2005⁽¹⁾
Revenue, including equity income	3,903	2,718	1,472	1,441
Energy supply costs and operating expenses	2,855	1,904	939	926
Amortization	348	273	178	158
Finance charges	363	299	168	154
Corporate taxes	65	36	32	70
Results of discontinued operations,				
gains on sales and other unusual items	–	8	2	10
Non-controlling interest	13	15	8	6
Preference share dividends	14	6	2	–
Net earnings applicable to common shares	245	193	147	137
Balance Sheets (in \$ millions)				
Current assets	1,150	1,038	405	299
Goodwill	1,575	1,544	661	512
Other long-term assets	545	424	331	471
Utility capital assets and income producing properties	7,908	7,267	4,044	3,315
Total assets	11,178	10,273	5,441	4,597
Current liabilities	1,697	1,804	558	412
Deposits due beyond one year	–	–	–	–
Deferred credits, regulatory liabilities and future income taxes	739	688	477	477
Long-term debt and capital lease obligations				
(excluding current portion)	4,884	4,623	2,558	2,136
Non-controlling interest	145	115	130	39
Preference share (classified as debt)	320	320	320	320
Shareholders' equity	3,393	2,723	1,398	1,213
Cash Flows (in \$ millions)				
Operating activities	663	373	263	304
Investing activities	854	2,033	634	467
Financing activities	387	1,826	456	224
Dividends, excluding dividends on preference shares				
classified as debt	191	146	77	64
Financial Statistics				
Return on average common shareholders' equity (%)	8.70	10.00	11.87	12.40
Capitalization Ratios (%) (year end)				
Total debt and capital lease obligations (net of cash)	59.5	64.3	61.1	58.7
Preference shares (classified as debt and equity)	7.3	5.2	10.0	8.6
Common shareholders' equity	33.2	30.5	28.9	32.7
Interest Coverage (x)				
Debt	1.9	1.9	2.2	2.5
All fixed charges	1.8	1.7	2.0	2.1
Total gross capital expenditures (in \$ millions)	904	803	500	446
Common share data				
Book value per share (year end) (\$)	17.97	16.69	12.19	11.74
Average common shares outstanding (in millions)	157.4	137.6	103.6	101.8
Basic earnings per common share (\$)	1.56	1.40	1.42	1.35
Dividends declared per common share (\$)	1.010	0.880	0.700	0.605
Dividends paid per common share (\$)	1.000	0.820	0.670	0.588
Dividend payout ratio (%)	64.1	58.6	47.2	43.7
Price earnings ratio (x)	15.8	20.7	21.0	18.0
Share trading summary				
High price (\$) (TSX)	29.94	30.00	30.00	25.64
Low price (\$) (TSX)	20.70	24.50	20.36	17.00
Closing price (\$) (TSX)	24.59	28.99	29.77	24.27
Volume (in thousands)	132,108	100,920	60,094	37,706

⁽¹⁾ As at December 31, 2006, the regulatory provision for future asset removal and site restoration costs was reallocated from accumulated amortization to long-term regulatory liabilities, with 2005 comparative figures restated. The effect of this change in presentation at December 31, 2006 was a \$306.5 million (December 31, 2005 – \$280.9 million) increase in long-term regulatory liabilities and a \$306.5 million (December 31, 2005 – \$280.9 million) increase in net utility capital assets.

2004	2003	2002	2001	2000	1999	1998
1,146	843	715	628	580	505	473
766	579	477	418	418	356	340
114	62	65	62	52	45	42
122	86	74	65	56	46	44
47	38	32	29	17	28	23
–	–	–	4	3	–	4
6	4	4	4	3	1	1
–	–	–	–	–	–	–
91	74	63	54	37	29	27
293	191	180	135	166	93	94
514	65	60	33	36	39	42
418	345	241	172	163	122	121
2,713	1,563	1,459	1,246	1,056	930	750
3,938	2,164	1,940	1,586	1,421	1,184	1,007
538	296	334	272	225	230	148
–	–	–	–	–	16	16
138	62	39	32	24	27	22
1,905	1,031	941	746	678	488	424
37	37	40	36	32	29	8
320	123	–	50	50	50	50
1,000	615	586	450	412	344	339
272	157	134	94	97	85	69
1,026	308	349	240	241	122	66
777	232	261	171	178	67	16
51	38	35	30	28	24	24
11.28	12.30	12.23	12.44	9.73	8.55	8.24
61.4	60.0	65.2	63.9	60.4	59.6	53.4
9.4	6.7	–	3.6	4.3	5.1	6.0
29.2	33.3	34.8	32.5	35.3	35.3	40.6
2.3	2.2	2.3	2.3	2.1	2.3	2.2
2.0	2.1	2.2	2.2	1.9	2.1	2.0
279	208	229	149	158	86	65
10.45	8.82	8.50	7.50	6.97	6.55	6.52
84.7	69.3	65.1	59.5	54.1	52.2	51.5
1.07	1.06	0.97	0.90	0.68	0.56	0.53
0.548	0.525	0.498	0.470	0.460	0.455	0.450
0.540	0.520	0.485	0.468	0.460	0.453	0.450
50.3	48.9	49.9	51.9	67.6	80.8	84.9
16.2	13.9	13.5	13.0	13.2	14.0	18.0
17.75	15.24	13.28	11.89	9.19	9.93	12.03
14.23	11.63	10.76	8.56	6.88	7.29	8.75
17.38	14.73	13.13	11.74	9.00	7.85	9.56
29,254	31,180	21,676	21,460	26,760	9,024	12,356



Board of Directors (l-r): David G. Norris, Peter E. Case, Harry McWatters, John S. McCallum, Geoffrey F. Hyland, Roy P. Rideout, Linda L. Inkpen, Michael A. Pavey, H. Stanley Marshall, Frank J. Crothers

Board of Directors

Geoffrey F. Hyland *** *Chair, Fortis Inc., Caledon, ON*

Mr. Hyland, 64, joined the Fortis Inc. Board in May 2001 and was appointed Chair of the Board in May 2008. He retired as President and CEO of Shawcor Ltd. in June 2005 after 37 years of service. Mr. Hyland is a Director of FortisOntario Inc. He continues to serve on the Board of ShawCor Ltd. and is a Director of Enerflex Systems Income Fund, SCIT Total Return Trust and Exco Technologies Limited.

Peter E. Case * *Corporate Director, Freelon, ON*

Mr. Case, 54, joined the Fortis Inc. Board in May 2005. After 17 years as a utility and pipeline analyst, he retired in February 2003 as Executive Director, Institutional Equity Research at CIBC World Markets. Prior to that position, he was Managing Director at BMO Nesbitt Burns. Mr. Case has been a Director of FortisOntario Inc. since March 2003.

Frank J. Crothers *Chairman & CEO, Island Corporate Holdings, Nassau, Bahamas*
Mr. Crothers, 64, joined the Fortis Inc. Board in May 2007. Over the past 35 years, Mr. Crothers has served on many public and private sector boards. He served a three-year term as Chairman of CARILEC, the Caribbean Association of Electrical Utilities. Mr. Crothers is the former President of P.P.C. Limited, which was acquired by Fortis Inc. in August 2006. He serves as Vice Chair of the Board of Caribbean Utilities Company, Limited and serves on the Board of Belize Electricity. Mr. Crothers also serves as a Director of Franklin Templeton Resources, Talon Metals Corp, Fidelity Merchant Bank & Trust (Cayman) Limited and Victory Nickel Inc.

Linda L. Inkpen * *Corporate Director, St. John's, NL*

Dr. Inkpen, 61, joined the Fortis Inc. Board in 1994. She retired from her medical practice in December 2008 after 35 years of service and is past Chair of the Medical Advisory Committee for the St. John's Hospitals for Eastern Health. Dr. Inkpen is a past President of the College of the North Atlantic. She also served on the Royal Commission on Employment and Unemployment. Dr. Inkpen is past Chair of the Boards of Fortis Properties Corporation and Newfoundland Power Inc. She will be retiring from the Fortis Inc. Board at the Annual Meeting on May 5, 2009.

H. Stanley Marshall *President and CEO, Fortis Inc., St. John's, NL*

Mr. Marshall, 58, has served on the Fortis Inc. Board since 1995. He joined Newfoundland Power Inc. in 1979 and was appointed President and CEO of Fortis Inc. in 1996. Mr. Marshall serves on the Boards of all Fortis utilities in western Canada and the Caribbean and the Board of Fortis Properties Corporation. He is also a Director of Toromont Industries Ltd.

John S. McCallum ** *Professor of Finance, University of Manitoba, Winnipeg, MB*

Mr. McCallum, 65, joined the Fortis Inc. Board in July 2001 and is Chair of the Governance and Nominating Committee of the Board. He was Chairman of Manitoba Hydro from 1991 to 2000 and Policy Advisor to the Federal Minister of Finance from 1984 to 1991. Mr. McCallum is a Director of FortisBC Inc. and FortisAlberta Inc. He also serves as a Director of IGM Financial Inc., Toromont Industries Ltd. and Wawanesa.

Harry McWatters * *Wine Consultant, Summerland, BC*

Mr. McWatters, 63, joined the Fortis Inc. Board in May 2007. He is the founder and past President of Sumac Ridge Estate Wine Group. Mr. McWatters is President of Harry McWatters Inc., Vintage Consulting Group Inc., Okanagan Wine Academy and Black Sage Vineyards Ltd. He was appointed Chair of the Board of FortisBC Inc. in 2006. Mr. McWatters has been a Director of FortisBC Inc. since 2005 and a Director of Terasen Inc. since November 2007.

David G. Norris ** *Corporate Director, St. John's, NL*

Mr. Norris, 61, joined the Fortis Inc. Board in May 2005 and was appointed Chair of the Audit Committee of the Board in May 2006. He has been a financial and management consultant since 2001, prior to which he was Executive Vice-President, Finance and Business Development, Fishery Products International Limited. Previously, he held Deputy Minister positions with Department of Finance and Treasury Board, Government of Newfoundland and Labrador. Mr. Norris was appointed Chair of the Board of Newfoundland Power Inc. in 2006. He has been a Director of Newfoundland Power Inc. since 2003 and a Director of Fortis Properties Corporation since 2006.

Michael A. Pavey * *Corporate Director, Moncton, NB*

Mr. Pavey, 61, joined the Fortis Inc. Board in May 2004. He retired as Executive Vice-President and Chief Financial Officer of Major Drilling Group International Inc. in 2006. Prior to joining Major Drilling in 1999, he held senior executive positions with a major integrated electric utility in western Canada. Mr. Pavey was previously a Director of Maritime Electric Company, Limited.

Roy P. Rideout ** *Corporate Director, Halifax, NS*

Mr. Rideout, 61, joined the Fortis Inc. Board in March 2001 and is Chair of the Human Resources Committee of the Board. He retired as Chairman and CEO of Clarke Inc. in October 2002. Prior to 1998, Mr. Rideout served as President of Newfoundland Capital Corporation Limited and held senior executive positions in the Canadian airline industry. He also serves as a Director of the Halifax International Airport Authority and NAV CANADA.

* Audit Committee

** Governance and Nominating Committee

* Human Resources Committee

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Fortis Inc. Officers (l-r): Barry Perry, VP, Finance and CFO; Donna Hynes, Assistant Secretary and Manager, Investor and Public Relations; Stan Marshall, President and CEO; Ronald McCabe, VP, General Counsel and Corporate Secretary

Investor Information

Transfer Agent and Registrar

Computershare Trust Company of Canada ("Computershare") is responsible for the maintenance of shareholder records and the issue, transfer and cancellation of stock certificates. Transfers can be effected at its Halifax, Montreal and Toronto offices. Computershare also distributes dividends and shareholder communications. Inquiries with respect to these matters and corrections to shareholder information should be addressed to the Transfer Agent.

Computershare Trust Company of Canada

9th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
T: 514.982.7555 or 1.866.586.7638
F: 416.263.9394 or 1.888.453.0330
W: www.computershare.com/fortisinc

Direct Deposit of Dividends

Shareholders may obtain automatic electronic deposit of dividends to their designated Canadian financial institutions by contacting the Transfer Agent.

Duplicate Annual Reports

While every effort is made to avoid duplications, some shareholders may receive extra reports as a result of multiple share registrations. Shareholders wishing to consolidate these accounts should contact the Transfer Agent.

Eligible Dividend Designation

For purposes of the enhanced dividend tax credit rules contained in the *Income Tax Act* (Canada) and any corresponding provincial and territorial tax legislation, all dividends paid on common and preferred shares after December 31, 2005 by Fortis to Canadian residents are designated as "eligible dividends." Unless stated otherwise, all dividends paid by Fortis hereafter are designated as "eligible dividends" for the purposes of such rules.

Expected Dividend* and Earnings Dates

Dividend Record Dates

May 8, 2009	August 7, 2009
November 6, 2009	February 5, 2010

Dividend Payment Dates

June 1, 2009	September 1, 2009
December 1, 2009	March 1, 2010

Earnings Release Dates

April 30, 2009	August 5, 2009
November 5, 2009	February 4, 2010

* The declaration and payment of dividends are subject to the Board of Directors' approval.

Dividend Reinvestment Plan and Consumer Share Purchase Plan

Fortis Inc. offers a Dividend Reinvestment Plan ("DRIP")⁽¹⁾ and a Consumer Share Purchase Plan ("CSPP")⁽²⁾ to Common Shareholders as a convenient method of increasing their investments in Fortis Inc. Participants have dividends plus any optional contributions (DRIP: minimum of \$100, maximum of \$30,000 annually; CSPP: minimum of \$25, maximum of \$20,000 annually) automatically deposited in the Plans to purchase additional Common Shares. Shares can be purchased quarterly on March 1, June 1, September 1 and December 1 at the average market price then prevailing on the Toronto Stock Exchange. Inquiries should be directed to the Transfer Agent.

(1) All registered holders of Common Shares who are residents of Canada are eligible to participate in the DRIP. Shareholders residing outside Canada may also participate unless participation is not allowed in that jurisdiction. Residents of the United States, its territories or possessions are not eligible to participate.

(2) The CSPP is offered to residents of the provinces of Newfoundland and Labrador and Prince Edward Island.

Share Listings

The Common Shares; First Preference Shares, Series C; First Preference Shares, Series E; First Preference Shares, Series F; and First Preference Shares, Series G of Fortis Inc. are listed on the Toronto Stock Exchange and trade under the ticker symbols FTS, FTS.PR.C, FTS.PR.E, FTS.PR.F and FTS.PR.G, respectively.

Valuation Day

For capital gains purposes, the valuation day prices are as follows:

December 22, 1971	\$ 1.531
February 22, 1994	\$ 7.156

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Annual Meeting

Tuesday, May 5, 2009
10:30 a.m.
Holiday Inn St. John's
180 Portugal Cove Road
St. John's, NL Canada

Printer:

The Lowe-Martin Group,
Ottawa, ON

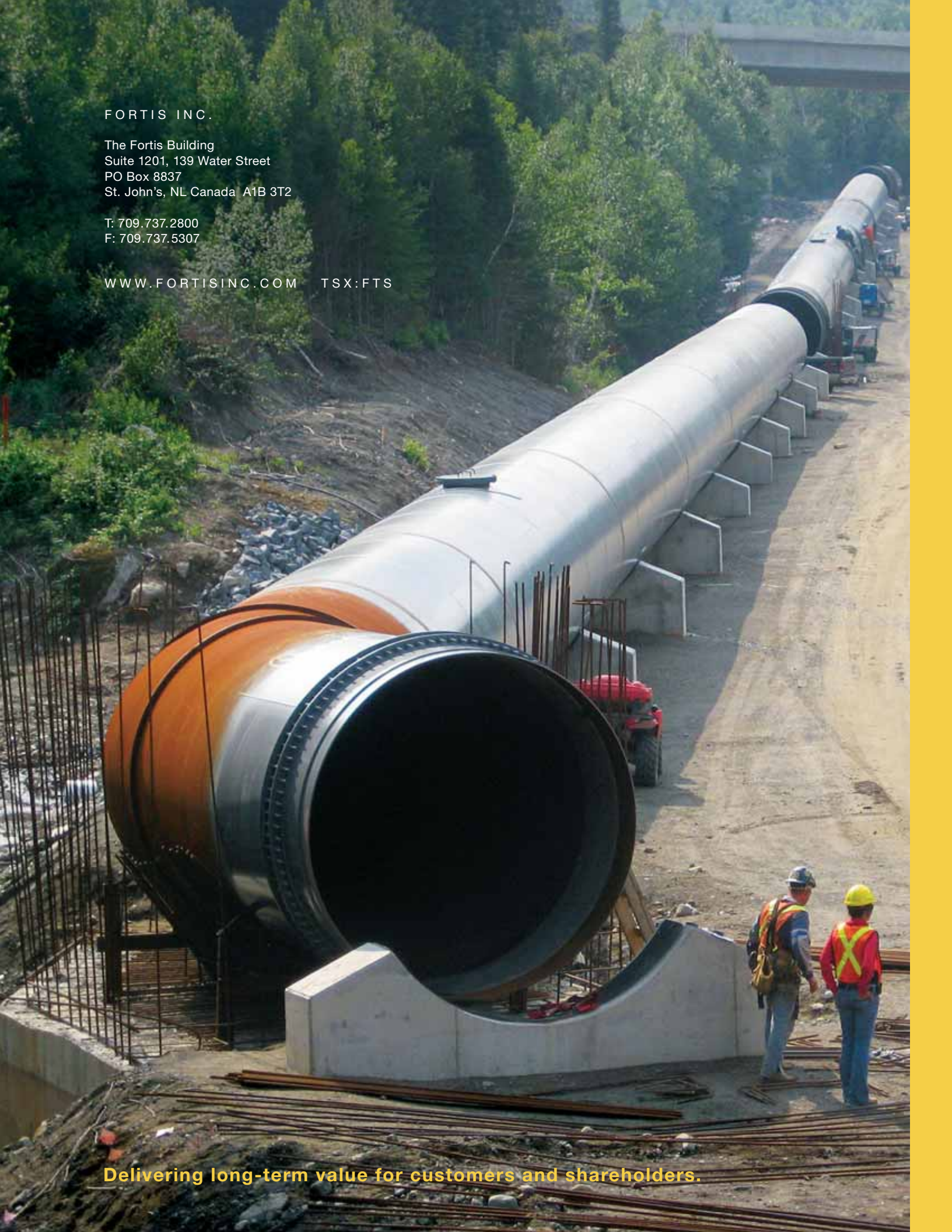
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Delivering long-term value for customers and shareholders.



Appendix H

Brookfield Asset Management

2007 Annual Report



Profile and Investment Principles

Brookfield is a global asset manager. Focused on property, power and infrastructure assets, the company has approximately \$95 billion of assets under management and is co-listed on the New York, Toronto and Euronext stock exchanges under the symbol BAM.

BUSINESS PHILOSOPHY

- Build the business based on honesty and integrity in order to enhance our reputation
 - Attract and retain high calibre individuals who will grow with us over the long term
 - Ensure our people think and act like owners in all their decisions
 - Treat our clients' money like it is our own
-

INVESTMENT GUIDELINES

- Invest where we possess competitive advantages
 - Acquire assets on a value basis with a goal of maximizing return on capital
 - Build sustainable cash flows to provide certainty, reduce risk and lower the cost of capital
 - Recognize that superior returns often require contrarian thinking
-

MEASUREMENT OF OUR CORPORATE SUCCESS

- Measure success over the long term by total return on capital
 - Encourage calculated risks, but compare returns with risk
 - Sacrifice short-term profit, if necessary, to achieve long-term capital appreciation
 - Seek profitability rather than growth, because size does not necessarily add value
-

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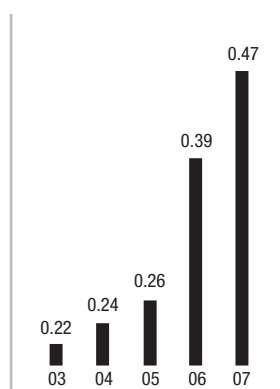
Financial Highlights

AS AT AND FOR THE YEARS ENDED DECEMBER 31

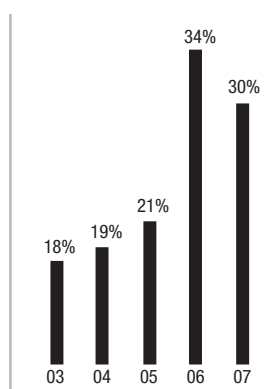
(MILLIONS, EXCEPT PER SHARE AMOUNTS)

	2007	2006	2005
Per fully diluted common share			
Cash flow from operations	\$ 3.11	\$ 2.95	\$ 1.46
Cash return on equity	30%	34%	21%
Market trading price – NYSE	\$ 35.67	\$ 32.12	\$ 22.37
Net income	\$ 1.24	\$ 1.90	\$ 2.72
Dividends paid	\$ 0.47	\$ 0.39	\$ 0.26
Total			
Assets under management	\$ 94,340	\$ 71,121	\$ 49,700
Consolidated balance sheet assets	\$ 55,597	\$ 40,708	\$ 26,058
Revenues	\$ 9,343	\$ 6,897	\$ 5,220
Operating income	\$ 4,509	\$ 3,776	\$ 2,319
Cash flow from operations	\$ 1,907	\$ 1,801	\$ 908
Net income	\$ 787	\$ 1,170	\$ 1,662
Diluted number of common shares outstanding	611	611	608

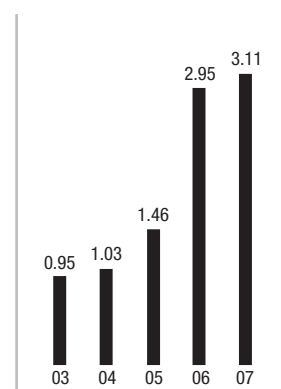
Dividends Per Common Share
in dollars



Return on Equity
percentage



Cash Flow Per Share
in dollars



A Global Asset Manager



We are a long-term, value-oriented investor with approximately \$95 billion of assets under management.

Our primary objective is to own and manage investment funds that generate attractive long-term returns through the direct and indirect ownership of assets producing sustainable cash flows in our areas of expertise – property, power, infrastructure and specialty funds.

With over 100 years of experience investing and operating these high quality assets globally, we are uniquely positioned to offer specialty investment products to our clients.



**Market
Capitalization***

\$20 billion

**Assets Under
Management**

\$95 billion

**Stock Exchange
Listings**

NYSE, TSX, Euronext

**Employees in the Americas,
Europe and Australasia**

Over 10,000

* As at December 31, 2007

Letter to Shareholders

OVERVIEW

In 2007, we recorded our highest ever cash flow from operations of \$1.9 billion or \$3.11 per share. This represented only a slight increase over 2006 given the special gains we recorded that year but is more than double our results in 2005. This cash flow growth was due to increased assets under management, solid performance from most of our operations, and some realization items. Net income was approximately \$800 million and while not as relevant a measure for our business because it includes depreciation, was nonetheless one of the highest in the company's history.

Higher cash flows and increased assets under management translated into an increase in the intrinsic value of our business overall, with a few notable but thankfully small exceptions. Our share price in the market increased by 11% over the year. Including dividends, the total return for 2007 was 12%, although that market gain has been erased since the beginning of January given the general malaise in the financial markets.

Our shares underperformed their five and 10 years' averages in the stock market, but given the negative performances of asset managers, property related companies and financial entities we at least held our own.

Annualized Returns	Brookfield — NYSE	S&P	TSX
YEARS			
1	12%	6%	10%
5	46%	13%	18%
10	25%	6%	10%
20	16%	12%	10%

In 2007, we achieved many of our goals and missed a few. Most importantly, our funds continue to record strong investment results and we have expanded our operating platform around the globe. We now have a physical presence in most of the world's major markets.

We increased gross assets under management by \$25 billion, enhanced our fundraising capabilities, expanded the business into Australia, the Middle East and Asia, invested approximately \$10 billion of capital and are in the midst of fundraising for a number of new funds within our areas of expertise. Notable additions to our assets under management were the purchase of \$7 billion of property assets in Australia and New Zealand, \$1 billion of retail shopping centres in Brazil and approximately \$2 billion of timber and agricultural lands. We also added \$6 billion of real estate equities and fixed income advisory mandates, largely through the acquisition of a specialty investment management firm, which we intend to further expand globally and into new infrastructure product offerings.

Looking to 2008, we believe we are well positioned to continue building our business in the current environment. We have significant capital available, a healthy balance sheet and a performance culture where operating management teams can find a home as long-term owners and operators of their businesses. We believe these three items provide us with a strategic advantage over many other global asset managers, and should bode well for us in 2008 and 2009.

MARKET ENVIRONMENT

For almost 20 years, we have witnessed a period of unprecedented world economic growth and prosperity interrupted only briefly by periods of mild recession. This incredible period of growth has been fueled by globalization, the collapse of communist protectionism, huge productivity gains made possible by technology, and the secular decline of inflation and long-term interest rates, among other factors.

But as with everything, pressures and stresses eventually build up. Over the past few years, most of these remained below the surface. However, since the summer of 2007 they have now come into plain view. The first signs showed up in the debt

markets, which by mid 2007 had become extremely robust. Today, credit spreads have widened dramatically as global banks struggle to clear their unsold inventory of transactions and deal with residential mortgage securities created in the prior environment. What began as a bank issue, is now beginning to affect homeowners, consumers and industry in general.

Time will tell how all of this plays out. That said, the powerful forces that started this period of positive growth largely remain in place. This provides us with many reasons to remain optimistic over the longer term. Nonetheless, we remain cautious in these uncertain times and have taken a number of actions and measures over the past six months to help manage our risks in this changing environment. Specifically, we:

- raised capital wherever possible and extended the duration of debt. In particular, we sold assets which were not core to our long-term business;
- ensured that our investment teams did not commit to any significant investment opportunities without committed financing in place;
- reduced the risk of short-term financial assets that we hold, through outright sale, or other means; and,
- purchased credit protection on a portfolio of approximately \$2 billion notional of corporate debt as a hedge against the rising cost of debt due to a widening in credit spreads. To date, this credit protection has generated realized and unrealized gains in excess of \$100 million, some of which were accounted for in the results in 2007.

Fortunately, we have entered 2008 in a strong financial position. We also believe the current volatile environment favours long-term owners and operators of assets. Our balance sheet strength and our long-term investment horizon should, as a result, play to our advantage as other owners of assets wishing to sell begin to place greater importance on certainty

of closing. And, as we typically finance our investments with significant equity, often comprising up to 50% of the purchase price, and finance the balance with fixed-rate, long-term investment grade financing, we are not as affected as many of our competitors who rely on the more volatile high-yield debt markets to finance their acquisitions.

With credit costs and terms tighter, much of the drive behind the recent leveraged buyout environment has dissipated. With these factors no longer driving prices, we are more likely to attain our long-term return on investment goals going forward. In the context of these forward-looking views, we believe there will be great opportunities to put investment capital to work in our areas of focus in order to generate greater-than-average returns over the longer term.

And despite the possibility of a U.S. recession, we believe in the resilience of the U.S. economy, and the dramatic impact that the integration of the developing world is having on world GDP growth. These facts favour a positive investment environment once this adjustment process has run its course.

GOALS AND STRATEGY

As stated before, our long-term goal is to achieve a compound 12% annual growth in the cash flows from operations on a per-share value. This should lead to a total underlying value increase on a per-share basis of greater than 12%. This return will not occur consistently each year, but we believe we can achieve this objective over the longer term by continuing to focus on four key operating strategies:

- Build a world-class asset management firm for institutional and retail investors, offering a focused group of products on a global basis to our clients.
- Differentiate our product offerings by utilizing our decades of investment and operating experience and our long-term investment horizons, allowing us to have a different, longer-

term perspective in acquisitions and building operations, thereby enabling us to generate greater returns over the long term for our partners.

- Focus our products on simple to understand, high quality, long-life, cash-generating physical assets that require minimal sustaining capital expenditures and have some form of barrier to entry, a characteristic which should lead to appreciation in the value of these assets over time.
- Maximize the value of our operations by actively managing our assets to create operating efficiencies, lower our cost of capital and enhance cash flows. Given that our assets generally require high initial capital investment, have relatively low variable cost, and can be leveraged on a long-term, low-risk basis, even a small increase in the top-line performance typically results in a much more meaningful contribution to the bottom line.

We believe we can continue to successfully grow our global asset management business, because underlying fundamentals for asset management, particularly within the infrastructure space, continue to be positive. In fact, in an uncertain world, we believe our lower-risk, lower-volatility products should become even more appealing, especially as investors reprice risk in the marketplace.

Changes in both demand and supply continue to drive the fundamentals of our business. With respect to demand for our products, institutional pools of capital across the world now total in excess of \$20 trillion. As allocations by these investors to our type of products increase, we believe the demand for our product offerings will continue to grow at a rapid pace.

At the same time, the required investment in infrastructure assets is estimated at several trillion dollars annually in order to provide proper infrastructure in emerging economies, ensure appropriate upkeep of infrastructure in currently developed markets, and support further global expansion. We need only

to participate in a very small way to fulfill our plans over the next ten years.

GLOBAL OPERATING PLATFORM

For many decades we have owned and operated the type of assets we now buy in conjunction with our asset management clients. We believe this differentiation, with hands-on operators in all of our businesses, has and will continue to enable us to outperform investors who do not have these capabilities.

In order to service our highly sophisticated group of investors, we have continued to invest in our existing operating platforms in property, renewable power, timber and transmission. We have also been developing operating platforms to support other emerging forms of infrastructure, and globalized the business because many institutions are increasingly looking for an investment manager with a global product offering, providing reliable one-stop shopping.

Over the past five years we have increased our staff to over 10,000, which includes 300 investment professionals. We have enhanced our presence in North and South America, built upon our business in Europe, added a meaningful presence in Australia, and established bases in Dubai, Hong Kong and China. We believe this corporate investment will pay off for you and for our co-investors as we increase the size of many of our fund offerings in the next few years.

CURRENCIES

The increasingly global nature of our operating platforms has had the effect of increasing the foreign content of our business. To date, because of the decline of the U.S. dollar, this internationalization has added value to the company, compared to having only been invested in the U.S.

We report our results in U.S. dollars and, from a currency perspective, changes in the value of the U.S. dollar relative to

other currencies will impact the operating results and values of our non-U.S. activities. Often we hedge our non-U.S. operations with local debt, but typically the equity and increases in value are not hedged. We estimate that currently approximately 50% of our market capitalization is represented by U.S. dollars and the balance of 50% is invested internationally. The largest international investments are in Canada and Australia, with the next largest in Brazil and the UK.

The decline of the U.S. dollar against world currencies in 2007 had a positive impact on the intrinsic values and cash flow producing ability (in U.S. dollars) of our non-U.S. assets. A 10% movement in the U.S. dollar against our other currencies results in a change in the value of approximately \$2.00 per share. These numbers are merely indicative, and the exact calculations will change quarterly. And, while we don't try to take currency positions, we are an international investor, and therefore our returns are inevitably affected by currency movements across the world.

MARKETING OF FUNDS

During 2007, we added approximately \$10 billion of managed capital to our operations and are currently in the market with a number of private funds where we hope to raise several billions more. Most of this capital will come from global institutional investors, and in order to accommodate the increased demands on our resources, we have continued to expand our capabilities, both to market these funds and to better service these institutions.

In addition to private funds, we also sponsor specialty public issuers that enable public market investors to participate directly in our investment strategies. The first major initiative in this regard was the creation of NYSE-listed Brookfield Infrastructure Partners. By now you should have each received your units of this new entity by way of a special dividend. As articulated before, we intend to utilize Brookfield Infrastructure

as our primary growth vehicle for the purchase of certain infrastructure assets in the future. We hope that Brookfield Infrastructure will appeal to those investors seeking higher yield and lower volatility than traditional equity investments.

Our long-term goal is to substantially expand our assets under management, ultimately ending up with our commitment to each strategy at less than 20%. As a result, and given the scale of capital which we have in the business today, we should be able to substantially grow our assets under management with the capital we have in the business.

INVESTMENT RETURNS AND FINANCIAL REPORTING

As stated in our second quarter report to you, we are often asked about the overall make-up of our cash flow from operations, and in particular, whether we focus on current cash flows or cash flows on a total-return basis. The short answer is that we focus on both, but predominantly on total return.

To date, for simplicity purposes, we have focused our reporting to you on the cash flows generated on an ongoing basis from our operations and realization gains as they occur. Given our continued focus on total-return investing, this is an important concept to understand and worth exploring in further detail.

On average, we invest capital seeking at least a 12% to 15% leveraged return. We assess returns on a total basis – meaning that we include the present values of cash flows received over the life of our investment as well as the “terminal value,” which represents the value of the investment at a future point in time. This is commonly referred to as an internal rate of return, or “IRR”.

As you know, we focus on assets that we believe will generate increasing levels of cash flow over time, and that appreciate in value. In many cases, the current cash return from an investment at inception may be well below the targeted IRR. This means that for accounting purposes, the returns that are

reflected in our financial results are typically significantly below our internal rate of return in the early years of our ownership. Over time, as the cash flows increase, higher returns will be reflected in our reported results.

What is usually not reflected in our financial results are increases in the values of our investments over the amount of the original invested capital. The values of assets such as ours typically increase by an amount equal to the capitalized value of the increase in the associated cash flows. This appreciation in value is generally not reflected in our financial results until such time as we sell the asset, at which point we will record a realization gain. However, we are generally inclined to hold assets indefinitely, preferring to monetize the accrued value by refinancing the asset as opposed to an outright sale. This has the added benefit of deferring any accrued tax liability but, in the absence of a crystallization event, the accrued value may never appear in our reported financial results.

The implications of this analysis are twofold. The first is that the cash flows reported on a meaningful amount of our capital are not, in our view, representative of the total return that we expect to receive over the life of the investment. This is particularly so for newer investments, development initiatives, and securities investments. The second implication is that realization gains, when they do occur, form an important part of our total returns and typically represent only a small portion of the overall increase in intrinsic value that is built each year within our operations.

SUMMARY

We remain committed to building a world-class asset manager, and investing capital for you and our co-investment partners in high quality, simple to understand assets which earn a solid cash-on-cash return on equity, while always emphasizing downside protection of the capital employed.

The primary objective of the company continues to be generating increased cash flows, and as a result, higher intrinsic value on a per-share basis over the longer term.

It is always important to remind ourselves that there may be occasional periods of time, maybe years, when the market value of any company, for various reasons, may not equate to the intrinsic value of the business. This fact often presents us opportunities to acquire assets in the public market at less than intrinsic value, but can similarly affect your shareholdings in our company for periods of time. Given the “bearishness” that exists in the capital markets today, this is probably more important to note than usual.

And, while I personally sign this letter, I respectfully do so on behalf of all of the members of the Brookfield team, who collectively generate the results for you. Please don’t hesitate to contact any of us, should you have suggestions, questions, comments, or investment ideas.



J. Bruce Flatt
Managing Partner
February 7, 2008

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report to Shareholders contains forward-looking information within the meaning of Canadian provincial securities laws and other “forward-looking statements”, within the meaning of certain securities laws including Section 27A of the U.S. Securities Act of 1933, as amended, Section 21E of the U.S. Securities Exchange Act of 1934, as amended, “safe harbor” provisions of the United States Private Securities Litigation Reform Act of 1995 and in any applicable Canadian securities regulations. We may make such statements in this report, in other filings with Canadian regulators or the SEC or in other communications. These forward-looking statements include among others, statements with respect to our financial and operating objectives and strategies to achieve those objectives, capital committed to our funds, the potential growth of our asset management business and the related revenue streams therefrom, statements with respect to the prospects for increasing our cash flow from or continued achievement of targeted returns on our investments, as well as the outlook for the company’s businesses and for the Canadian, United States and global economies and other statements with respect to our beliefs, outlooks, plans, expectations, and intentions.

The words “believe”, “typically”, “expect”, “think”, “potentially”, “encouraging”, “principally”, “tend”, “primarily”, “generally”, “represent”, “anticipate”, “position”, “intend”, “estimate”, “encouraging”, “expanding”, “scheduled”, “should”, “endeavour”, “promising”, “seeking”, “often” and other expressions of similar import, or the negative variations thereof, and similar expressions of future or conditional verbs such as “may”, “will”, “should”, “likely”, “would” or “could” are predictions of or indicate future events, trends or prospects and which do not relate to historical matters or identify forward-looking statements. Although Brookfield Asset Management believes that the anticipated future results, performance or achievements expressed or implied by the forward-looking statements and information are based upon reasonable assumptions and expectations, the reader should not place undue reliance on forward-looking statements and information because they involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the company to differ materially from anticipated future results, performance or achievement expressed or implied by such forward-looking statements and information.

Factors that could cause actual results to differ materially from those contemplated or implied by forward-looking statements include: economic and financial conditions in the countries in which we do business; the behaviour of financial markets, including fluctuations in interest and exchange rates; availability of equity and debt financing; strategic actions including dispositions; the ability to effectively integrate acquisitions into existing operations and the ability to attain expected benefits; the company’s continued ability to attract institutional partners to its Specialty Investment Funds; adverse hydrology conditions; regulatory and political factors within the countries in which the company operates; acts of God, such as earthquakes and hurricanes; the possible impact of international conflicts and other developments including terrorist acts; and other risks and factors detailed from time to time in the company’s form 40-F filed with the Securities and Exchange Commission as well as other documents filed by the company with the securities regulators in Canada and the United States including in the Annual Information Form under the heading “Business Environment and Risks”.

We caution that the foregoing list of important factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Brookfield Asset Management, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Except as may be required by law, the company undertakes no obligation to publicly update or revise any forward-looking statements or information, whether written or oral, that may be as a result of new information, future events or otherwise.

CAUTIONARY STATEMENT REGARDING USE OF NON-GAAP ACCOUNTING MEASURES

This Annual Report and accompanying consolidated financial statements make reference to cash flow from operations on a total and per share basis. Management uses cash flow from operations as a key measure to evaluate performance and to determine the underlying value of its businesses. The consolidated statements of cash flow from operations provides a full reconciliation between this measure and net income. Readers are encouraged to consider both measures in assessing Brookfield’s results.

Management's Discussion and Analysis of Financial Results

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PART 1 – INTRODUCTION

The information in this Management Discussion and Analysis of Financial Results ("MD&A") should be read in conjunction with our audited consolidated financial statements, which are included on pages 83 through 115 of this report. Additional information, including the company's Annual Information Form, is available on the Corporation's web site at www.brookfield.com and on SEDAR's web site at www.sedar.com. For additional information on each of the five most recently completed financial years, please refer to the table on page 116 of this report.

BUSINESS OVERVIEW

Brookfield is a global asset management company, with a primary focus on property, power and infrastructure assets. We have established leading operating platforms in these sectors and, through them, own and manage a broad portfolio of high quality assets that generate long-term cash flows and opportunities for value creation for us and our clients. We create value for our shareholders by increasing, over time, the cash flows generated by managing these assets for our clients as well as from the capital that we have invested alongside our clients.

BASIS OF PRESENTATION

We have organized the MD&A on a basis that is consistent with how we operate the business. We organize our activities into a Corporate Group and individual Operating Platforms which focus on a specific business segment. These platforms include commercial properties, power generation, infrastructure, development and other properties, specialty funds and advisory services.

We make a distinction within our operating platforms between Asset Management and Operations. We characterize Asset Management as including, among other things: strategic oversight, investment analysis, capital allocation and advisory and other specialized services such as investment banking, facilities management and property leasing. Operations represent the balance of activities directly associated with the underlying businesses. Accordingly, we segregate our financial results between Asset Management and Operations. We also segregate our financial results and our assets, liabilities and capital by Operating Platform.

In reporting our asset management activities, we recognize not only the results of the asset management activities that we perform on behalf of our clients, but also in respect of our own capital. We do this in order to present our results and margins on a consistent

and more meaningful basis. For capital invested by us in established funds, we report the related fees on the same terms as our clients. For the balance of our capital that is invested directly in similar assets, we attribute cash flows by applying a percentage fee to the estimated value of the operations. While this attribution is currently an internal allocation, we intend to provide co-investors the opportunity to participate in many of these assets over time, which will replace this attribution with cash flows from third parties and provide us with additional capital to expand our operating platforms in the process.

We use operating cash flow as a key measure of our financial performance. This is a non-GAAP measure and differs from net income, and may differ from definitions of operating cash flow used by other companies. We define operating cash flow as net income prior to such items as depreciation and amortization, future income tax expense and certain non-cash items that in our view are not reflective of the underlying operations.

We present invested capital and operating cash flows on a “total” basis, which is similar to our consolidated financial statements and a “net” basis. Net invested capital and net operating cash flows represent our pro rata interest in the underlying net assets and cash flows. They are, with the exception of the operations of Brookfield Properties Corporation, presented on a deconsolidated basis meaning that assets are presented net of associated liabilities and non-controlling interests. Similarly, cash flows are represented net of carrying charges associated with related liabilities and cash flow attributable to related non-controlling interests. Net invested capital and net operating cash flows, in our view, represent a more consistently comparable basis of presentation than our consolidated financial statements which include our operations under various methods, including equity accounting, proportional consolidation and full consolidation.

We provide reconciliations between this basis of presentation in the MD&A and our consolidated financial statements. In particular, we reconcile operating cash flow and net income on page 30. The tables on pages 72 and 73 provide a reconciliation between our consolidated financial statements and basis of presentation used herein.

Unless the context indicates otherwise, references in this MD&A to the “Corporation” refer to Brookfield Asset Management Inc., and references to “Brookfield” or “the company” refer to the Corporation and its direct and indirect subsidiaries and consolidated entities. All financial data included in the MD&A has been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) and specified non-GAAP measures unless otherwise noted. All figures are presented in U.S. dollars, unless otherwise noted.



Brian D. Lawson
Managing Partner and Chief Financial Officer

February 7, 2008



Sachin G. Shah
Senior Vice President, Finance

PART 2 – PERFORMANCE REVIEW

SUMMARY

In this section we review our performance during 2007, our financial position at year end and our outlook for 2008. Further details on our operations and financial position are contained within Part 5 – Description of Operating Platforms beginning on page 48.

Operating cash flow totalled \$1.9 billion for the year compared with \$1.8 billion in 2006 and \$0.9 billion in 2005. This represents an increase of 6% over 2006 and is more than double the cash flows reported in 2005. Excluding the impact of realization gains, operating cash flows increased by 46% over the comparable 2006 results.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS, EXCEPT PER SHARE AMOUNTS)	2007	2006	2005
Operating cash flow			
– total	\$ 1,907	\$ 1,801	\$ 908
– per share ¹	3.11	2.95	1.46
– prior to realization gains	1,736	1,191	908

¹ Adjust to reflect three-for-two stock split

We continued to make progress in expanding our asset management activities and associated income through the acquisition of additional assets and expansion into new geographic regions. This has resulted in increases in both assets and capital under management, a higher level of annualized base fee revenues and increases in the amount of accumulated performance returns such as performance fees, carried interest participations and incentive distributions. We recorded improved results across most of our operating platforms, particularly in our property and specialty fund groups, which generated strong investment returns for ourselves and our clients. We also experienced strong performance within our private equity and financial asset portfolios, which more than offset the impact of lower water levels on our power generation facilities as well as the impact of weakness in the U.S. housing markets. The increase in 2006 operating cash flow from the 2005 results reflected a higher level of realization gains, expansion of our operating platform through acquisitions and the impact of above average water flows on our power generation business.

Realization gains contributed \$171 million during 2007 compared with \$610 million in 2006. Realization gains are gains or losses that arise on transactions involving long-term assets and liabilities, such as a disposition or change in ownership. We do not include gains or losses that relate to shorter-term items such as financial assets or assets held in opportunity or restructuring funds, because these are a regular part of ongoing activities. The timing of realization gains is, due to their nature, difficult to predict, however, they do reflect a portion of the increase in the underlying value of our operations and represent an important part of our long-term returns.

The following table presents net income for the past three years determined in accordance with Canadian GAAP. We do not utilize net income as a key metric in assessing the performance of our business because, in our view, it contains measures that may distort the ongoing performance and intrinsic value of the underlying operations. Nevertheless we recognize the importance of net income as a key measure for many users and provide a full discussion of our net income and a reconciliation to operating cash flow.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS, EXCEPT PER SHARE AMOUNTS)	2007	2006	2005
Net income			
– total	\$ 787	\$ 1,170	\$ 1,662
– per share ¹	1.24	1.90	2.72
– prior to realization gains and accounting change	941	624	562

¹ Adjust to reflect three-for-two stock split

Net income prior to realization gains and a change in accounting policy was \$941 million compared with \$624 million last year and \$562 million in 2005. The increase in each of 2007 and 2006 over prior years reflects increases in operating cash flow noted above, offset by depreciation on recently acquired assets. We reconcile net income to operating cash flow on page 30.

Realization gains included in net income totalled \$177 million in 2007, representing the \$171 million of net gains included in operating cash flows as noted above and a \$6 million recovery of non-cash accounting tax provisions net of minority interests. Realization gains included in net income during 2006 totalled \$546 million, and differs from the \$610 million of gains included in operating cash flow due to non-cash tax provisions net of minority interest totalling \$64 million. Realization gains in 2005 represented an after-tax gain of \$1.1 billion on the sale of a large legacy investment.

The change in accounting policy resulted in an accrued gain of \$331 million on an investment sold during the year being recorded directly in opening retained earnings as opposed to net income due to prescribed changes in accounting guidelines.

We measure our performance against two specific criteria which are set out in the following table together with our annual performance over the past five years:

FOR THE YEARS ENDED DECEMBER 31	Long-term Objective	Five-Year Results	Annual Results				
			2007	2006	2005	2004	2003
Operating cash flow and gains per share ¹			\$ 3.11	\$ 2.95	\$ 1.46	\$ 1.03	\$ 0.95
Annual growth	12%	35%	5%	102%	41%	8%	35%
Cash return on book equity per share	20%	25%	30%	34%	21%	19%	18%

¹ Adjust to reflect three-for-two stock split

Annual cash flow growth in 2007 was below our long-term objective, however this is largely due to the particularly strong results and higher level of realization gains recorded in 2006. Annualized growth over the last five years was 35%. We achieved a 30% cash return on equity during 2007 and a 25% average return over the past five years.

The results for the five years ending in 2007 and the year ended 2006, respectively, exceed our long-term expectations. Accordingly, shareholders should not expect us to generate this rate of growth on an ongoing basis.

Segmented Operating Results

The following table distinguishes our operating cash flows between the operating returns on our invested capital and the returns from our asset management activities:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007			2006		
	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
Operating platforms	\$ 695	\$ 1,479	\$ 2,174	\$ 483	\$ 1,165	\$ 1,648
Cash and financial assets	—	695	695	—	396	396
Realization gains	—	158	158	—	610	610
	695	2,332	3,027	483	2,171	2,654
Unallocated costs	(264)	(488)	(752)	(192)	(414)	(606)
	431	1,844	2,275	291	1,757	2,048
Co-investor interests	(65)	(303)	(368)	(54)	(193)	(247)
	\$ 366	\$ 1,541	\$ 1,907	\$ 237	\$ 1,564	\$ 1,801

Our asset management activities generated \$366 million of operating cash flow during 2007 compared with \$237 million during 2006. These results include base management fees and performance returns from existing funds, as well as fees attributed to assets that we manage on our own behalf that are not yet held through funds. The increase is due to a higher level of capital deployed compared to 2006.

Our operating platforms contributed \$1.5 billion of operating cash flow prior to realization gains and unallocated costs, representing an increase of 27% over 2006, due to continued growth and strong performance in a number of our operations. These results are net of fees charged in respect of asset management activities. We discuss these results in greater detail in the Operating Platforms Section beginning on page 16.

Investment income generated from our financial assets and other activities increased to \$695 million reflecting a higher level of investment gains over the prior year. Realization gains were significantly higher in 2006, more than offsetting the positive variance in investment income, as we realized gains on the monetizations of a number of our long-term assets during that year in the process of establishing new funds and other activities.

The increase in unallocated costs reflects the expansion in our operating platforms as well as an increased level of activity devoted to the development of new operating platforms and the expansion of our asset management capabilities, as well as a modest increase in interest costs.

Co-investor interests are comprised principally of the cash flows attributable to minority shareholders of Brookfield Properties Corporation as all other cash flows are shown net of the associated co-investor interests as explained under Basis of Presentation.

Overview of Asset Management Results

The following table summarizes asset management income and fees generated for the past two years. “Total” represents fee income generated by the assets and capital under management on a 100% basis, including amounts attributed to the capital we have invested in established funds with co-investors as well as assets that are held directly by Brookfield, whereas “Third Party” amounts represent only amounts earned by us from assets and capital managed on behalf of clients (i.e. it excludes operating cash flow generated on our own capital, which is eliminated in preparing our financial statements in accordance with GAAP).

The following table sets out the key components of revenues from core asset management activities:

	<i>Total</i>		<i>Third Party</i>	
	<i>2007</i>	<i>2006</i>	<i>2007</i>	<i>2006</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>				
Base management fees	\$ 349	\$ 290	\$ 104	\$ 68
Performance returns	12	5	8	3
Transaction fees	116	33	103	31
Property services	184	139	166	139
Investment banking	34	16	34	16
	695	483	415	257
Direct operating costs	(264)	(192)	—	—
Co-investor interests in consolidated operations	(65)	(54)	—	—
	\$ 366	\$ 237	\$ 415	\$ 257

Base management fees are a key measure in assessing the growth of our business. They increased during 2007 as a result of new funds and increases in the amount of capital under management. As at December 31, 2007, annualized base management fees on existing funds and assets under management totalled \$160 million (2006 – \$100 million), of which \$120 million (2006 – \$75 million) relates to client capital.

Base management fees include the fees of \$104 million (2006 – \$68 million) earned from third-party clients, \$33 million (2006 – \$13 million) from the capital that we have invested in existing funds and \$212 million (2006 – \$209 million) attributed to assets that are not held in existing funds.

Transaction fees include a substantial fee earned in the first quarter of 2007 in connection with our efforts to establish a North American retail property platform and an associated capital commitment. Transaction fees also include investment fees earned in respect of financing activities and include commitment fees, work fees and exit fees.

Property services fees include property and facilities management, leasing and project management and a range of real estate services. The increase reflects a higher level of activity within our facilities management operations. We provide specialized investment banking services in North America and Brazil. These groups increased fees during the year through the expansion of their operating base and by concluding a number of successful mandates.

The level of performance returns recorded in our results continues to be modest because they tend to materialize later in the life cycle of a fund and because we have elected to follow accounting guidelines that defer recognition in our financial statements. The following table includes performance returns on established funds that we believe have accumulated during the year, but are not included in our reported results. As our funds mature, we expect to be able to recognize an increasing portion of these accumulated fees.

	<i>Total</i>		<i>Third Party</i>	
	<i>2007</i>	<i>2006</i>	<i>2007</i>	<i>2006</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>				
Net performance returns accumulated during the year	\$ 272	\$ 100	\$ 92	\$ 57
Less: returns reported in financial results	(12)	(5)	(8)	(3)
Unrecognized performance returns accumulated during the year	\$ 260	\$ 95	\$ 84	\$ 54

The increase in third-party accumulated performance returns, net of direct expenses, that has not been reflected in operating cash flows represents \$0.14 per share and \$0.09 per share, respectively, during each of 2007 and 2006.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Total		Third Party	
	2007	2006	2007	2006
Accumulated returns, beginning of year	\$ 95	\$ —	\$ 54	\$ —
Accumulated during the year	260	95	84	54
Total accumulated performance returns	\$ 355	\$ 95	\$ 138	\$ 54

We estimate that approximately \$29 million of direct expenses will arise on the realization of the returns that have accumulated to date (2006 – \$11 million). The average period of time over which these accumulated returns may be realized is six years, based on the terms of the relevant contracts. We expect that the ultimate receipt of these amounts will not result in any meaningful cash taxes.

Assets Under Management and Invested Capital

The following table presents the book values of total assets under management at the end of December 31, 2007 and December 31, 2006, including our interests and those of our co-investors, capital commitments by our co-investors, and Brookfield's invested capital measured in terms of consolidated assets and net invested capital.

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments ¹		Brookfield Invested Capital			
	2007	2006	2007	2006	Consolidated Assets		Net Invested	
	2007	2006	2007	2006	2007	2006	2007	2006
Operating platforms								
Commercial properties	\$ 30,750	\$ 21,114	\$ 2,898	\$ 2,317	\$ 25,315	\$ 17,231	\$ 4,803	\$ 3,773
Power generation	6,802	5,390	—	—	6,802	5,390	1,425	1,368
Infrastructure	6,755	4,333	1,192	1,171	4,435	4,333	1,645	864
Development and other properties	9,081	4,913	359	116	9,081	4,913	3,541	1,783
Specialty funds	7,487	7,867	3,547	2,118	2,736	1,797	1,137	1,182
Advisory services	26,237	20,460	26,237	20,460	—	—	—	—
	87,112	64,077	34,233	26,182	48,369	33,664	12,551	8,970
Private equity investments	3,851	3,450	—	—	3,851	3,450	1,336	1,404
Cash and financial assets	1,367	1,673	—	—	1,367	1,673	867	1,149
Other assets	2,010	1,921	—	—	2,010	1,921	2,010	1,921
	\$ 94,340	\$ 71,121	\$ 34,233	\$ 26,182	\$ 55,597	\$ 40,708	\$ 16,764	\$ 13,444

¹ Includes incremental co-investment capital

Assets under management and invested capital were impacted by three significant transactions during 2007. The acquisition of Multiplex increased total assets under management within our operating platforms by \$5.7 billion. This included \$2.5 billion of assets in property funds managed by the company and \$3.2 billion of directly held property assets. Our net invested capital in Multiplex, net of debt, is approximately \$2 billion.

We also acquired \$1.9 billion of private timberlands in the U.S. Pacific Northwest for a net investment of approximately \$670 million. This resulted in increased assets under management and net invested capital within our infrastructure operations. Consolidated infrastructure assets were relatively unchanged as the addition of the timberlands was offset when we commenced accounting for our Chilean transmission operations on an equity accounted basis.

Within our advisory group, assets under management and co-investor commitments both increased by approximately \$6 billion, largely from the acquisition of a Chicago-based real estate securities manager.

Finally, the increase in the value of the Canadian dollar, the British pound and the Brazilian *real* against the U.S. dollar increased the carrying values of most of the assets denominated in these currencies.

Changes in the net invested capital by us in our operations over the past two years are shown in the following table:

PERIODS ENDING DECEMBER 31 (MILLIONS)	Change in Brookfield's Net Invested Capital		
	2006/2007	2007	2006
Operating platforms			
Commercial properties	\$ 1,742	\$ 1,030	\$ 712
Power generation	228	57	171
Infrastructure	1,299	781	518
Development and other properties	2,421	1,758	663
Specialty funds	638	(45)	683
Total operating platforms	6,328	3,581	2,747
Private equity investments	43	(68)	111
Cash and financial assets	(1,263)	(282)	(981)
Other assets	219	89	130
	5,327	3,320	2,007
Net invested capital — beginning of period	11,437	13,444	11,437
— end of period	\$ 16,764	\$ 16,764	\$ 13,444

Net capital invested in our operating platforms increased by \$6.3 billion, mostly in our property and infrastructure operations. Capital invested in cash and financial assets declined as we monetized a number of investments to capture value appreciation and fund the expansion of our operating base.

OPERATING PLATFORMS

In this section, we review the results of our principal operating platforms. Further details on our activities can be found in Part 5 – Description of Operating Platforms beginning on page 48.

The following table presents our operating cash flows for the past two years on a segmented basis. The results are classified by operating platforms and separated between the cash flows attributable to our asset management activities and those generated from the capital invested by us in our operating platforms. The cash flows in this section are presented on a net basis (i.e. after deducting associated interest expense and co-investor interests) unless otherwise noted.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Total Operating Cash Flow		Net Operating Cash Flow					
			2007			2006		
	2007	2006	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
Asset management income	\$ 415	\$ 257						
Operating platforms								
Commercial properties	1,566	1,023	\$ 351	\$ 483	\$ 834	\$ 277	\$ 434	\$ 711
Power generation	611	620	68	193	261	62	275	337
Infrastructure	318	206	36	76	112	14	61	75
Development and other properties	412	466	24	279	303	22	225	247
Specialty funds	381	229	143	323	466	56	150	206
Advisory services	—	—	73	—	73	52	—	52
Private equity investments	225	82	—	125	125	—	20	20
Cash and financial assets	702	413	—	695	695	—	396	396
Realization gains	231	633	—	158	158	—	610	610
	4,861	3,929	695	2,332	3,027	483	2,171	2,654
Unallocated expenses								
Financing	(1,786)	(1,185)	—	(302)	(302)	—	(286)	(286)
Operating costs	(464)	(333)	(264)	(180)	(444)	(192)	(124)	(316)
Current income taxes	(68)	(142)	—	(6)	(6)	—	(4)	(4)
Co-investor interests in consolidated operations	(636)	(468)	(65)	(303)	(368)	(54)	(193)	(247)
	\$ 1,907	\$ 1,801	\$ 366	\$ 1,541	\$ 1,907	\$ 237	\$ 1,564	\$ 1,801

Commercial Properties

The following table summarizes the net operating cash flows contributed by our commercial property operations.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Total Operating Cash Flow		Net Operating Cash Flow					
			2007			2006		
	2007	2006	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
Office properties	\$ 1,518	\$ 985	\$ —	\$ 610	\$ 610	\$ —	\$ 536	\$ 536
Retail properties	48	38	—	19	19	—	19	19
	1,566	1,023	—	629	629	—	555	555
Asset management and property services ¹	—	—	351	(146)	205	277	(121)	156
	\$ 1,566	\$ 1,023	\$ 351	\$ 483	\$ 834	\$ 277	\$ 434	\$ 711

¹ Prior to operating costs

Property operations contributed net operating cash flow of \$834 million in 2007 compared to \$711 million in 2006. Operations contributed \$629 million in 2007, modestly higher than 2006. Asset management activities contributed higher levels of operating cash flow during 2007 due to the establishment of new funds during 2006 and 2007, and increases in invested capital as a result of acquisitions.

The following table summarizes assets under management and invested capital in our commercial property operations:

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
					Consolidated		Net Invested Capital	
	2007	2006	2007	2006	2007	2006	2007	2006
Office properties	\$ 29,052	\$ 20,314	\$ 2,298	\$ 1,717	\$ 23,617	\$ 17,016	\$ 4,700	\$ 3,745
Retail properties	1,698	800	600	600	1,698	215	103	28
	\$ 30,750	\$ 21,114	\$ 2,898	\$ 2,317	\$ 25,315	\$ 17,231	\$ 4,803	\$ 3,773

Assets under management, co-investor commitments and invested capital in our commercial office properties all increased with the Multiplex acquisition as discussed earlier. In addition, carrying values increased due to currency appreciation on Canadian properties and the purchase of minority interests in our two flagship Boston properties for approximately \$500 million, bringing our interest in these properties to 100%. Net invested capital increased by \$955 million, which represents the net capital invested by us in Multiplex's office property operations offset by the proceeds from refinancing existing properties. We completed a number of acquisitions in our retail property fund, including that of a large portfolio at the end of 2007, which positions us as one of the largest retail mall owners in Brazil.

Office Properties

Our commercial office portfolios contributed total operating cash flow of \$1.5 billion during 2007 compared to \$1.0 billion in 2006. After deducting interest expenses and the interests of co-investors in these operations, the net operating cash flow was \$610 million compared to \$536 million in 2006. The following table shows the sources of operating cash flow by geographic region:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flow			
	Total		Net	
	2007	2006	2007	2006
North America	\$ 1,416	\$ 857	\$ 1,416	\$ 857
Australasia	62	—	62	—
Europe	40	128	40	128
	1,518	985	1,518	985
Interest expense	—	—	(812)	(442)
Co-investors' interests	—	—	(96)	(7)
	\$ 1,518	\$ 985	\$ 610	\$ 536

Total operating cash flow increased by \$533 million or 54% over 2006 due primarily to the acquisition of a large commercial office portfolio in late 2006. The acquisition was partially funded with property-specific debt and co-investor capital, which contributed towards the \$459 million increase in carrying charges and co-investor interests. After taking these items into consideration, net operating cash flows increased by \$74 million or 14%.

The following table sets out the variances in operating cash flows:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	Variance
Same properties	\$ 735	\$ 696	\$ 39
Acquired properties	628	149	479
Dividend from Canary Wharf	—	87	(87)
Disposition gains	145	44	101
Other	10	9	1
Total operating cash flow	1,518	985	533
Interest expense and co-investor interests	(908)	(449)	(459)
Net operating cash flow	\$ 610	\$ 536	\$ 74

We achieved growth in same property operating cash flow of \$39 million or 6% in 2007, due to new leasing in favourable market conditions. We leased 8.8 million square feet in our North American portfolio during 2007 at an average net rent of \$30 per square foot, replacing leases that averaged \$21 per square foot. Average in-place net rents across the portfolio have increased to \$24 from \$21 at the end of last year. Leasing fundamentals have improved in most of our markets with particular strength in Calgary and New York as well as favourable currency appreciation. We continue to manage our portfolios and tenant relationships on a proactive basis, which can lead to opportunities to re-lease space for increased yields and gains.

Property acquisitions were responsible for most of the increase in operating cash flows, which is to be expected given the stable nature of our long-term lease portfolio and the high credit quality of our tenants. The increase was \$79 million after taking incremental borrowing costs into consideration. We acquired a major portfolio in the United States in late 2006 which increased total operating cash flows by \$408 million (2006 – \$75 million) and net operating cash flows by \$57 million (2006 – \$18 million) after deducting interest expenses and co-investor interests. The acquisition of Multiplex in October 2007 contributed \$62 million of total operating cash flow and \$9 million of net operating cash flow.

Borrowing costs and co-investor share of net operating cash flows increased by \$459 million over 2006, of which \$294 million related to the U.S. portfolio and \$53 million to the Multiplex portfolio. Borrowing costs associated with existing properties increased as a result of refinancing underlevered properties at attractive yields which reduced net operating cash flow but improved return on capital.

Retail

The acquisition of properties within our retail fund resulted in increases in assets under management, consolidated assets and net invested capital. Co-investor commitments remained unchanged during the year, and the fund is now virtually fully invested.

Total operating cash flows increased to \$48 million in 2007 compared to \$38 million in 2006. The increase reflects a disposition gain in 2007 of \$8 million and the impact of acquisitions and higher sales within existing properties. Net operating cash flow was unchanged at \$19 million as the increase in total operating cash flows was offset by integration costs and the reduction in our interest in these properties from 100% to 25% upon their transfer into our retail fund.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flow			
	Total		Net	
	2007	2006	2007	2006
Retail properties ¹	\$ 48	\$ 38	\$ 48	\$ 25
Interest expense	—	—	(6)	(4)
Cash taxes and other expenses	—	—	(10)	—
Co-investors' interests	—	—	(13)	(2)
	\$ 48	\$ 38	\$ 19	\$ 19

¹ The Brascan Brasil Real Estate Partners fund was established in the third quarter of 2006

We received proceeds of \$251 million in 2006 and recorded a gain of \$79 million. The fund completed a major acquisition at the end of 2007 of a 1.7 million square foot portfolio of high quality properties. As a result, the fund is now fully invested and is expected to generate increased cash flows.

Net operating cash flows reflect interest costs on property-specific debt as well as the interests of our co-investors, who have owned 75% of the fund since the fourth quarter of 2006 and accordingly reduced our share of net operating income in 2007.

Asset Management – Commercial Properties

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007			2006		
	Total	Operations	Third Party	Total	Operations	Third Party
Asset management	\$ 185	\$ (146)	\$ 39	\$ 138	\$ (121)	\$ 17
Property services	166	—	166	139	—	139
	\$ 351	\$ (146)	\$ 205	\$ 277	\$ (121)	\$ 156

Asset management fees from third-party clients increased by \$22 million to \$39 million in 2007. Fees attributed to our investment in these operations increased by \$25 million to \$146 million, a 21% increase, reflecting the higher level of capital that we have invested in established funds and directly held assets. Property services fees increased with a higher level of activity.

Power Generation

The following table summarizes the net operating cash flow generated by our power generating operations during 2007 and 2006:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007			2006		
	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
Operations	\$ —	\$ 261	\$ 261	\$ —	\$ 337	\$ 337
Asset management	68	(68)	—	62	(62)	—
	\$ 68	\$ 193	\$ 261	\$ 62	\$ 275	\$ 337

The contribution from operations declined by \$76 million from \$337 million in 2006 to \$261 million in 2007. This reflected a decline in net operating income from our hydroelectric facilities due to lower water levels as well as increased carrying charges.

We increased installed capacity during the year by 117 megawatts through the addition of 18 facilities with expected annual generation of 500 gigawatt hours. We acquired five facilities in North America with installed capacity of 28 megawatts at a cost of \$67 million. We added 13 facilities in Brazil through acquisitions and development at a total cost of \$188 million. In addition, we have six hydroelectric facilities under construction at year end that will expand our capacity by a further 145 megawatts at a total projected cost of \$352 million.

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
	2007	2006	2007	2006	Consolidated Assets		Net Invested	
	2007	2006	2007	2006	2007	2006	2007	2006
Hydroelectric generation	\$ 4,299	\$ 3,756	\$ —	\$ —	\$ 4,299	\$ 3,756	\$ 4,299	\$ 3,756
Wind, pumped storage and cogeneration	602	493	—	—	602	493	602	493
Development	236	60	—	—	236	60	236	60
	5,137	4,309	—	—	5,137	4,309	5,137	4,309
Cash and financial assets	784	618			784	618	784	618
Working capital	881	463			881	463	2	44
Property-specific and subsidiary debt							(4,285)	(3,388)
Co-investor interests							(213)	(215)
	\$ 6,802	\$ 5,390	\$ —	\$ —	\$ 6,802	\$ 5,390	\$ 1,425	\$ 1,368

The book value of total assets under management and consolidated assets increased by \$1.4 billion to \$6.8 billion from \$5.4 billion at the end of last year due primarily to currency appreciation as well as higher levels of working capital and the acquisition of facilities in North America (\$67 million) and Brazil (\$188 million). Net invested capital increased by a smaller amount due to the offsetting impact of currency appreciation on non-U.S. debt and because much of the acquisition cost was funded through project financings on the acquired assets and by financings arranged on existing assets. The increase in operating cash flows over the past

number of years has increased the value of our existing assets enabling us to arrange additional project financing while continuing to maintain a conservative investment grade capitalization.

We believe the intrinsic value of our power assets is much higher than the book value because the assets have either been acquired at attractive prices or held for many years and therefore depreciated for accounting purposes which, in our view, is inconsistent with the nature of hydroelectric generating assets. We have also been successful in acquiring, developing and upgrading many of our facilities on an attractive basis and higher fossil fuel prices have resulted in significantly expanded operating margins for hydroelectric facilities, which have very low operating costs.

The following table summarizes the total and net operating cash flows contributed by our power generating operations during the past two years:

	<i>Total</i>		<i>Operating Cash Flow</i>		
	<i>2007</i>	<i>2006</i>	<i>Net</i>	<i>2006</i>	<i>Variance</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>					
Hydroelectric generation					
North America					
United States	\$ 292	\$ 318	\$ 292	\$ 318	\$ (26)
Canada	171	221	171	221	(50)
Brazil	68	41	68	41	27
Total hydroelectric generation	531	580	531	580	(49)
Wind energy	33	5	33	5	28
Co-generation and pumped storage	47	35	47	35	12
Total other generation	80	40	80	40	40
Total operating cash flows	611	620	611	620	(9)
Other expenses			(7)	(2)	(5)
Interest expenses			(289)	(235)	(54)
Non-controlling interests			(54)	(46)	(8)
Operating cash flow	\$ 611	\$ 620	\$ 261	\$ 337	\$ (76)

Total operating cash flows were \$611 million in 2007 compared to \$620 million in 2006. These results are impacted principally by realized prices and the level of generation which are discussed in the following sections. Net operating cash flows, which reflect interest expenses and co-investor interests, were \$261 million in 2007, a decline from \$337 million in 2006. Interest expense increased by \$54 million reflecting financings completed since the first quarter of 2006, as well as the impact of currency fluctuations on non-U.S. financings.

Realized Prices and Operating Margins

Realized prices from our hydro portfolio increased by 6% over 2006 levels to \$71 per megawatt hour and largely exceeded market prices due to our long-standing strategy to sell much of our power under long-term power sales agreements or financial contracts. Spot electricity prices during the year were generally in line with those of 2006; however, the shorter-term financial contracts under which power was sold were at higher prices. We also generated a higher proportion of our power in higher priced regions than in 2006. Our ability to capture peak pricing and other energy products such as capacity payments also contributes to higher realized prices. The following table illustrates revenues and operating costs for our hydroelectric facilities:

	<i>2007</i>				<i>2006</i>			
	<i>Actual Production</i>	<i>Realized Revenues</i>	<i>Operating Costs</i>	<i>Operating Cash Flows</i>	<i>Actual Production</i>	<i>Realized Revenues</i>	<i>Operating Costs</i>	<i>Operating Cash Flows</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (GWH AND \$ MILLIONS)</i>								
Ontario	1,852	\$ 144	\$ 47	\$ 97	2,059	\$ 150	\$ 39	\$ 111
Quebec	1,407	83	24	59	2,032	118	24	94
New England	1,489	77	30	47	1,438	82	27	55
New York	3,357	210	76	134	3,857	229	69	160
Other	2,786	261	67	194	2,362	211	51	160
Total	10,891	\$ 775	\$ 244	\$ 531	11,748	\$ 790	\$ 210	\$ 580
Per MWh		\$ 71	\$ 22	\$ 49		\$ 67	\$ 18	\$ 49

The increase in operating costs relates to lower power generation at existing facilities where the cost structure is more fixed in nature, such as our New York operations, the addition of generation capacity in higher cost regions, timing of major maintenance expenditures and the impact of a higher Canadian dollar on our Canadian operations.

The contribution from our non-hydro facilities is set forth in the following table. Cash flows increased due to the addition of our wind energy project and the inclusion of our 50%-owned pumped storage facility on a fully consolidated basis.

FOR THE YEARS ENDED DECEMBER 31 (GWH AND \$ MILLIONS)	2007				2006			
	Actual Production	Realized Revenues	Operating Costs	Operating Cash Flows	Actual Production	Realized Revenues	Operating Costs	Operating Cash Flows
Co-generation and pumped storage	1,493	\$ 147	\$ 100	\$ 47	1,168	\$ 100	\$ 65	\$ 35
Wind energy	478	41	8	33	100	7	2	5
Total	1,971	\$ 188	\$ 108	\$ 80	1,268	\$ 107	\$ 67	\$ 40
Per MWh		\$ 95	\$ 55	\$ 40		\$ 84	\$ 53	\$ 31

Generation

Our facilities produced 12,862 gigawatt hours of electricity during 2007, compared with 13,016 gigawatt hours during 2006 and 10,930 gigawatts hours in 2005. We produced 1,684 fewer gigawatt hours from existing hydroelectric capacity owned throughout 2007 and 2006 (i.e. "same store" basis) due to lower water flows; however, this was partially offset by the contribution of 827 gigawatt hours from hydroelectric facilities acquired or developed during 2006 and 2007. Hydroelectric generation was 10% below expected long-term averages for the portfolio as a whole and 7% below 2006 levels. Our reservoirs have been maintained at normal levels for this time of year and, as a result, we should be able to operate our facilities at long-term average levels during 2008, assuming normal water conditions prevail. Our wind facilities, which started operations in the fourth quarter of last year, generated 478 gigawatt hours, slightly lower than our expected long-term average.

The following table summarizes generation over the past three years:

FOR THE YEARS ENDED DECEMBER 31 (GIGAWATT HOURS)	Long-Term Average	Actual Production			Variance to		
		2007	2006	2005	Long Term Average	2006	2005
Existing capacity	10,680	9,547	11,231	9,822	(1,133)	(1,684)	(275)
Acquisitions – during 2006	1,185	1,118	517	—	(67)	601	1,118
Acquisitions – during 2007	250	226	—	—	(24)	226	226
Total hydroelectric operations	12,115	10,891	11,748	9,822	(1,224)	(857)	1,069
Wind energy	534	478	100	—	(56)	378	478
Co-generation and pump storage	1,168	1,493	1,168	1,108	325	325	385
Total generation	13,817	12,862	13,016	10,930	(955)	(154)	1,932

The contribution from our pumped-storage, co-generation and wind facilities increased by \$40 million, reflecting a full year of operation for our northern Ontario wind energy system and a higher contribution from pumped-storage operations.

The \$62 million increase in carrying charges and co-investor interests is due principally to interest expense on debt incurred to acquire and develop new facilities as well as currency appreciation on interest paid on non-U.S. debt. We have invested in our operating base over the past two years, increasing our installed capacity over this period by 15% to 3,891 megawatts and our annual generating capacity by 18% to 13,817 gigawatt hours.

Asset Management – Power Generation

Asset management cash flow is determined by applying a fixed percentage fee to our estimated value of the equity capital invested in these operations. This is an internal allocation that is intended to be consistent with comparable asset management fees incurred elsewhere in our operations.

Infrastructure

Our infrastructure operations consist of timber and electrical transmission operations in the United States, Canada, Chile and Brazil that are owned through a number of managed funds and through direct interests. The net operating cash flows contributed by these operations are summarized in the following table:

	2007			2006		
	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
FOR THE YEAR ENDED DECEMBER 31 (MILLIONS)						
Timberlands	\$ —	\$ 40	\$ 40	\$ —	\$ 32	\$ 32
Transmission	—	62	62	—	37	37
	—	102	102	—	69	69
Asset management	36	(26)	10	14	(8)	6
	\$ 36	\$ 76	\$ 112	\$ 14	\$ 61	\$ 75

The principal change in the financial position of our infrastructure operations was the acquisition of the U.S. Pacific Northwest timberlands as noted in the following table:

	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
					Consolidated Assets		Net Invested	
AS AT DECEMBER 31 (MILLIONS)	2007	2006	2007	2006	2007	2006	2007	2006
Timberlands	\$ 3,675	\$ 1,190	\$ 315	\$ 340	\$ 3,675	\$ 1,190	\$ 1,025	\$ 315
Transmission	3,080	3,143	877	831	760	3,143	620	549
	\$ 6,755	\$ 4,333	\$ 1,192	\$ 1,171	\$ 4,435	\$ 4,333	\$ 1,645	\$ 864

Co-investor commitments represent capital committed by clients to our western Canadian and eastern North American timber funds and the Chilean transmission operations. We commenced accounting for the Chilean transmission operations on an equity basis, as opposed to full consolidation, following a change in the capitalization of the ownership structure which reduced our consolidated assets. Our economic interest was not impacted.

In January 2008 we transferred a number of our ownership interests to Brookfield Infrastructure Partners, a specialty issuer listed on the New York Stock Exchange. We will own 40% of and manage Brookfield Infrastructure pursuant to a long-term agreement. The remaining 60% of Brookfield Infrastructure was distributed to existing Brookfield shareholders. Brookfield Infrastructure will be our primary acquisition vehicle for infrastructure businesses. The establishment of Brookfield Infrastructure is intended to provide investors with what is, in our opinion, a relatively unique and attractive opportunity to invest directly in the infrastructure asset class through a publicly listed security. This also expands the amount of committed capital that we manage and should provide an additional source of capital to fund continued growth in this sector.

Timber

Timber operations contributed \$40 million during 2007 compared with \$32 million in 2006. The increased contribution during 2007 reflects improved performance by our coastal British Columbia operations, which met our operating targets notwithstanding an industry strike that adversely impacted results in the second half of the year.

	Total		Operating Cash Flow		
	2007	2006	Net	2007	2006
FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)					
Timberlands	\$ 158	\$ 87	\$ 158	\$ 87	\$ 71
Interest expense			(85)	(29)	(56)
Co-investors' interests			(33)	(26)	(7)
	\$ 158	\$ 87	\$ 40	\$ 32	\$ 8

Total operating cash flow from our western North American operations increased substantially due to the acquisition of timberlands in the U.S. Pacific Northwest in April of 2007. The associated debt financing also resulted in higher interest costs, which had an offsetting impact on net operating cash flow. As a result, net contribution from the U.S. Pacific Northwest operations, which were acquired in the second quarter of 2007, was minimal after deducting associated interest costs. The slowdown in the U.S.

homebuilding industry resulted in lower demand and prices for premium species such as high quality Douglas-fir. We responded by exploiting the flexibility inherent in timber management which allows us to defer harvesting until prices recover and instead increased harvest levels of whitewood species where margins, although lower than Douglas-fir, held up better.

We increased our harvesting activities in the first half of the year due to the possibility of the strike, which provided us with surplus inventory to work with. Pricing was also better than expected. The operating results compared favourably with the 2006 results, which had been adversely impacted by a prolonged fire season, and adverse weather conditions in the second half of that year.

The following table summarizes the operating results from our timber operations:

FOR THE YEARS ENDED DECEMBER 31 (\$ MILLIONS)	2007			2006		
	Sales (m ³)	Revenue	Harvest (m ³)	Sales (m ³)	Revenue	Harvest (m ³)
Western North America						
Douglas-fir	2,092,200	\$ 191	2,004,400	1,235,800	\$ 120	1,209,000
Whitewood	1,317,800	87	1,232,200	835,900	47	652,000
Other	353,200	51	353,500	241,600	26	233,000
	3,763,200	329	3,590,100	2,313,300	193	2,094,000
Other	1,920,300	89	1,912,000	1,758,600	78	1,724,700
	5,683,500	\$ 418	5,502,100	4,071,900	\$ 271	3,818,700

We sold 5.7 million cubic metres of timber during 2007 compared to 4.1 millions cubic metres during 2006. The U.S. Pacific Northwest operations contributed 1.4 million cubic metres, which represents most of the increase.

Transmission

Transmission operations contributed \$62 million of operating cash flow, net of carrying charges and co-investor interests, compared with \$37 million during 2006 as shown in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Total		Operating Cash Flow		
			Net		
	2007	2006	2007	2006	Variance
Transmission facilities and investments					
Chile	\$ 114	\$ 91			\$ 23
North America	31	28			3
Brazil	15	—			15
	160	119	\$ 160	\$ 119	41
Other expenses			(4)	(8)	4
Interest expense			(65)	(55)	(10)
	160	119	91	56	35
Co-investors' interests			(29)	(19)	(10)
	\$ 160	\$ 119	\$ 62	\$ 37	\$ 25

The increase is due almost entirely to acquisitions of a transmission system in Chile in June 2006 and interests in five Brazilian transmission systems in August 2006. These operations performed in line with expectations, as did our northern Ontario transmission and distribution operations.

The Chilean and Ontario transmission operations performed in line with expectations during the year. In addition, we reported our share of the results of the Brazilian systems, which were acquired at the end of the third quarter of 2006. Net operating income within the Chilean operations prior to interest expense was \$208 million in 2007, compared to \$98 million in 2006.

Effective June 30, 2007, we began accounting for our investment in our Chilean operations using the equity method as a result of changes in the ownership structure, notwithstanding that our economic interest is unchanged. The net contribution to operating cash flow from these operations, after deducting interest costs and co-investor interests, was \$24 million during 2007, compared to \$13 million during our six months of ownership in 2006.

Asset Management – Infrastructure

Asset management activities contributed \$10 million of revenues from third parties during 2007, compared to \$6 million recorded in 2006. The increase is due to a full year contribution from fees associated with our Chilean transmission operations. Total asset management revenues, which include fees earned on our interests in established funds and attributed to directly held interests, increased to \$36 million in 2007 from \$14 million in 2006 due to the expansion of our timber and transmission interests during 2007 and 2006.

Development and Other Properties

Development and other properties include our opportunity invested funds, residential operations, properties under development and properties held for development.

	2007			2006		
	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)						
Opportunity investments	\$ 2	\$ 38	\$ 40	\$ 1	\$ 14	\$ 15
Residential	—	260	260	—	231	231
Under development and held for development	—	3	3	—	1	1
	2	301	303	1	246	247
Asset management	22	(22)	—	21	(21)	—
	\$ 24	\$ 279	\$ 303	\$ 22	\$ 225	\$ 247

Assets under management and invested capital approximately doubled during the year, as shown in the following table, largely due to the acquisition of Multiplex:

	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
					Consolidated		Net Invested Capital	
AS AT DECEMBER 31 (MILLIONS)	2007	2006	2007	2006	2007	2006	2007	2006
Opportunity investments	\$ 1,571	\$ 1,086	\$ 159	\$ 116	\$ 1,571	\$ 1,086	\$ 225	\$ 132
Residential	2,909	2,403	200	—	2,909	2,403	450	484
Under development	3,400	658	—	—	3,400	658	1,696	418
Held for development	1,201	766	—	—	1,201	766	1,170	749
	\$ 9,081	\$ 4,913	\$ 359	\$ 116	\$ 9,081	\$ 4,913	\$ 3,541	\$ 1,783

Assets under management and consolidated assets in our opportunity investments and residential operations both increased by approximately \$500 million. Our first opportunity fund was fully invested during the year following a number of acquisitions. Balances in our residential operations increased due to currency appreciation, the continued expansion of our western Canadian operations and higher than normal inventory levels within our U.S. operations. We formed a \$400 million joint venture between our U.S. homebuilding unit and an institutional investor to invest in residential land in the United States which represents the co-investor commitments in our residential operations. We believe the timing of this fund will enable us to acquire land positions at favourable values due to current weak market conditions.

The amount of capital invested in properties under development increased by \$2.7 billion due mainly to the acquisition of Multiplex, which has \$2.3 billion of projects under way. These projects consist of over 70 properties that will contain more than 20 million square feet of leaseable commercial property space and approximately 18,000 residential lots, homes and units. Multiplex has been an active developer of properties in Australasia and Europe for many years. We also continue the construction and redevelopment of several properties in North America.

The carrying values of properties held for development increased by \$421 million during the year due to continued investment into Alberta residential land to replenish our land bank in the face of strong growth in this market as well as the acquisition of additional agricultural land in Brazil to support our expanding business of contracting sugar cane production to ethanol producers. The increase in carrying values also reflects currency appreciation on our Canadian and Brazilian properties.

Opportunity Investments

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flow			
	Total		Net	
	2007	2006	2007	2006
Net operating income	\$ 67	\$ 42	\$ 67	\$ 42
Disposition gains	70	7	28	7
Interest expense	—	—	(54)	(30)
Co-investors' interests	—	—	(3)	(5)
	\$ 137	\$ 49	\$ 38	\$ 14

Total operating cash flow increased to \$137 million from \$49 million due to disposition gains as well as an increased contribution from portfolio operations, although the increase in the contribution from operations is largely offset by increased interest expenses. Due to the focus on value enhancement and the relative short hold period for properties, we expect that returns will come more from disposition gains as opposed to net rental income, relative to results from our core commercial office portfolios. Our opportunistic investment activities contributed an increase of \$24 million over 2006 due primarily to disposition gains. Our first fund is fully invested and is continuing to sell properties that have been successfully repositioned while we continue to invest the capital committed to our second fund.

Residential

We benefitted from the diversification of our residential operations as the impact of the slowdown in the U.S. was offset by continued growth in our Canadian and Brazilian operations. Our Canadian operations, which are concentrated in Alberta, continued to benefit from strong growth in this energy-based economy as well as the stronger currency which increased their contribution to \$237 million from \$144 million, offsetting the decline in the contribution from our U.S. operations. Our operations in Brazil performed well during 2007.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flow			
	Total		Net	
	2007	2006	2007	2006
Residential properties	\$ 375	\$ 416	\$ 375	\$ 416
Impairment charge – U.S. operations	(103)	—	(103)	—
Interest expense ¹			(18)	(23)
Cash taxes			18	(93)
Co-investors' interests			(12)	(69)
	\$ 272	\$ 416	\$ 260	\$ 231

¹ Portion of interest expensed through cost of sales

Net operating cash flow increased between 2007 and 2006 as record results in Canada more than offset a slowdown in our U.S. operations.

Canada

We continue to benefit from strong demand for housing in Canada, particularly in Alberta where we hold a 29% market share in the important Calgary market, with year-to-date results more than 50% higher than 2006. The contribution increased by more than 50%, although 49% of this increase accrues to our co-investors in Brookfield Properties on both a total and net basis. Most of the land holdings were purchased in the mid-1990s or earlier, resulting in particularly strong margins due to continued strong energy investment in Calgary, although the high level of activity is creating some upward pressure on building costs. Operating margins during 2007 were 34% compared to 31% for 2006.

Based on the current market environment, we expect another strong year in 2008 although likely not as strong as the exceptional results in 2007. We own approximately 82,900 lots in these operations of which approximately 6,400 lots were under active development at year end and 76,500 lots are included in development assets because of the length of time that will likely pass before they are actively developed.

United States

Our U.S. operations contributed \$46 million of cash flow before interest, taxes and non-controlling interests during 2007 as demand for new homes slowed and margins narrowed, compared to \$236 million during 2006. In addition, these operations recorded an impairment charge of \$103 million on higher cost land inventory positions. The net operating loss from this unit, after deducting interest, taxes and non-controlling interests was \$21 million, compared with a contribution of \$76 million during 2006. The gross margin from housing sales was approximately 17% compared with 26% last year. We closed 839 units during the year (2006 – 1,181) at an average selling price of \$662,000 (2006 – \$679,000).

We do not expect the current supply and demand imbalance in these markets to be worked through in a meaningful way during 2008. Net new orders during 2007, which will be recognized in earnings as the transactions close, were 735 units, compared to 960 units achieved in 2006. Backlog at the end of 2007 was 155 units (2006 – 259 units). We own or control 25,400 lots through direct ownership, options and joint ventures.

Brazil

We own substantial density rights that will provide the basis for continued growth in our key markets of Rio de Janeiro and São Paulo, and continued to add to these rights during the year.

Under Development and Held for Development

Properties that are under development and held for development do not contribute meaningful cash flow during the development process as costs are typically capitalized and revenues are applied against these costs.

Specialty Funds

Specialty investment funds, which include our bridge lending, restructuring and real estate finance generated net operating cash flow of \$466 million during 2007, more than double the operating results during 2006.

	2007			2006		
	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)						
Operations						
Bridge lending	\$ —	\$ 70	\$ 70	\$ —	\$ 65	\$ 65
Restructuring	—	247	247	—	82	82
Real estate finance	—	24	24	—	17	17
	—	341	341	—	164	164
Asset management	143	(18)	125	56	(14)	42
	\$ 143	\$ 323	\$ 466	\$ 56	\$ 150	\$ 206

The following table summarizes the assets and capital in our specialty funds:

	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
					Consolidated Assets		Net Invested	
AS AT DECEMBER 31 (MILLIONS)	2007	2006	2007	2006	2007	2006	2007	2006
Bridge lending	\$ 1,187	\$ 1,452	\$ 1,510	\$ 470	\$ 488	\$ 637	\$ 488	\$ 622
Restructuring	1,538	977	753	652	1,538	977	361	377
Real estate finance	4,637	5,438	1,225	937	685	183	263	183
Real estate services	125	—	59	59	25	—	25	—
	\$ 7,487	\$ 7,867	\$ 3,547	\$ 2,118	\$ 2,736	\$ 1,797	\$ 1,137	\$ 1,182

A number of our bridge loans were repaid during the year, resulting in a lower level of assets under management, consolidated assets and net invested capital. During 2007 we increased co-investor capital committed to our second restructuring fund by \$140 million and closed C\$935 million in commitments to a junior and senior bridge loan fund, including \$240 million in commitments from Brookfield, and our second real estate finance fund, with \$450 million in total commitments including \$202 million from Brookfield. The increase in assets under management and consolidated assets in our restructuring operations reflects new investments that are accounted for on a fully consolidated basis. Net invested capital was relatively unchanged as the capital invested in these new restructuring initiatives was offset by the recovery of capital from realized investments.

Bridge Lending

The contribution from bridge lending operations increased by 8% over 2006 due to higher average outstanding loan balances and commitment fees, together with higher interest rates over much of the year. Operating cash flows, which represent the return on our capital and do not reflect asset management fees, totalled \$70 million during 2007 compared to \$65 million during 2006. The average level of invested capital over the full year, at \$613 million, was relatively consistent with 2006. Associated yields were also relatively consistent year over year.

Restructuring

The following table summarizes the results from our restructuring operations:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flow			
	Total		Net	
	2007	2006	2007	2006
Operating cash flow	\$ 54	\$ 88	\$ 54	\$ 88
Disposition gain – Stelco	231	—	231	—
Settlement gain – Western Forest	—	59	—	59
	285	147	285	147
Other expenses	—	—	(4)	(3)
Interest expense	—	—	(20)	(13)
Non-controlling interests	—	—	(14)	(49)
	\$ 285	\$ 147	\$ 247	\$ 82

In our restructuring operations, we successfully concluded our involvement with Stelco, with an offer by U.S. Steel to acquire 100% of the company. Our share of the proceeds was approximately \$274 million, giving rise to a disposition gain of \$231 million. The favourable outcome should also contribute towards meaningful performance income from our carried interest in the fund. The 2006 results included a \$59 million net contribution from a western Canadian based lumber producer following the settlement of a dispute between the U.S. and Canada over the export by Canadian producers of softwood lumber. Net operating cash flows excluding these items were \$54 million in 2007 compared to \$23 million during 2006. The increase reflects a higher level of investor capital and improved performance by our investments.

Real Estate Finance

The real estate finance group increased the level of invested assets by originating a number of high quality investment opportunities resulting in a greater contribution to operating cash flows. We expect to record increased cash flows, assets under management and investment returns from our second real estate finance fund during 2008. These activities contributed \$24 million of net operating cash flow during 2007 as shown in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flows			
	Total		Net	
	2007	2006	2007	2006
Real estate finance investments, net of debt	\$ 68	\$ 42	\$ 66	\$ 42
Less: co-investor interests	(47)	(28)	(47)	(28)
Real estate finance fund	21	14	19	14
Securities – directly held	2	2	2	2
Financial assets – Mortgage REIT	3	1	3	1
	\$ 26	\$ 17	\$ 24	\$ 17

The portfolio continues to perform in line with our expectations and we expect to receive full payment of interest and principal over the remaining term of our investments.

Asset Management – Specialty Funds

Asset management activities within our specialty funds operations contributed \$125 million of third-party income during 2007, up substantially over 2006. A large portion of the increase is due to transaction fees arising from our efforts to establish a major U.S. retail fund by way of an acquisition and associated financing fees. The 2007 results also reflect a higher level of base management fees arising from the follow-on funds in each sector of this business.

Advisory Services

We manage equity and fixed income securities and provide investment banking services all with a particular focus on the property and infrastructure sectors. The results of these activities are presented in the following table:

	2007			2006		
	Asset Management	Operations	Total Platform	Asset Management	Operations	Total Platform
FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)						
Real estate and fixed income securities	\$ 39	\$ —	\$ 39	\$ 36	\$ —	\$ 36
Investment banking	34	—	34	16	—	16
	\$ 73	\$ —	\$ 73	\$ 52	\$ —	\$ 52

The management of real estate and fixed income securities produced revenues of \$39 million, which consist largely of base management fees. Management fees increased over 2006 levels due to growth in assets under management from an average level of \$21 billion during 2006 to \$23 billion during 2007.

Our real estate investment banking and advisory group contributed \$34 million of fees during 2007. The group advised on transactions totalling \$9.3 billion in value during the year, and secured a number of prominent mandates.

The following table summarizes assets under management within our advisory activities. We typically do not invest our own capital in these strategies as the assets under management tend to be securities as opposed to physical assets.

	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
	2007	2006	2007	2006	Consolidated Assets		Net Invested	
AS AT DECEMBER 31 (MILLIONS)					2007	2006	2007	2006
Real estate and fixed income securities								
Fixed income	\$ 20,210	\$ 19,711	\$ 20,210	\$ 19,711	\$ —	\$ —	\$ —	\$ —
Equity	6,027	749	6,027	749	—	—	—	—
	\$ 26,237	\$ 20,460	\$ 26,237	\$ 20,460	\$ —	\$ —	\$ —	\$ —

Assets and capital commitments increased during the year due primarily to the acquisition of a real estate and infrastructure equities manager with \$6 billion of securities under management during the fourth quarter of 2007.

Private Equity Investments

The net operating cash flow generated by our private equity investments increased to \$125 million from \$20 million in 2006. We also recorded increased returns from our insurance operations, following the impact of storm-related losses in the first half of 2006.

	Operating Cash Flow			
	Total		Net	
FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	2007	2006
Forest products	\$ 17	\$ 2	\$ —	\$ (25)
Infrastructure	6	5	6	5
Business operations	196	73	117	36
Property	6	2	2	4
	\$ 225	\$ 82	\$ 125	\$ 20

Business operations include our insurance activities, which contributed improved results. These operations had been adversely impacted by storm-related losses in the first half of 2006. We are exploring a variety of options to surface the value of our insurance businesses, which could result in a reduced ownership interest in the future.

We began consolidating the results of Fraser Papers during the third quarter of 2007 following an increase in our ownership interest to 56%. Cash flow in the table above reflects our proportionate interest in Fraser Papers' cash flows. Total operating cash outflow was \$15 million, and represented a net outflow of \$22 million after taking into consideration debt and minority interests. In connection with Fraser Papers' January 2008 equity rights offering, we increased our equity interest to 71% of the outstanding common shares.

Consolidated assets increased to \$3.9 billion at the end of 2007 compared to \$3.5 billion at the end of 2006 due to the consolidation of our investments in Fraser Papers and Banco Brascán for accounting purposes following the increase in our interests in the companies to more than 50%. The incremental amount invested in each case was modest and accordingly our net invested capital remained relatively unchanged at \$1.3 billion.

Cash and Financial Assets

Income from our cash and financial assets increased to \$695 million from \$396 million. The 2007 results include a gain of \$378 million on the monetization of an exchangeable debenture during 2007. We sold a number of common share investments during 2007, realizing meaningful gains in the process, which enabled us to report favourable returns on our invested capital in addition to the exchangeable debenture gain. These returns exceed our expectations and shareholders should not expect us to repeat this performance with any degree of certainty.

Operating cash flow includes a net gain of \$378 million from the sales of our holdings of exchangeable debentures during the year. This consists of two components: an amount of \$331 million which represents the accrued gain on the debentures up to December 31, 2006; and \$47 million of income representing the change in value between December 31, 2006 and the time of sale. Under the accounting transitional rules for Financial Instruments, the \$331 million portion of the gain has been recorded directly into retained earnings. We have included this amount in operating cash flow to ensure that the full gain is recognized in our operating track record. The exchangeable debentures are the only financial instruments we hold that gave rise to a significant adjustment of this nature.

Consolidated cash and financial assets decreased to \$1.4 billion during 2007 due to the sale of exchangeable debentures and common shares to capture value appreciation and to fund acquisitions during the year. Net invested capital reflects broker deposit liabilities and a small number of borrowed securities that have been sold short.

As part of our ongoing risk management and value creation activities, we establish market positions using total return swaps and credit derivatives. As at December 31, 2007, we maintain common equity positions with a notional value of \$70 million through total return swaps. We also bought protection against widening credit spreads through credit default swaps with a total notional value of \$2.4 billion, which have a limited downside and benefit from increases in credit spreads and defaults of the underlying debt. We recorded gains of \$129 million during 2007 on these credit default swaps.

Financing Costs

Financing costs include interest expense on corporate borrowings, certain subsidiary borrowings and capital securities as set out in the following table.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	Variance
Corporate borrowings	\$ 146	\$ 126	\$ 20
Subsidiary borrowings	66	64	2
Capital securities	90	96	(6)
	\$ 302	\$ 286	\$ 16

Interest on corporate borrowings increased during the year due to a higher level of average borrowings that were incurred in the course of expanding our operating base.

Operating Costs

Operating costs relate to our asset management and corporate activities.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	Variance
Asset management			
Asset management activities	\$ 111	\$ 69	\$ 42
Property services	153	123	30
	264	192	72
Corporate and other costs	180	124	56
	\$ 444	\$ 316	\$ 128

Operating costs include those of Brookfield Properties, and reflect the costs of our asset management activities as well as costs which are not directly attributable to specific business units. Corporate and asset management costs increased from \$193 million in 2006 to \$291 million in 2007 on a net basis, due to the continued expansion of our business and increased level of activity, in particular costs associated with the integration of a major property portfolio, a number of major corporate and asset management initiatives and the expanded resources requirements.

We have continued to invest in our business as we grow, which has resulted in higher operating costs, and also incurred a number of transaction and other costs related to growth initiatives. We believe this investment will enable us to expand our business without a commensurate increase in costs, thereby resulting in expanded margins.

Co-investor Interests in Consolidated Operations

Co-investor interests relate primarily to the 49% minority equity interest held by others in our North American property subsidiary, Brookfield Properties Corporation.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	Variance
Asset management	\$ 65	\$ 54	\$ 11
Operating returns	303	193	110
	\$ 368	\$ 247	\$ 121

The increase in operating returns reflects the increase in operating cash flows from our Canadian residential property business, which is owned through Brookfield Properties, as well as continued growth in the returns from our North American office property portfolios.

NET INCOME

Net income was \$787 million in 2007, compared to \$1,170 million in 2006. The decline reflects the lower level of realization gains in 2007. Furthermore, net income excludes \$331 million of the gains on sales of the exchangeable debentures that were recorded in retained earnings due to a prescribed accounting change. These items more than offset the increase in operating cash flow from our ongoing operations. Net income is also reduced by depreciation and amortization with respect to assets purchased since the latter portion of 2006. In our view, these assets will generate increasing cash flows over an extended period of time and require sustaining capital expenditures well below the amount of depreciation and amortization being recorded.

The following table reconciles net income and operating cash flow:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Operating cash flow and gains	\$ 1,907	\$ 1,801
Less: dividends from equity accounted investments	(21)	(66)
dividends from Canary Wharf Group	—	(87)
exchangeable debenture gain	(331)	—
	1,555	1,648
Non-cash items		
Depreciation and amortization	(1,034)	(600)
Equity accounted loss from investments	(72)	(36)
Provisions and other	(112)	57
Future income taxes	(88)	(203)
Non-controlling interests	538	304
Net income	\$ 787	\$ 1,170

Depreciation and amortization prior to non-controlling interests increased due to the acquisition of additional assets in a number of segments during 2006 and 2007. Depreciation and amortization for each principal operating segment is summarized in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Commercial properties	\$ 572	\$ 294
Power generation	164	124
Infrastructure	138	68
Development and other properties	65	36
Specialty funds and private equity investments	89	71
Other	6	7
	\$ 1,034	\$ 600

In particular, the U.S. core office portfolio and the Pacific Northwest timberlands contributed \$323 million of depreciation in aggregate, towards the overall increase of \$434 million from 2006.

We recorded net equity accounted losses of \$72 million during the year from private equity investments, including Norbord, Fraser Papers and Stelco. Norbord and Fraser Papers faced a weak price environment for their principal products, in addition to higher input costs. We increased our interest in Fraser Papers to 56% during the third quarter of 2007 and began to consolidate our interest at that time, and sold our interest in Stelco during the fourth quarter of 2007 for a \$229 million gain which reflects the cash gain of \$231 million adjusted to reflect non-cash tax provisions.

The following table summarizes earnings from our equity accounted investments for the past two years:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Norbord	\$ (17)	\$ 37
Fraser Papers	(23)	(62)
Stelco	(32)	(11)
	\$ (72)	\$ (36)

Provisions and other, which largely represent revaluation items, contributed a loss of \$112 million in 2007 compared with an income of \$57 million in 2006, and are summarized in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Norbord exchangeable debentures	\$ (9)	\$ 59
Interest rate contracts	(64)	7
Power contracts	(63)	—
Stelco recovery of equity accounted losses	43	—
Other	(19)	(9)
	\$ (112)	\$ 57

Revaluation items are non-cash accounting adjustments that we are required to record under GAAP to reflect changes in value of contractual arrangements that we do not believe are appropriately included in operating cash flow. Items being revalued include debentures issued by us that are exchangeable into 20 million Norbord common shares, which are revalued based on changes in the Norbord share price during the period. We hold the 20 million shares into which the debentures are exchangeable, but are not permitted to mark the investment to market.

Revaluation items also include the impact of revaluing fixed rate financial contracts that we maintain in order to provide an economic hedge against the impact of possible higher interest rates on the value of our long duration interest sensitive assets. The U.S. 10-year treasury rate moved from 4.70% to 4.02% between December 31, 2006 and December 31, 2007, which led to a \$64 million decline in the value of these contracts, however we believe that this is offset by a corresponding impact on the value of the assets being hedged. Accounting rules require that we revalue these contracts each period even if the corresponding assets are not revalued.

In our power operations, we enter into long-term contracts to provide generation capacity, and are required to record changes in the value of these contracts through net income whereas we are not permitted to record the corresponding increase in the value of the capacity that we have pre-sold.

Our future income tax provision was lower than in 2006, due principally to the inclusion in that year of charges related to a reduction in income tax rates that lowered the value of our tax pools. Future income taxes in the first and third quarters of 2007 included a reversal of an income tax liability associated with our U.S. homebuilding operations following the receipt of a final assessment from income tax authorities in respect of a prior tax year.

REALIZATION GAINS

The following table summarizes major realization items included in operating results:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Platform	Cash Flow From Operations		Net Income	
		2007	2006	2007	2006
Exchange seats sale	Private equity	\$ 204	\$ —	\$ 204	\$ —
Banco Brascán joint venture gain	Private equity	27	—	27	—
Core office properties – debt breakage	Property – office	(27)	—	(27)	—
Residential Brazil IPO	Property – residential	—	269	—	269
Sale of Accor joint venture interest	Private equity	—	149	—	149
Brookfield Properties dilution gain	Property – office	—	110	—	110
Fund formation gains	Property – retail / Infrastructure	—	105	—	105
Less: income taxes and non-controlling interest		(33)	(23)	(27)	(87)
		\$ 171	\$ 610	\$ 177	\$ 546

Major realization items in 2007 included gains of \$204 million from the sale of exchange seats and joint-venture interests within our Brazilian financial operation. Realization items during 2006 included gains of \$269 million on the formation of our publicly listed Brazil residential properties subsidiary, and \$105 million on the formation of our Brazilian retail property fund and our eastern timber fund. We also recorded gains of \$149 million on the sale of our interests in a joint venture with the Accor Group of France and a \$110 million gain on the partial monetization of our North American core office property business. These items were offset by cash taxes and non-controlling interests of \$33 million and \$23 million during 2007 and 2006, respectively.

The impact of items of this nature on net income, in addition to the foregoing, also reflected non-cash income tax provisions recorded for accounting purposes.

CAPITALIZATION AND LIQUIDITY

The strength of our capital structure and the liquidity that we maintain enables us to achieve a low cost of capital for our shareholders and at the same time provides us with the flexibility to react quickly to potential investment opportunities as they arise, as well as to withstand sudden adverse changes in economic circumstances.

Our capitalization is comprised largely of long-term financings and permanent equity. We believe this is the most appropriate method of financing our long-term assets, and the high quality of the assets and the associated cash flows enable us to raise long-term financing in a cost effective manner. We prudently finance our operations with debt and other forms of leverage that match the profile of the business and without any recourse to the Corporation. The leverage employed is reflective of the liquidity and duration of the assets and operations being financed and varies from fund to fund and operation to operation. Our policy is to not guarantee the obligations of any fund or operating entity other than our equity commitment except in very limited circumstances. Funds also have the ability to raise additional capital through asset sales or debt financings, from their stakeholders, including us, from the public capital markets or through private issuances.

To ensure we are able to react to investment opportunities quickly and on a value basis, we typically maintain a high level of liquidity at the corporate level. Our primary sources of liquidity consist of our cash and financial assets, net of deposits and other associated liabilities, and undrawn committed credit facilities. These totalled \$2.0 billion at the corporate level at the end of 2007, compared to \$2.1 billion at December 31, 2006. Furthermore, we endeavour to structure our invested capital in a manner that enables future monetization of our investments as desired.

We generate substantial liquidity within our operations on an ongoing basis through our free cash flow, which varies between \$1.5 billion to \$2.0 billion on an annual basis, as well as from the ongoing turnover in assets with shorter investment horizons and periodic monetization of our longer dated assets through the sale of co-investor participations, divestitures and refinancings.

Accordingly, we consider ourselves to have the necessary liquidity to both manage our financial commitments and to capitalize on opportunities to invest capital at attractive returns. Nevertheless, we are cognizant of the current instability in the capital markets and continue to allocate capital in a prudent manner.

The following table presents Brookfield's capitalization using book values on a fully consolidated and net invested basis together with the associated cash flows:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Cost of Capital ¹ 2007	Book Value				Operating Cash Flow ²			
		Consolidated		Net Invested Capital		Total		Net	
		2007	2006	2007	2006	2007	2006	2007	2006
Corporate borrowings	7%	\$ 2,048	\$ 1,507	\$ 2,048	\$ 1,507	\$ 146	\$ 126	\$ 146	\$ 126
Non-recourse borrowings									
Property-specific mortgages	7%	21,644	17,148	—	—	1,226	751	—	—
Subsidiary borrowings ³	7%	7,463	4,153	711	668	324	212	66	64
Other liabilities	9%	11,102	6,497	3,148	1,771	532	475	450	320
Capital securities	6%	1,570	1,585	1,570	1,585	90	96	90	96
Non-controlling interest in net assets	20%	4,256	3,734	1,773	1,829	636	468	368	247
Shareholders' equity									
Preferred equity	5%	870	689	870	689	44	35	44	35
Common equity	20%	6,644	5,395	6,644	5,395	1,863	1,766	1,863	1,766
	9.5%	\$ 55,597	\$ 40,708	\$ 16,764	\$ 13,444	\$ 4,861	\$ 3,929	\$ 3,027	\$ 2,654

¹ Based on operating cash flows as a percentage of average book value

² Interest expense in the case of borrowings. Attributable operating cash flows in the case of minority and equity interests, including cash distributions. Current taxes and operating expenses in the case of accounts payable and other liabilities

³ Net amounts represent subsidiary obligations guaranteed by the Corporation or issued by corporate subsidiaries

Our consolidated capitalization, which includes 100% of the obligations of partially owned consolidated entities, increased by \$14.9 billion during the year. The increase reflects additional property-specific mortgage debt on acquired assets and expanded financing on existing properties, as well as additional working capital associated with acquired operations.

Our capitalization on a net invested capital basis increased by \$3.3 billion. This basis excludes property-specific borrowings and other financial obligations that have no recourse to the Corporation. The book value of our common equity increased \$1.2 billion to \$6.6 billion due to the accumulation of undistributed net earnings and unrealized gains on securities. Corporate borrowings increased by \$541 million due mainly to the issuance of 10-year bonds during the year.

The market value of our common equity capitalization was \$22 billion as at December 31, 2007, compared to \$20 billion at the end of 2006.

Deconsolidated Capitalization

As noted above, consolidated capitalization includes 100% of the debt within consolidated entities, even though in most cases we only own a portion of the entity and therefore our pro-rata interest in this debt is much lower. Accordingly, we believe that the level of debt on this basis is relevant only in relation to the associated consolidated assets, as opposed to our equity. We focus primarily on our deconsolidated capitalization in assessing financial leverage.

The table on the following page presents our deconsolidated capitalization, i.e. excluding the capitalization of Brookfield Properties and other consolidated entities. Our deconsolidated debt to capitalization levels remain well within our target of 20% to 30% on a book value basis and, in our opinion, are very conservative on a market value basis at 10%.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Capitalization Market Value ¹		Brookfield Invested Capital		Operating Cash Flow			
	2007	2006	2007	2006	Underlying		Remitted	
					2007	2006	2007	2006
Corporate borrowings	\$ 2,048	\$ 1,507	\$ 2,048	\$ 1,507	\$ 146	\$ 126	\$ 146	\$ 126
Subsidiary borrowings ²	711	668	711	668	66	64	66	64
Other liabilities	1,401	983	1,401	983	329	234	329	234
Capital securities	517	663	517	663	32	44	32	44
Non-controlling interests	9	69	9	69	2	1	2	1
Shareholders' equity								
Preferred equity	870	689	870	689	44	35	44	35
Common equity	22,262	19,947	6,644	5,395	1,863	1,766	1,661	1,535
Total capitalization / cash flows	\$ 27,818	\$ 24,526	\$ 12,200	\$ 9,974	\$ 2,482	\$ 2,270	\$ 2,280	\$ 2,039
Debt to total capitalization ³	10%	9%	23%	22%				
Interest coverage ⁴					12x	12x	11x	11x
Fixed charge coverage ⁵					9x	8x	8x	8x

¹ Common equity values based on period end market prices

² Guaranteed by the Corporation or issued by corporate subsidiaries

³ Corporate and subsidiary borrowings as a percentage of total capitalization

⁴ Total cash flows divided by interest on corporate and subsidiary borrowings

⁵ Total cash flows divided by interest on corporate and subsidiary borrowings and distributions on capital securities and preferred equity

⁶ Excludes the capitalization of Brookfield Properties Corporation

Corporate Borrowings

Our corporate borrowings have an average term of 11 years and more than 50% of the maturities extend beyond 2012. We hold cash, financial assets and have committed undrawn bank facilities which do not mature until 2011 that are available to fund shorter-term maturities if we determine that this approach results in a lower cost of capital.

YEARS ENDED DECEMBER 31 (MILLIONS)	Average	2008	2009	2010	2011	2012	Beyond	Total
	Term							
Commercial paper and bank borrowings	2	\$ 117	\$ 17	\$ 17	\$ 16	\$ —	\$ —	\$ 167
Publicly traded term debt	11	299	—	199	—	346	1,037	1,881
Total	11	\$ 416	\$ 17	\$ 216	\$ 16	\$ 346	\$ 1,037	\$ 2,048
Percentage of total		20%	1%	10%	1%	17%	51%	100%

Property-specific and Subsidiary Borrowings

Property-specific financings and subsidiary borrowings have no recourse to the Corporation except for a limited number of exceptions, and are typically secured only by the specific assets or operations being financed. In particular, subsidiary borrowings include \$711 million (2006 – \$668 million) of financial obligations that are either guaranteed by the Corporation or are issued by corporate subsidiaries. Carrying charges incurred in connection with these obligations totalled \$66 million during 2007 (2006 – \$64 million). The maturities are well diversified and have an average term of seven years and four years, respectively, as illustrated in the following table:

YEARS ENDED DECEMBER 31 (MILLIONS)	Average	2008	2009	2010	2011	2012	Beyond	Total
	Term							
Property-specific borrowings	7	\$ 4,336	\$ 2,357	\$ 554	\$ 4,807	\$ 1,152	\$ 8,438	\$ 21,644
Subsidiary borrowings	4	1,872	2,803	530	253	86	1,919	7,463

We have two financings of note that mature in the next two years. The first is a \$1.2 billion loan secured by the U.S. Pacific Northwest timberlands acquired during the first half of 2007. This loan is due in October 2008 and is in the process of being refinanced on a long-term basis. The second is a \$1.6 billion loan secured by our Multiplex operations, which we acquired during 2007. This loan does not mature until March 2009 and represents a loan-to-value of less than 60%. We plan to repay a portion of this loan with asset sales and refinance the balance on a traditional long-term financing basis during 2008 and early 2009.

Shareholders' Equity

Preferred equity consists of perpetual preferred shares that represent an attractive form of leverage for common shareholders. During the year we issued C\$200 million of perpetual preferred shares with a coupon of 4.75%.

The book value of our common equity increased by 23% during 2007 and by 26% over the past three years as illustrated in the following table:

AS AT DECEMBER 31 (MILLIONS)	2007	2006	2005
Common equity – book value	\$ 6,644	\$ 5,395	\$ 4,514
Common equity – market value	22,262	19,947	13,870

The market value of our common equity increased to \$22.3 billion at the end of 2007, representing an increase of \$8.4 billion over the past two years, and a rate of 31% over the past three years.

OUTLOOK

The fundamentals in most of our businesses remain positive.

Within our asset management activities, we continue to seek to expand our distribution capabilities, our client base and the amount of capital committed to us which should increase the capital available to invest and lead to growth in asset management income and assets under management. This is an area of particular emphasis for us in 2008.

The investment market has become less competitive and acquisition prices have declined due in large part to reduced availability of low-cost capital for many investors. We are well capitalized with access to liquidity from our own balance sheet as well as our clients, financial partners and capital markets. We believe the breadth of our operating platform and our disciplined approach to investing should enable us to continue to invest capital on a favourable basis.

In our office property sector, the leasing markets in which we operate improved measurably during most of 2007, with the most significant improvements taking place in New York and Calgary. While fundamentals remain favourable for well located high quality properties such as ours, economic weakness in North America will affect demand by users of office space over the medium term. As a result, rental rates are expected to stabilize and possibly decline in some markets, and any significant slowdown in the economy could have a further dampening effect on the office markets. We were able to increase the average lease rate in our portfolio during the past year, and our strong tenant lease profile, low vacancies and rental rates that in most properties are substantially below current market rates, give us a high level of confidence that we can achieve our operating targets in 2008. A general lack of development, especially in central business districts, has also created stability from a supply perspective.

Residential markets remain mixed in our core markets. The current supply/demand imbalance in U.S. markets has reduced operating margins and must be worked through before we will see margin improvements and growth. Our Alberta operations have benefitted greatly from the continued expansion of activity in the oil industry. Most of the land holdings were purchased in the mid-1990s or earlier and as a result have an embedded cost advantage today. This has led to particularly strong margins, although the high level of activity is creating some upward pressures on building costs, production delays due to labor shortages and, most recently, supply concerns as a result of an increase in resale and standing inventory.

Our power operations experienced lower water levels during 2007 following above average conditions in 2006. Market prices were relatively unchanged year over year, however, our strategy of locking in future prices through contractual arrangements and our ability to deliver power at peak price intervals enabled us to achieve higher realized prices than in 2006. We are well positioned to achieve our hydrology targets in 2008 based on current storage levels if normal hydrology conditions prevail. If this occurs, we should achieve higher generation levels based on the expansion in our operating base. We have nearly 80% of our power sales fixed for the next two years at favourable prices. Accordingly, we expect to record higher operating cash flows during 2008.

We continue to expand our specialty funds operations by committing additional resources and launching new funds. We will focus on maintaining a high level of invested capital, and deploy the capital from new funds, which should lead to continued growth. We expect the current difficulties in credit markets will lead to a greater number of opportunities for our restructuring operations and more attractive pricing for our bridge and real estate finance groups.

Within our infrastructure operations, we expect our transmission operations to provide returns consistent with those recorded in 2007. We expect our timber operations to experience lower demand and pricing due to weakness in the U.S. homebuilding sector, although we intend to mitigate this by adjusting our harvest plan to preserve value and by increasing exports to Asia. The net contribution from our existing infrastructure operations will be reduced in 2008 due to the ownership interests in these operations that are now held by unitholders in Brookfield Infrastructure Partners.

The increase in the value of various currencies against the U.S. dollar is expected to have a positive impact on the contribution from our operations that are denominated in these other currencies, notably the Canadian dollar, the Brazilian real and the Australian dollar. The recent reductions in interest rates in most economies has a beneficial impact on our results, although most of our cash flows are fixed rate in nature.

There are many factors that could impact our performance in 2008, both positively and negatively. And while we expect to demonstrate continued growth during 2008, our 2006 and 2007 reported results may be unrealistic comparative measures due to the significant realization and other gains recorded during each year. It is for that reason, amongst others, that we measure our growth over the long term as opposed to quarter-over-quarter or year-over-year. We describe the material aspects of our business environment and risks on Part 4 of this MD&A.

We will continue to manage our business with the objective of reducing the impact of short-term market fluctuations through the use of long-term revenue contracts and long-term financings, among other measures. This approach to business provides us with confidence that we will meet our ongoing performance objectives with respect to cash flow growth and value creation.

PART 3 – BUSINESS STRATEGY

In this section we discuss our business strategy and our capabilities as they relate to our ability to execute our strategy. We also describe the key performance factors that are necessary to successfully implement this strategy and key financial measures that are indicative of our progress. We also explain the terminology that is used throughout this section and our rationale for selecting the key financial measures that we use to assess our business.

OUR STRATEGY

We are a global asset management company focused on property, power and infrastructure assets. Our goal is to establish Brookfield as a global asset manager of choice for investment clients who wish to benefit from the ownership of these types of assets. We have spent many years building high quality operating platforms that enable us to acquire, finance and optimize the value of assets for our own benefit, and for our clients whose capital we manage.

We believe that the best way to create long-term shareholder value is to generate increasing operating cash flows, measured on a per share basis, over a very long period of time. Accordingly, we concentrate on high quality long-life assets that generate sustainable cash flows, require minimal sustaining capital expenditures and tend to appreciate in value over time. Often these assets will benefit from some form of barrier to entry due to regulatory, physical or cost structure factors. Consistent with this focus, we own and operate large portfolios of core office properties, hydroelectric power generating stations, private timberlands and regulated transmission systems that, in our opinion, share these common characteristics. These assets represent important components of the infrastructure that supports the global economy.

We believe the demand from institutional investors to own assets of this nature is increasing as they seek to earn increasing yields to meet their investment objectives. These assets, in our view, they represent attractive alternatives to traditional fixed income investments, providing in many cases a “real return” that increases over time, relatively low volatility and strong capital protection. There is a substantial supply of investment opportunities in the form of existing assets as well as the need for continued development in an ever expanding global economy. At the same time there are relatively few global organizations focused on managing assets of this nature as a primary focus on their strategy.

Our strategy for growth is centered around expanding our assets under management, which should lead to increased fee revenues and opportunities to earn performance returns. We plan to achieve this within our existing operating platforms, through geographic expansion beyond our current focus in North America, South America, Europe and Australia, and by developing and acquiring platforms to operate new asset classes that demonstrate characteristics that are similar to our existing assets. We also plan to achieve growth by expanding our distribution capabilities to access a broader range of investment partners, thereby increasing our access to capital. This increased capital, when coupled with new investment opportunities, should increase our assets under management and the associated income as well as direct investment returns, thereby increasing shareholder value.

OUR CAPABILITIES

We believe that we have the necessary capabilities to execute our business strategy and achieve our performance targets. We focus on disciplined and active hands-on management of assets and capital. We strive for excellence and quality in each of our core operating platforms in the belief that this approach will produce superior returns over the long term.

We endeavour to operate as a value investor and follow a disciplined investment approach. Our management team has considerable capabilities in investment analysis, mergers and acquisitions, divestitures and corporate finance that enable us to acquire assets for value, finance them effectively, and to ultimately realize value created during our ownership.

Our operating platforms and depth of experience in managing these assets differentiate us from some competitors that have shorter investment horizons and more of a financial focus. Over time we have established a number of high quality operating platforms that are fully integrated into our organization. This has required considerable investment in building the management teams and the necessary resources; however, we believe these platforms enable us to optimize the cash returns and values of the assets that we manage.

We have established strong relationships with a number of leading institutions and believe we are well positioned to expand our sources of co-investment capital and clients. In order to expand our assets under management, we are investing in our distribution capabilities to encourage existing and potential clients to commit capital to our investment strategies. We are devoting expanded resources to these activities, and our efforts continue to be assisted by strong investment performance.

The diversification within our operations allows us to offer a broad range of products and investment strategies to our clients. We believe this is of considerable value to investors with large amounts of capital to deploy. In addition, our commitment to transparency and governance as a well capitalized public company listed on major North American and European stock exchanges better positions us as a strong long-term partner for our clients.

Finally, our commitment to invest considerable capital alongside our investors creates a strong alignment of interest between us and our investment partners and also differentiates us from many of our competitors. Accordingly, our strategy calls for us to maintain considerable surplus financial resources relative to other managers. This capital also supports our ability to commit to investment opportunities in anticipation of future syndications.

KEY PERFORMANCE FACTORS

Our ability to increase our operating cash flows is impacted by our ability to generate attractive returns on the capital invested on behalf of ourselves and our clients, and our ability to expand the magnitude of the capital that we manage on behalf of our clients. These two criteria are linked, in that the quality of our investment returns will encourage clients to commit capital to us, and our access to this capital will enable us to pursue a broader range of investment opportunities.

Investment returns are influenced by a number of factors that are specific to each asset and industry segment. There are however, four key activities that we focus on across the organization.

- Acquire assets “for value” meaning that the projected cash flows and value appreciation of the asset represent an attractive risk-adjusted return to ourselves and our co-investors.
- Optimize the cash returns and value of the asset on an ongoing basis. In most cases, this is the responsibility of one of our operating platforms, and is evidenced by the return on asset metrics and operating margins.
- Finance assets effectively, using a prudent amount of leverage. We believe this is very important in maximizing the net returns to investors from property and infrastructure assets, given the lower return on assets compared to a number of other businesses. Fortunately, these assets are well suited to support a relatively high level of investment grade secured debt given the predictability of the cash flows and tendency of these assets to retain substantial value throughout economic cycles. This is reflected in our return on net capital deployed, our overall return on capital and our cost of capital.
- Have the ability to realize the maximum value of assets through a direct or indirect sale or monetization of the assets. Many of our assets tend to appreciate in value over time and accordingly they may be held for very long periods of time. As a result, this “back-end” appreciation may not be recognized until there is a specific transaction.

Expanding our client relationships is impacted not only by our investment returns, as discussed above, but also by the quality of our distribution capabilities and by maintaining a high level of ongoing client service. This involves transparent and timely communication of results, ongoing engagement responsiveness to client objectives and generation of attractive investment opportunities.

FINANCIAL MEASURES

The long-term rate of growth of operating cash flow on a per share basis is our key performance measure. We also measure the cash return on equity, which demonstrates how effective we are at deploying the capital with which we have been entrusted by shareholders. Our current targets are 12% and 20%, respectively. We revisit these targets periodically in light of the current operating environment to ensure that they are realistic and can be achieved without exposing the organization to inappropriate risk.

The amount of co-investor capital commitments is also an important measure. One of our most important objectives is to significantly expand the amount of capital committed to us by our clients because this provides us with capital to expand our business and also entitles us to earn asset management income based on our ability to successfully invest this capital. “Third Party” asset management income is an important measure in that it is indicative of the cash flow generated from our asset management activities, which is an important source of growth in our operating cash flows.

Operating Cash Flow

We utilize operating cash flow (defined below under Terminology) as a key operating metric as opposed to net income, principally because operating cash flow does not include certain items that we believe can distort operations results, such as depreciation and amortization expense, and future income tax expense.

Depreciation as prescribed by GAAP, for example, implies these assets decline in value on a pre-determined basis over time, whereas we believe that the value of most of our assets, as long as regular sustaining capital expenditures are made, will typically increase over time. This increase in value will inevitably vary based on a number of market and other conditions that cannot be determined in advance, and may sometimes be negative in a particular period. Future income tax expense, in our case, is derived primarily from changes in the magnitude and quality of our tax losses and the differences between the tax values and book values of our assets, as opposed to current cash liabilities. Brookfield has access to significant tax shields as a result of the nature of our asset base, and we do not expect to incur any meaningful cash tax liability in the near future from ongoing operations.

Our operating cash flow is derived from two principal activities: asset management and operations. Our clients compensate us for asset management activities that we perform in respect of the capital and assets that we manage on their behalf. We also invest our own capital in most of the assets and capital that we manage for our clients, and accordingly participate in the operating cash flow produced by these assets and businesses and the associated value appreciation. Accordingly, we distinguish operating cash flows between those attributable to our asset management activities and those that represent investment returns from the capital deployed in established funds and directly held assets. Asset management activities include strategic oversight, investment analysis, capital allocation activities such as acquisitions, divestitures and financing, and the provision of specific services such as investment banking, facilities management and leasing.

Asset Management Income

Asset management income consists of base management fees, transaction fees and performance returns as well as additional property and investment banking services. The management agreements which govern these earnings vary from fund to fund. For example, base fees may be calculated based on net asset value, capital commitments, invested equity or total capital as defined in each agreement. Base management fees, therefore, represent stable long-term cash flows because they are paid over the life of a fund and contribute to income from the inception of the fund.

Our entitlement to performance returns is typically based on results over a prescribed measurement period, and any payments to us prior to the end of the period may be required to be returned if they exceed the actual amount determined at the end of the period (i.e. “clawed back”). We do not accrue any performance returns until such time as there is sufficient certainty that the amount recorded will not be impacted by future events, and therefore no longer subject to a clawback, even if such amounts are paid to us. Performance returns, by their nature, will tend to be more difficult to predict than base management fees. We believe, however, that the high quality and lower volatility of most of our assets should result in performance returns that are more stable than those recorded in respect of higher volatility investments.

Asset management income includes the fees that we receive from established funds, which will include fees in respect of the capital provided by our clients, which we refer to as “Third Party” fees, as well as any capital that we have invested in the funds. We also attribute fees to capital that is invested directly in assets that are not held in funds. This is an internal allocation that we establish by applying a fixed percentage fee to the estimated value of the operations.

We believe that it is important to consider the fees attributable to our capital in assessing the contribution from our different activities because it increases comparability and avoids distorting margins. This is particularly important as we continue to have a disproportionate amount of our own capital invested relative to client capital. For example, we incur expenses in providing asset management services in respect of all of our assets under management, including our own. If we were to eliminate the fees earned on our own capital, whether it is invested in established funds or directly owned assets, then we would be recognizing only a portion of the fees but all of the expenses. This results in distorted operating margins.

OPERATING ENVIRONMENT

Our operating performance is impacted by various factors that are specific to each of our operations as well as the specific sectors and geographic locations in which we operate. We are also impacted by macro-economic factors such as economic growth, changes in currency, inflation and interest rates, regulatory requirements and initiatives, and litigation and claims that arise in the normal course of business.

Our strategy is to invest in high quality long-life assets which generate sustainable streams of cash flow. While high quality assets may initially generate lower returns on capital, we believe that the sustainability and future growth of their cash flows is more

assured over the long term, and as a result, warrant higher valuation levels. We also believe that the high quality of our asset base protects the company against future uncertainty and enables us to invest with confidence when opportunities arise.

We discuss the risks associated with our business in detail in Part 4 – Business Environment and Risks beginning on page 41.

TERMINOLOGY

Operating Cash Flow

We define operating cash flow as net income prior to items such as depreciation and amortization, future income tax expense and certain non-cash items that in our view are not reflective of the actual underlying operations. Operating cash flow is a non-GAAP measure, and may differ from definitions of operating cash flow used by other companies. It is provided to investors as a consistent measurement tool which we believe assists in analysis of the company, in addition to other traditional measures, which we also provide. We recognize the importance of net income as a GAAP measure to investors and provide a full reconciliation between these measures.

“Total operating cash flow” represents the revenues less directly attributable operating costs.

“Net operating cash flow” represents the cash flow that is attributable to our net invested capital and is equal to total operating cash flow less financing costs associated with related liabilities and the interest of other investors in the operations.

Assets Under Management

Assets under management include assets managed by us on behalf of our clients, as well as our own assets. We invest capital alongside our clients in many of our funds, and we continue to own a number of assets that we acquired prior to the formation of our asset management operations and are therefore not part of any fund. Assets under management include the assets reflected in our consolidated financial statements and, as a result, are based on book values that may differ materially from current market values, particularly in the case of long-life assets that we have owned for many years as well as capital commitments that have not yet been drawn. Our calculation of assets under management may differ from that employed by other asset managers and, as a result, this measure may not be comparable to similar measures presented by other asset managers.

Co-investor Commitments

Co-investor commitments represent capital that has been committed to us to invest on behalf of the client. We typically earn base management fees on this capital from the time that the commitment to the fund is effective, during the period of time until the capital is invested (commonly referred to as the investment period) until such time as the investments are monetized and the capital returned to the client. Committed capital includes invested capital and commitments that have not yet been invested. Uninvested commitments represent capital available to us to invest and form part of our overall liquidity for these purposes.

Invested Capital

Invested capital represents the capital that Brookfield has invested through funds and directly. Consolidated assets represent the capital on a similar basis as our consolidated balance sheets. Net invested capital is presented on a de-consolidated basis, with the exception of Brookfield Properties, meaning that the assets are presented net of associated liabilities and non-controlling interests. We believe that net invested capital represents the most consistent basis of presentation and is how we assess the capital invested in our business. The consolidated basis is less meaningful, in our opinion, because certain of our operations and managed funds are consolidated and others are not.

Return on Invested Capital

We define cash return on capital as the operating cash flow per share as a percentage of the average book value per common share during the period, and for an individual operation as the operating cash flow as a percentage of the net invested capital. The numerator in calculating return on invested capital is our operating cash flow and the denominator is the average net book value over the measurement period.

PART 4 – BUSINESS ENVIRONMENT AND RISKS

The following is a review of certain risks that could adversely impact our financial condition, results of operation and the value of our common shares. Additional risks and uncertainties not previously known to the Corporation, or that the Corporation currently deems immaterial may also impact our operations and financial results.

GENERAL RISKS

We are exposed to the local, regional, national and international economic conditions and other events and occurrences that affect the markets in which we own assets and operate businesses. In general, a decline in economic conditions will result in downward pressure on our operating margins and asset values. We believe that the long life nature of our assets and, in many cases, the long-term nature of revenue contracts mitigates this risk to some degree.

Each segment of our business is subject to competition in varying degrees. This can result in downward pressure on revenues which can, in turn, reduce operating margins and thereby reduce operating cash flows and investment returns. In addition, competition could result in scarcity of inputs which can impact certain of our businesses through higher costs. We believe that the high quality and low operating costs of many of our assets and businesses provides some measure of protection in this regard.

A number of our long-life assets are interest rate sensitive: an increase in long-term interest rates will, absent all else, tend to decrease the value of the assets. We mitigate this risk in part by financing assets with long-term fixed rate debt, which will typically decrease in value as rates increase. In addition, we believe that many conditions that lead to higher interest rates, such as inflation, can also give rise to higher revenues which will, absent all else, tend to increase values.

The trading price of our common shares in the open market cannot be predicted. The trading price could fluctuate significantly in response to factors such as: variations in our quarterly or annual operating results and financial condition; changes in government regulations affecting our business; the announcement of significant events by our competitors; market conditions and events specific to the industries in which we operate; changes in general economic conditions; differences between our actual financial and operating results and those expected by investors and analysts; changes in analysts' recommendations or projections; the depth and liquidity of the market for our common shares; investor perception of our business and industry; investment restrictions; and our dividend policy. In addition, securities markets have experienced significant price and volume fluctuations in recent years that have often been unrelated or disproportionate to the operating performance of particular companies. These broad fluctuations may adversely affect the trading price of our common shares.

EXECUTION OF STRATEGY

Our strategy for building shareholder value is to acquire or develop high quality assets and businesses that generate sustainable and increasing cash flows on behalf of ourselves and co-investors, with the objective of achieving higher returns on invested capital and increasing asset management fees over the long term.

We consider effective capital allocation to be one of the most important components to achieving long-term investment success. As a result, we apply a rigorous approach towards the allocation of capital among our operations. Capital is invested only when the expected returns exceed pre-determined thresholds, taking into consideration both the degree and magnitude of the relative risks and upside potential and, if appropriate, strategic considerations in the establishment of new business activities.

The successful execution of a value investment strategy requires careful timing and business judgment, as well as the resources to complete asset purchases and restructure them as required, notwithstanding difficulties experienced in a particular industry. Our diversified business base, liquidity and the sustainability of our cash flows provide important elements of strength.

We endeavour to maintain an appropriate level of liquidity in order to invest on a value basis when attractive opportunities arise. Our approach to business entails adding assets to our existing businesses when the competition for assets is lowest, either due to depressed economic conditions or when concerns exist relating to a particular industry. However, there is no certainty that we will be able to acquire or develop additional high quality assets at attractive prices to supplement our growth. Conversely, overly favourable economic conditions can limit the number of attractive investment opportunities and thereby restrict our ability to increase assets under management and the related income streams. Competition from other well-capitalized investors may significantly increase the purchase price or prevent us from completing an acquisition. We may be unable to finance acquisitions on favourable terms, or newly acquired assets and businesses may fail to perform as expected. We may underestimate the costs necessary to bring an acquisition up to standards established for its intended market position or may be unable to quickly and efficiently integrate new acquisitions into our existing operations.

We develop property and power generation assets. In doing so, we must comply with extensive and complex regulations affecting the development process. These regulations impose on us additional costs and delays, which may adversely affect our business and results of operations. In particular, we are required to obtain the approval of numerous governmental authorities regulating matters such as permitted land uses, levels of density, the installation of utility services, zoning and building standards. We must comply with local, state and federal laws and regulations concerning the protection of health and the environment, including laws and regulations with respect to hazardous or toxic substances. These environmental laws and regulations sometimes result in delays, which cause us to incur additional costs, or severely restrict development activity in environmentally sensitive regions or areas.

Our ability to successfully expand our asset management business is dependent on our reputation with our current and potential investment partners. We believe that our track record and recent investments, as well as adherence to operating principles that emphasize a constructive management culture, will enable us to continue to develop productive relationships with institutional investors. However, competition for institutional capital, particularly in the asset classes on which we focus, is intense. Although we seek to differentiate ourselves there is no assurance that we will be successful in doing so and this competition may reduce the margins of our asset management business and may decrease the extent of institutional investor involvement in our activities.

Our executive and other senior officers have a significant role in our success. Our ability to retain our management group or attract suitable replacements should any members of the management group leave is dependent on the competitive nature of the employment market. The loss of services from key members of the management group or a limitation in their availability could adversely impact our financial condition and cash flow. Further, such a loss could be negatively perceived in the capital markets. The conduct of our business and the execution of our growth strategy rely heavily on teamwork. Co-operation amongst our operations and our team-oriented management structure are essential to responding promptly to opportunities and challenges as they arise. We believe that our hiring and compensation practices encourage retention and teamwork.

We participate in joint ventures, partnerships, co-tenancies and funds affecting many of our assets and businesses. Investments in partnerships, joint ventures, co-tenancies or other entities may involve risks not present were a third party not involved, including the possibility that our partners, co-tenants or co-venturers might become bankrupt or otherwise fail to fund their share of required capital contributions. Additionally, our partners, co-venturers or co-tenants might at any time have economic or other business interests or goals. In addition, we do not have sole control of certain major decisions relating to these assets and businesses, including: decisions relating to the sale of the assets and businesses; refinancing; timing and amount of distributions of cash from such entities to the Corporation; and capital expenditures.

Some of our management arrangements permit our partners to terminate the management agreement in limited circumstances relating to enforcement of the managers' obligations. In addition, the sale or transfer of interests in some of our entities is subject to rights of first refusal or first offer and some agreements provide for buy-sell or similar arrangements. Such rights may be triggered at a time when we may not want to sell but may be forced to do so because we may not have the financial resources at that time to purchase the other party's interest. Such rights may also inhibit our ability to sell our interest in an entity within our desired time frame or on any other desired basis.

FINANCIAL AND LIQUIDITY RISKS

We employ debt and other forms of leverage in the ordinary course of our business in order to enhance returns to shareholders and our co-investors. We attempt to match the profile of the leverage to the associated assets and accordingly fund shorter duration floating rate assets with shorter term floating rate debt and fund long-term fixed rate and equity like assets with long-term fixed rate and equity capital. Most of the debt within our business has recourse only to the assets or subsidiary being financed and has no recourse to the Corporation.

Accordingly, we are subject to the risks associated with debt financing. These risks, including the following, may adversely affect our financial condition and results of operations: our cash flow may be insufficient to meet required payments of principal and interest; payments of principal and interest on borrowings may leave us with insufficient cash resources to pay operating expenses; we may not be able to refinance indebtedness on our assets at maturity due to company and market factors including: the estimated cash flow of our assets; the value of our assets; liquidity in the debt markets; financial, competitive, business and other factors, including factors beyond our control; and if refinanced, the terms of a refinancing may not be as favourable as the original terms of the related indebtedness. We structure our financings to mitigate these risks through the use of long-term debt and by diversifying our maturities over an extended period of time. We also strive to maintain adequate liquidity to refinance obligations.

The terms of our various credit agreements and other indebtedness require us to comply with a number of customary financial and other covenants, such as maintaining debt service coverage and leverage ratios and maintaining insurance coverage. These covenants may limit our flexibility in our operations, and breaches of these covenants could result in defaults under the instruments governing the applicable indebtedness even if we had satisfied our payment obligations.

If we are unable to refinance our indebtedness on acceptable terms, or at all, we may need to dispose of one or more of our assets upon disadvantageous terms, prevailing interest rates or other factors at the time of refinancing could increase our interest expense, and if we pledge assets to secure payment of indebtedness and are unable to make required payments, the creditor could foreclose upon such asset or appoint a receiver to receive an assignment of the associated cash flows.

A large proportion of our capital is invested in physical assets such as office properties, hydroelectric power generating facilities and transmission systems which can be hard to sell, especially if local market conditions are poor. Such liquidity could limit our ability to vary our portfolio or assets promptly in response to changing economic or investment conditions. Additionally, financial or operating difficulties of other owners resulting in distress sales could depress asset values in the markets in which we operate in times of illiquidity. These restrictions could reduce our ability to respond to changes in the performance of our investments and market conditions and could adversely affect our financial condition and results of operations.

We periodically enter into agreements that commit us to acquire assets or securities. In some cases we may enter into such agreements with the expectation that we will syndicate or assign all or a portion of our commitment to other investors prior to, at the same time as, or subsequent to the anticipated closing. We may be unable to complete this syndication or assignment which may increase the amount of capital that we are required to invest. These activities can have an adverse impact on our liquidity which may reduce our ability to pursue further acquisitions or meet other financial commitments.

We enter into financing commitments in the normal course of business and, as a result, may be required to fund these. Although we do not typically do so, we from time to time guarantee the obligations of funds or other entities that we manage and/or invest in. If we are unable to fulfill any of these commitments this could result in damages being pursued against us or a loss of opportunity through default of contracts that are otherwise to our benefit.

Our business is impacted by changes in currency rates, interest rates, commodity prices and other financial exposures. As a general policy, we endeavour to maintain balanced positions, although unmatched positions may be taken from time to time within pre-determined limits. The company's risk management and derivative financial instruments are more fully described in the notes to our Consolidated Financial Statements. We selectively utilize financial instruments to manage these exposures.

We have pursued and intend to continue to pursue growth opportunities in international markets and often invest in countries where the U.S. dollar is not the notional currency. As a result, we are subject to foreign currency risk due to potential fluctuations in exchange rates between foreign currencies and the U.S. dollar. A significant depreciation in the value of the foreign currency of one or more countries where we have a significant investment may have a material adverse effect on our results of operations and financial position. Although we attempt to maintain a hedged position with respect to the carrying value of net assets denominated in currencies other than the U.S. dollar, this is not always possible or economical to do. Even if we do so, the carrying value may not equal the economic value, meaning that any difference may not be hedged. In addition, the company receives certain cash flows that are denominated in foreign currencies that are not hedged. We mitigate adverse effects by borrowing under debt agreements denominated in foreign currencies and through the use of financial contracts, however, there can be no assurance that those attempts to mitigate foreign currency risk will be successful.

We typically finance assets that generate predictable long-term cash flows with long-term fixed rate debt in order to provide stability in cash flows and protect returns in the event of changes in interest rates. We also make use of fixed rate preferred equity financing as well as financial contracts to provide additional protection in this regard. Similarly, we typically finance shorter term floating rate assets with floating rate debt. Historically, the company and our subsidiaries have tended to maintain a net floating rate liability position because we believe that this results in lower financing costs over the long term although in recent years we have maintained a net floating rate asset position given our view on interest rates.

As at December 31, 2007, our net floating rate liability position was \$0.2 billion (2006 – asset of \$0.9 billion). As a result, a 10 basis point increase in interest rates would increase operating cash flow by \$16 million, or \$0.03 per share. Our fixed-rate obligations at year end include a notional amount of \$1.6 billion (2006 – \$1.1 billion) which we are required to record at market value and any

changes in value recorded as current income, with the result that a 10 basis point increase in long-term interest rates will result in a corresponding increase in income of \$13 million before tax or \$0.02 per share and vice versa, based on our year end positions. It is important for shareholders to keep in mind that these interest rate related revaluation gains or losses are offset by corresponding changes in values of the assets and cash flow streams that they relate to, which are not reflected in current income.

We selectively utilize credit default swaps and equity derivatives to hedge financial positions and may establish unhedged positions from time to time. These instruments are typically utilized as an alternative to purchasing or selling the underlying security when they are more effective from a capital employment perspective.

COMMERCIAL OFFICE PROPERTIES

Our strategy is to invest in high quality commercial office properties as defined by the physical characteristics of the assets and, more importantly, the certainty of receiving rental payments from large corporate tenants which these properties attract. Nonetheless, we remain exposed to certain risks inherent in the core office property business.

Core office property investments are generally subject to varying degrees of risk depending on the nature of the property. These risks include changes in general economic conditions (such as the availability and cost of mortgage funds), local conditions (such as an oversupply of space or a reduction in demand for real estate in markets in which we operate), the attractiveness of the properties to tenants, competition from other landlords and our ability to provide adequate maintenance at an economical cost.

Certain significant expenditures, including property taxes, maintenance costs, mortgage payments, insurance costs and related charges, must be made regardless of whether or not a property is producing sufficient income to service these expenses. Our core office properties are subject to mortgages which require substantial debt service payments. If we become unable or unwilling to meet mortgage payments on any property, losses could be sustained as a result of the mortgagee's exercise of its rights of foreclosure or of sale. We believe the stability and long-term nature of our contractual revenues is an effective mitigant to these risks.

Our core office properties generate a relatively stable source of income from contractual tenant rent payments. We endeavour to stagger our lease expiry profile so that we are not faced with a disproportionate amount of space expiring in any one year. Continued growth of rental income is dependent on strong leasing markets to ensure expiring leases are renewed and new tenants are found promptly to fill vacancies. While we believe the outlook for commercial office rents is positive for both 2008 and in the longer term, it is possible that rental rates could decline or that renewals may not be achieved. The company is, however, substantially protected against short-term market conditions, since most of our leases are long-term in nature. A protracted disruption in the economy, such as the onset of a severe recession, could place downward pressure over time on overall occupancy levels and net effective rents.

RESIDENTIAL PROPERTIES

In our residential land development and homebuilding operations, markets have been favourable over most of the past seven years. Our operations are concentrated in high growth areas which we believe have positive long-term demographic and economic conditions. Despite this, over the past 18 months the U.S. market has seen extremely negative market sentiment towards housing and has similarly affected our operations in the U.S.

The residential homebuilding and land development industry is cyclical and is significantly affected by changes in general and local economic conditions, such as consumer confidence, employment levels, availability of financing for homebuyers and interest rates. Competition from rental properties and used homes may depress prices and reduce margins for the sale of new homes. Homebuilders are also subject to risks related to the availability and cost overruns. Furthermore, the market value of undeveloped land, buildable lots and housing inventories held by us can fluctuate significantly as a result of changing economic and real estate market conditions. If there are significant adverse changes in economic or real estate market conditions, we may have to sell homes at a loss or hold land in inventory longer than planned. Inventory carrying costs can be significant and can result in losses in a poorly performing project or market. Our residential property operations may be particularly affected by changes in local market conditions in California, Virginia, Alberta and Brazil where we derive a large proportion of our residential property revenue. During 2007, we recorded approximately \$100 million of charges against our U.S. revenues to reflect changing conditions.

Many of our customers finance their home acquisitions through lenders providing mortgage financing. Mortgage rates have recently been at or near their lowest levels in many years. Despite this, and given that dramatic issues being experienced in the sub-prime markets in the U.S. and by many lenders, it has become more difficult for borrowers to procure mortgages.

Even if potential customers do not need financing, changes in interest rates and mortgage availability could make it harder for them to sell their homes to potential buyers who need financing, which in the U.S. has resulted in reduced demand for new homes. As a result, rising mortgage rates could adversely affect our ability to sell new homes and the price at which we can sell them.

POWER GENERATING OPERATIONS

Our strategy is to own primarily hydroelectric generating facilities, which have operating costs significantly below that of most competing forms of generation. As a result, there is a high level of assurance that we will be able to deliver power on a profitable basis. In addition, we sell most of our generation pursuant to contracts that protect us from variations in future prices. Nonetheless, we are subject to certain risks, the most significant of which are hydrology and price, but also include changes in regulation, risk of increased maintenance costs, dam failure and other disruptions.

The revenues generated by our power facilities are proportional to the amount of electricity generated, which is dependent upon available water flows. Although annual deviations from long-term average water flows can be significant, we strive to mitigate this risk by increasing the geographic diversification of our facilities which assists in balancing the impact of generation fluctuations in any one geographic region.

Demand for electricity varies with economic activity. An economic slowdown could have an adverse impact on prices. In addition, oversupply in our markets may result from excess generating capacity. Pricing risk is mitigated through fixed-price contracts and forward sales of electricity. Future pricing levels are dependent on economic and supply conditions and the terms on which contracts are renewed. A portion of our power generation revenue is tied, either directly or indirectly, to the spot market price for electricity. Electricity price volatility could have a significant effect on our business, operating results, financial condition or prospects.

There is a risk of equipment failure due to, among other things, wear and tear, latent defect, design error or operator error which could adversely affect revenues and cash flows. Although the power systems have operated in accordance with expectations, there can be no assurance that they will continue to do so. In the future, our generation assets may require significant capital expenditures and operations could be exposed to unexpected increases in costs such as labour, water rents and taxes. Nevertheless, this risk is substantially mitigated by the proven nature of hydroelectric technology, the design of the plants, capital programs, adherence to prudent maintenance programs, comprehensive insurance and significant operational flexibility as a result of having generating units which can operate independently.

The operation of hydroelectric generating facilities and associated sales of electricity are regulated to varying degrees in most regions. Changes in regulation can affect the quantity of generation and the manner in which we produce it.

The occurrence of dam failures at any of our hydroelectric generating stations could result in a loss of generating capacity and repairing such failures could require us to incur significant expenditures of capital and other resources. Such failures could result in us being exposed to liability for damages. There can be no assurance that our dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of failure. Upgrading all dams to enable them to withstand all events could require us to incur significant expenditures of capital and other resources.

The occurrence of a significant event which disrupts the ability of our generation assets to produce or sell power for an extended period, including events which preclude existing customers from purchasing electricity, could have a material negative impact on the business. Our generation assets could be exposed to effects of severe weather conditions, natural disasters and potentially catastrophic events such as a major accident or incident at our generation facilities. In addition, many of our generation assets are located in remote areas which makes access for repair of damage difficult.

TIMBERLANDS

The financial performance of our timberland operations depends on the state of the lumber and pulp and paper industries. Decreases in the level of residential construction activity generally reduce demand for logs and wood products, resulting in lower revenues, profits and cash flows for lumber mills who are important customers to us. Depressed commodity prices of lumber, pulp or paper or market irregularities may cause mill operators to temporarily or permanently shut down their mills if their product prices fall to a level where mill operation would be uneconomic. Any of these circumstances could significantly reduce the prices that we realize for our timber and the amount of timber that such operators purchase from us.

Weather conditions, timber growth cycles, access limitations, aboriginal claims and regulatory requirements associated with forestry practices, sale of logs and environmental matters, may restrict our harvesting, as may other factors, including damage by fire, insect infestation, disease, prolonged drought and other natural and man-made disasters. Although management believes it follows best practices with regard to forest sustainability and general forest management, there can be no assurance that our forest management planning, including silviculture, will have the intended result of ensuring that our asset base appreciates in value over time. If management's estimates of merchantable inventory are incorrect, harvesting levels on our timberlands may result in depletion of our timber assets.

TRANSMISSION INFRASTRUCTURE

Our transmission operations are subject to regulation. The regulated rates are designed to recover allowed costs, including debt financing costs, and permit earning a specified rate of return on assets or equity. Any changes in the rate structure for the transmission assets or any reallocation or redetermination of allowed costs relating to the transmission assets, could have a material adverse effect on our transmission revenues and operating margins.

SPECIALTY INVESTMENT FUNDS

Our specialty funds operations are focused on the ownership and management of securities and businesses that are supported by underlying tangible assets and cash flows. The principal risks in this business are potential loss of invested capital as well as insufficient investment or fee income to cover operating expenses and cost of capital.

Unfavourable economic conditions could have a significant impact on the value and liquidity of our investments and the level of investment income. Since most of our investments are in our areas of expertise and given that we strive to maintain adequate supplemental liquidity at all times, we are well positioned to assume ownership of and operate most of the assets and businesses that we finance. Furthermore, if this situation does arise, we typically acquire the assets at a discount to the underwritten value, which protects us from loss.

OTHER RISKS

As an owner and manager of real property, we are subject to various federal, provincial, state and municipal laws relating to environmental matters. These laws could hold us liable for the costs of removal and remediation of certain hazardous substances or wastes released or deposited on or in our properties or disposed of at other locations. The failure to remove or remediate such substances, if any, could adversely affect our ability to sell our real estate or to borrow using real estate as collateral, and could potentially result in claims or other proceedings against us. We are not aware of any material non-compliance with environmental laws at any of our properties. We are also not aware of any material pending or threatened investigations or actions by environmental regulatory authorities in connection with any of our properties or any material investigations or actions by environmental regulatory authorities in connection with any of our properties or any material pending threatened claims relating to environmental conditions at our properties. We have made and will continue to make the necessary capital expenditure for compliance with environmental laws and regulations. Environmental laws and regulations can change rapidly and we may become subject to more stringent environmental laws and regulations in the future. Compliance with more stringent environmental laws and regulations could have an adverse effect on our business, financial condition or results of operation.

The ownership and operation of our assets carry varying degrees of inherent risk of liability related to worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to contravention of health, safety and environmental laws, licenses, permits and other approvals, and potential civil liability. Compliance with health, safety and environmental laws (and any future laws or amendments enacted) and the requirements of licenses, permits and other approvals will remain material to our business. We have incurred and will continue to incur significant capital and operating expenditures

to comply with health, safety and environmental laws and to obtain and comply with licenses, permits and other approvals and to assess and manage its potential liability exposure. Nevertheless, from time to time it is possible that we may be unsuccessful in obtaining an important license, permit or other approval or become subject to government orders, investigations, inquiries or other proceedings (including civil claims) relating to health, safety and environmental matters. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licenses, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures. As a consequence, no assurance can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to its business and operations.

Our core office portfolio is concentrated in large metropolitan areas, some of which have been or may be perceived to be subject to terrorist attacks. Furthermore, many of our properties consist of high-rise buildings, which may also be subject to this actual or perceived threat, which could be heightened in the event that the United States continues to engage in armed conflict. This could have an adverse effect on our ability to lease office space in our portfolio. Each of these factors could have an adverse impact on our operating results and cash flows. Our core office property operations have insurance covering certain acts of terrorism for up to \$500 million of damage and business interruption costs. We continue to seek additional coverage equal to the full replacement cost of our assets; however, until this type of coverage becomes commercially available on a reasonably economic basis, any damage or business interruption costs as a result of uninsured acts of terrorism could result in a material cost to the company.

We carry various insurance coverages that provide comprehensive protection for first party and third party losses to our properties. These coverages contain policy specifications, limits and deductibles customarily carried for similar properties. We also self-insure a portion of certain of these risks. We believe all of our properties are adequately insured.

There are certain types of risks (generally of a catastrophic nature such as war or environmental contamination such as toxic mold) which are either uninsurable or not economically insurable. Should any uninsured or underinsured loss occur, we could lose our investment in, and anticipated profits and cash flows from, one or more of our assets or operations, and would continue to be obligated to repay any recourse mortgage indebtedness on such properties.

In the normal course of our operations, we become involved in various legal actions, typically involving claims relating to personal injuries, property damage, property taxes, land rights and contract disputes. We endeavour to maintain adequate provisions for outstanding or pending claims. The final outcome with respect to outstanding, pending or future actions cannot be predicted with certainty, and therefore there can be no assurance that their resolution will not have an adverse effect on our financial position or results of our operations in a particular quarter or fiscal year. We believe that we are not currently involved in any litigation, claims or proceedings in which an adverse outcome would have a material adverse effect on our consolidated financial position or results.

Ongoing changes to the physical climate in which we operate may have an impact on our business. In particular, changes in weather patterns may impact hydrology levels thereby influencing generation levels and power generation levels. Climate change may also give rise to changes in regulations and consumer sentiment that could impact other areas of our business.

The U.S. Investment Company Act of 1940 (the "Act") requires the registration of any company which holds itself out to the public as being engaged primarily in the business of investing, reinvesting or trading in securities. In addition, the Act may also require the registration of a company that is engaged or proposes to engage in the business of investing, reinvesting, owning, holding or trading in securities and which owns or proposes to acquire investment securities with a value of more than 40% of the company's assets on an unconsolidated basis. We are not currently an investment company in accordance with the Act and we believe we can continue to arrange our business operations in ways so as to avoid becoming an investment company within the meaning of the Act. If we were required to register as an investment company under the Act, we would, among other things, be restricted from engaging in certain businesses and issuing certain securities. In addition, certain of our contracts may become void.

There are many other laws and governmental regulations that apply to us, our assets and businesses. Changes in these laws and governmental regulations, or their interpretation by agencies or the courts, could occur. Further, economic and political factors, including civil unrest, governmental changes and restrictions on the ability to transfer capital across borders in the United States, but primarily in the foreign countries in which we have invested, can have a major impact on us as a global company.

A portion of the workforce in our operations is unionized and if we are unable to negotiate acceptable contracts with any of our unions as existing agreements expire, we could experience a significant disruption of the affected operations, higher ongoing labour costs and restriction of its ability to maximize the efficiency of its operations, which could have an adverse effect on our operations and financial results.

PART 5 – DESCRIPTION OF OPERATING PLATFORMS

In this section we provide supplemental information on each of our principal operating platforms as well as our private equity investments.

COMMERCIAL PROPERTIES

We own and operate commercial office and retail properties on behalf of ourselves and our co-investors in North America, South America, Europe, Australia and the Middle East.

Office Properties

We own and manage one of the highest quality commercial office portfolios in the world and focus on major financial, energy and government centre cities in North America, Australasia and Europe. Our strategy is to concentrate our operations in high growth, supply-constrained markets that have high barriers to entry and attractive tenant bases. Our goal is to maintain a meaningful presence in each of our primary markets so as to build on the strength of our tenant relationships.

Our North American operations are conducted through a 51%-owned subsidiary, Brookfield Properties, and our primary markets are New York, Boston, Houston, Los Angeles, Washington D.C., Toronto, Calgary and Ottawa. These operations include directly owned properties as well as those contained within our U.S. and Canadian core office funds.

Our European operations are principally located in London, U.K. where we own an interest in 17 high quality commercial properties comprising 8.5 million square feet of rentable area and a further 5.4 million square feet of development density. The properties are located in the Canary Wharf Estate, one of the leading core office developments in Europe. We hold a direct 100% ownership interest in the 550,000 square foot 20 Canada Square property and an indirect interest in the balance of the portfolio through our 15% ownership interest in privately-owned Canary Wharf Group.

We acquired a high quality portfolio in Australia and New Zealand in late 2007 through our acquisition of Multiplex, consisting of 24 commercial properties containing 6.2 million square feet of net leasable area.

Office property assets under management totalled \$29 billion at the end of 2007, of which \$17 billion are held directly and \$12 billion are held through seven funds with aggregate capital commitments of \$3.7 billion.

Portfolio Activity

The following table sets out the assets and capital in our commercial property operations at the end of 2007 and 2006. Our property assets are recorded at depreciated book value, which in most cases are significantly below recent market values. In particular, the consolidated carrying value of our North American properties is approximately \$272 per square foot, significantly less than the estimated replacement cost of these assets.

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
	2007	2006	2007	2006	Consolidated Assets		Net Invested Capital	
	2007	2006	2007	2006	2007	2006	2007	2006
North America								
United States	\$ 14,348	\$ 14,304	\$ 1,025	\$ 1,069	\$ 13,593	\$ 13,189	\$ 13,593	\$ 13,189
Canada	4,541	4,392	650	648	2,391	2,209	2,391	2,209
	18,889	18,696	1,675	1,717	15,984	15,398	15,984	15,398
United Kingdom	796	765	—	—	796	765	787	747
Australasia	5,728	—	623	—	3,198	—	3,198	—
Total properties	25,413	19,461	2,298	1,717	19,978	16,163	19,969	16,145
Other assets	3,639	853	—	—	3,639	853	3,639	853
Other liabilities							(2,275)	(919)
Property-specific mortgages							(16,183)	(11,811)
Co-investors' capital							(450)	(523)
	\$ 29,052	\$ 20,314	\$ 2,298	\$ 1,717	\$ 23,617	\$ 17,016	\$ 4,700	\$ 3,745

Our total portfolio occupancy rate at the end of 2007 was 96% across our portfolios worldwide compared to 95% at December 31, 2006 as set forth in the following table:

	2007			2006		
	Total Area	Owned Interest	Percentage Leased	Total Area	Owned Interest	Percentage Leased
<i>AS AT DECEMBER 31 (THOUSANDS)</i>						
Core North American markets						
United States	46,703	42,477	94%	46,080	40,794	94%
Canada	19,827	10,131	99%	23,067	11,252	98%
Other North American	6,648	5,958	95%	6,648	5,958	93%
United Kingdom	8,500	2,173	97%	8,500	2,173	94%
Australasia	8,463	6,185	99%	—	—	—
Total ¹	90,141	66,924	96%	84,295	60,177	95%

¹ Excludes development sites

As at December 31, 2007, the average term of our in-place leases in North America was seven years and annual expiries average 7.1% over the next five years. The U.S. portfolio acquired in late 2006 had a shorter lease maturity than the balance of our portfolio, which we will seek to extend as we re-lease the properties.

Leasing fundamentals in London also continued to improve, bringing total occupancy across the portfolio to more than 97%, with an average unexpired lease term of approximately 20 years. Nearly 80% of the tenant rating profile is A+ or better.

Property-specific mortgages and other debt secured by our commercial property interests includes \$1.6 billion of debt associated with the Multiplex acquisition in 2007 and \$2.7 billion of assumed debt. The loan to value for the Multiplex acquisition debt and assumed debt represents a relatively conservative loan to value of less than 65%.

During the year we refinanced a number of properties in Europe and North America. This included the refinancing of One Liberty Plaza through the issuance of \$850 million, 6.1% mortgage debt, replacing \$400 million of existing debt. This enabled us to monetize a portion of the value created in this property in recent years and enhance our return on capital. Core office property debt at December 31, 2007 had an average interest rate of 7% and an average term to maturity of seven years. The co-investors' capital represents the 38% interest of our partners in the U.S. Core Office fund.

Other assets include rents receivable and working capital balances as well as a portion of the purchase price of property that has been attributed to items such as above-market leases and tenant relationships. Similarly, other liabilities include \$1 billion in respect of items such as below-market tenant and land leases.

Retail Properties

We operate the Brascan Brasil Real Estate Partners fund which was formed in late 2006 and has \$800 million of committed capital (Brookfield's share – 25%). We completed a number of acquisitions which enabled us to fully invest the fund with \$1.7 billion of total assets within 18 months from inception and establishes us as one of the largest owners of retail centres in Brazil. The fund's portfolio now consists of interests in 15 shopping centres and associated office space totalling 4.7 million square feet of net leasable area, located primarily in Rio de Janeiro and São Paulo.

	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
					Consolidated Assets		Net Invested Capital	
AS AT DECEMBER 31 (MILLIONS)	2007	2006	2007	2006	2007	2006	2007	2006
Retail properties	\$ 1,698	\$ 800	\$ 600	\$ 600	\$ 1,698	\$ 215	\$ 827	\$ 207
Borrowings							(462)	(105)
Co-investors' capital							(262)	(74)
Net investment	\$ 1,698	\$ 800	\$ 600	\$ 600	\$ 1,698	\$ 215	\$ 103	\$ 28

The book value of retail properties includes total and net working capital balances of \$209 million (2006 – \$46 million) and \$54 million (2006 – \$38 million), respectively as well as \$716 million representing a portion of the portfolio purchase price. Borrowings also include \$265 million of debt incurred by the fund to finance the purchase of the initial portfolio assets, which is guaranteed by the obligations of ourselves and our partners to subscribe for capital in the fund up to the level of the committed amounts.

POWER GENERATING OPERATIONS

We own one of the largest privately owned hydroelectric power generating portfolios in the world. We are currently exploring alternatives to establish an externally managed entity through which we can share the ownership of these assets with others on a fee-bearing basis.

Our power generating operations are predominantly hydroelectric facilities located on river systems in the U.S., Canada and Brazil. As at December 31, 2007, we owned and managed 160 power generating stations with a combined generating capacity of approximately 3,900 megawatts. Our facilities produced approximately 13,000 gigawatt hours of electricity in 2007. All but four of our existing stations are hydroelectric facilities located on river systems in seven geographic regions, specifically Ontario, Quebec, British Columbia, New York, New England, Louisiana and southern Brazil. This geographic distribution provides diversification of water flows to minimize the overall impact of fluctuating hydrology. Our storage reservoirs contain sufficient water to produce approximately 20% of our total annual generation and provide partial protection against short-term changes in water supply. The reservoirs also enable us to optimize selling prices by generating and selling power during higher-priced peak periods. We also own and operate two natural gas-fired plants, a pumped storage facility and a 189-megawatt wind energy project that we operate under a 20-year fixed price power sales agreement.

Financial Position

Total assets in the segment increased to \$6.8 billion from \$5.4 billion at the end of last year due to the acquisition and development of power facilities as well as the impact of increases in the carrying value of non-U.S. assets as a result of currency fluctuation. Financings completed during the year enabled us to maintain the net capital invested in this segment at approximately \$1.4 billion.

	Capacity		Assets Under Management		Brookfield Invested Capital			
	2007	2006	2007	2006	Consolidated		Net	
AS AT DECEMBER 31 (MILLIONS)					2007	2006	2007	2006
Hydroelectric generation	(MW)							
Ontario	897	897	\$ 1,269	\$ 1,094	\$ 1,269	\$ 1,094	\$ 1,269	\$ 1,094
Quebec	277	277	434	371	434	371	434	371
British Columbia	134	127	172	133	172	133	172	133
New England	240	240	397	400	397	400	397	400
New York and other northeast markets	852	832	1,046	1,016	1,046	1,016	1,046	1,016
Louisiana	192	192	459	478	459	478	459	478
Brazil	295	205	522	264	522	264	522	264
Total hydroelectric generation	2,887	2,770	4,299	3,756	4,299	3,756	4,299	3,756
Wind energy	189	189	369	327	369	327	369	327
Co-generation and pumped storage	815	815	233	166	233	166	233	166
Development projects	—	—	236	60	236	60	236	60
Total power generation	3,891	3,774	5,137	4,309	5,137	4,309	5,137	4,309
Cash, financial assets, accounts receivable and other			1,665	1,081	1,665	1,081	1,665	1,081
Accounts payable and other liabilities			—	—	—	—	(879)	(419)
Property-specific and subsidiary debt			—	—	—	—	(4,285)	(3,388)
Non-controlling interests in net assets			—	—	—	—	(213)	(215)
	3,891	3,774	\$ 6,802	\$ 5,390	\$ 6,802	\$ 5,390	\$ 1,425	\$ 1,368

Property-specific debt totalled \$3.5 billion at December 31, 2007 and corporate unsecured notes issued by our power generating operations totalled \$0.8 billion. Property-specific debt has an average interest rate of 7% and an average term of 13 years and is all investment grade quality. The corporate unsecured notes bear interest at an average rate of 5%, have an average term of 9 years and are rated BBB by S&P and BBB (high) by DBRS and BBB by Fitch.

Contract Profile

Approximately 77% of our projected 2008 and 2009 generation is currently subject to long-term bilateral power sales agreements or shorter-term financial contracts. The remaining generation is sold into wholesale electricity markets. Our long-term sales contracts, which cover approximately 53% of total generation during this period, have an average term of 13 years and the counterparties are

almost exclusively customers with long-standing favourable credit histories or investment grade ratings. The financial contracts typically have a term of less than three years.

The following table sets out the profile of our contracts over the next five years from our existing facilities, assuming long-term average hydrology:

	<i>Years ended December 31</i>				
	<i>2008</i>	<i>2009</i>	<i>2010</i>	<i>2011</i>	<i>2012</i>
Generation (GWh)					
Contracted					
Power sales agreements	7,874	6,497	6,465	6,004	5,934
Financial contracts	3,169	3,376	287	—	—
Uncontracted	2,732	3,364	6,467	7,221	7,284
	13,775	13,237	13,219	13,225	13,218
Contracted generation					
% of total	80	75	51	45	45
Revenue (\$millions)	797	741	530	495	496
Price (\$/MWh)	72	75	78	83	84

The increase in the average selling price for contracted power from \$72 per megawatt hour (MWh) to \$84 per MWh over the next five years reflects contractual step-ups in long duration contracts with attractive locked-in prices and the expiry of lower priced contracts during the period. In addition, a number of contracts for our non-U.S. facilities have benefitted from favourable currency appreciation.

INFRASTRUCTURE

Our infrastructure activities are currently concentrated in the timber and electricity transmission sectors, however we are actively reviewing a number of opportunities to expand into new sectors that provide similar investment characteristics. These operations are owned directly and through entities that we manage.

Timberlands

We manage 2.5 million acres of high quality private timberlands with an aggregate book value of \$3 billion. We manage a listed specialty issuer that operates in eastern North America and a private fund named Island Timberlands that operates on the west coast of Canada. These funds have aggregate equity capital of \$594 million, of which our share is \$278 million. We also own direct interests in \$2 billion of timberlands in the Pacific Northwest and Brazil. We recently announced the formation of a \$250 million Brazil timber fund.

In January 2008 we transferred 30% of our Pacific Northwest operations and a 37.5% interest in Island Timberlands to Brookfield Infrastructure.

Operating Results

	<i>Operating Cash Flow</i>			
	<i>Total</i>		<i>Net</i>	
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>	<i>2007</i>	<i>2006</i>	<i>2007</i>	<i>2006</i>
Timber				
Western North America				
Timberlands	\$ 123	\$ 59		
Higher and better use lands	7	6		
Eastern North America	20	18		
Brazil	8	4		
Timberlands	158	87	\$ 158	\$ 87
Interest expense			(85)	(29)
Non-controlling interests in net assets			(33)	(26)
	\$ 158	\$ 87	\$ 40	\$ 32

Portfolio Activity and Financial Position

AS AT DECEMBER 31 (\$MILLIONS)	Acres	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
		2007	2006	2007	2006	Consolidated Assets		Net Invested	
		2007	2006	2007	2006	2007	2006	2007	2006
Timber									
Western North America									
Timberlands	1,186,650	\$ 2,603	\$ 777	\$ 243	\$ 240	\$ 2,603	\$ 777	\$ 2,603	\$ 777
Higher and better use lands	32,865	105	111	—	—	105	111	105	111
Eastern North America	1,076,000	185	189	72	100	185	189	185	189
Brazil	180,000	66	45	—	—	66	45	66	45
	2,475,515	2,959	1,122	315	340	2,959	1,122	2,959	1,122
Other assets, net		716	68	—	—	716	68	74	18
		3,675	1,190	315	340	3,675	1,190	3,033	1,140
Property-specific and other borrowings								(1,691)	(485)
Co-investors' capital								(317)	(340)
		\$ 3,675	\$ 1,190	\$ 315	\$ 340	\$ 3,675	\$ 1,190	\$ 1,025	\$ 315

We acquired Longview Fibre Company, which owns 588,000 acres of high quality timberlands located in the U.S. Pacific Northwest during the second quarter of 2007. Total invested capital includes the purchase cost of the timberlands of \$1.9 billion, together with goodwill and working capital totalling \$2.6 billion. We recorded a future tax obligation of \$593 million relating to the difference between the amount paid by us for the company and the tax basis of the underlying assets. The inclusion of this liability in the net book value of the acquired business gave rise to goodwill of \$593 million. We expect that we will be able to reorganize the ownership structure of the business over time such that we can extinguish the tax liability without any material cash outlay. Net invested capital includes the net capital invested by us in Longview's timber operations after taking into consideration debt raised to finance the acquisition and the future tax liabilities and subsequent asset sales.

As at December 31, 2007, borrowings included approximately \$1.2 billion associated with the Longview acquisition that is secured by the underlying timber assets in North America. The Longview debt consists of an 18-month bridge facility that is in the process of being refinanced with a long-term fixed rate financing secured by the associated timberlands. Our western Canadian timberlands secure investment grade borrowings of approximately \$410 million, which have an average interest rate of 6%, and an average term to maturity of 16 years. The balance of the borrowings consists of debt secured by the eastern Canadian timber assets and working capital facilities.

Non-controlling interests represent the interests of co-investors in our two North American funds. We currently own 50% of our western Canadian fund and 45% of Acadian.

Transmission

Our electricity transmission operations consist of the largest transmission system in Chile, a smaller system in northern Ontario and interests in transmission lines in Brazil. We own 28% of the Chilean operations and provide management advisory services to our investment partners on a fee-for-service basis, 100% of the northern Ontario operations and an effective 20% interest in the Brazil operations.

We transferred our northern Ontario and Brazil interests to Brookfield Infrastructure, as well as a 17% interest in the Chilean operations. We believe the regulated rate base nature of these assets provides for attractive reliable long-term returns and we will endeavour to expand our operations in this asset class.

Portfolio Activity and Financial Position

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital		Consolidated Assets		Net Invested Capital	
	2007	2006	2007	2006	2007	2006	2007	2006	2007	2006
Transmission facilities and investments										
Chile	\$ 2,650	\$ 2,525	\$ 877	\$ 831	\$ 330	\$ 2,525	\$ 330	\$ 2,525	\$ 330	\$ 2,525
North America	193	146			193	146	193	146	193	146
Brazil	205	157			205	157	205	157	205	157
	3,048	2,828			728	2,828	728	2,828	728	2,828
Other assets	32	315			32	315	32	315	32	315
	3,080	3,143			760	3,143	760	3,143	760	3,143
Other liabilities									(26)	(267)
Project-specific financing and other borrowings									(114)	(1,496)
									620	1,380
Co-investors' capital									—	(831)
	\$ 3,080	\$ 3,143	\$ 877	\$ 831	\$ 760	\$ 3,143	\$ 620	\$ 549		

Net invested capital was relatively unchanged during the year, although consolidated assets declined as we no longer consolidate the assets and liabilities of our Chilean operations. These operations are financed with property-specific financing borrowings totalling \$1.5 billion that have an average interest rate of 6%, an average term to maturity of 11 years and are predominantly investment grade.

DEVELOPMENT AND OTHER PROPERTIES

Opportunity Investments

We operate niche real estate opportunity funds with \$417 million of committed capital (Brookfield's share – \$258 million).

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital		Consolidated Assets		Net Invested Capital	
	2007	2006	2007	2006	2007	2006	2007	2006	2007	2006
Commercial properties	\$ 1,571	\$ 1,086	\$ 159	\$ 116	\$ 1,571	\$ 1,086	\$ 1,280	\$ 1,055	\$ 1,280	\$ 1,055
Property-specific mortgages							(934)	(820)	(934)	(820)
Co-investors' capital							(121)	(103)	(121)	(103)
	\$ 1,571	\$ 1,086	\$ 159	\$ 116	\$ 1,571	\$ 1,086	\$ 225	\$ 132	\$ 225	\$ 132

Total property assets within the fund were approximately \$1.6 billion at year end, an increase of \$0.5 billion from the end of 2006, due to the completion of a major portfolio acquisition. The portfolio consists of approximately 124 properties, predominantly office properties in a number of cities across North America as well as smaller investments in industrial, student housing, multi-family, and other property asset classes. The book value of commercial properties increased due to acquisitions during the year, offset in part by property sales. Our net invested capital at December 31, 2007 included a \$42 million bridge loan to the fund (2006 – \$23 million), and \$52 million of direct capital in addition to our base commitment that was provided to fund acquisitions.

Residential Properties

We conduct residential property operations in Canada, the United States and Brazil through public subsidiaries in which we hold the following interests: Canada – 51%; United States – 58%; Brazil – 60%. We recently formed a land joint venture with \$400 million of committed capital from a U.S. institution and ourselves that we will manage.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Assets Under Management	Invested Capital				Operating Cash Flow			
		Total		Net		Total		Net	
	2007	2007	2006	2007	2006	2007	2006	2007	2006
United States	\$ 1,384	\$ 1,384	\$ 1,355	\$ 1,224	\$ 1,142	\$ 46	\$ 236		
Canada	516	516	305	516	305	237	144		
Brazil	1,009	1,009	743	612	567	92	36		
	2,909	2,909	2,403	2,352	2,014	375	416	\$ 375	\$ 416
Impairment charge – U.S.						(103)	—	(103)	—
Borrowings / interest ¹				(1,363)	(1,126)			(18)	(23)
Cash taxes								18	(93)
Non-controlling interest in net assets				(539)	(404)			(12)	(69)
				450	484	272	416	260	231
Realization gain				—	—		269	—	269
Net investment / operating cash flow	\$ 2,909	\$ 2,909	\$ 2,403	\$ 450	\$ 484	\$ 272	\$ 685	\$ 260	\$ 500

¹ Portion of interest expressed through cost of sales

Total assets, which include property assets as well as inventory, cash and cash equivalents and other working capital balances, have increased since 2006 due to the impact of currency appreciation on our capital in Canada and Brazil, and as new capital was invested to match sales growth in Canada. Subsidiary borrowings consist primarily of construction financings which are repaid with the proceeds from sales of building lots, single-family houses and condominiums and is generally renewed on a rolling basis as new construction commences.

Under Development

Properties under development include both active development projects as well as properties that we are redeveloping to enhance their value.

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Brookfield Invested Capital			
	2007	2006	Consolidated Assets		Net Invested Capital	
	2007	2006	2007	2006	2007	2006
Commercial properties						
North America	\$ 965	\$ 551	\$ 965	\$ 551	\$ 965	\$ 551
Australia and United Kingdom	2,072	—	2,072	—	2,072	—
Brazil	162	107	162	107	162	107
Residential lots						
Australia	201	—	201	—	201	—
Property-specific financing	—	—	—	—	(1,704)	(240)
	\$ 3,400	\$ 658	\$ 3,400	\$ 658	\$ 1,696	\$ 418

In addition to the properties listed above, we have been actively developing a number of hydroelectric power facilities in Brazil and North America, as well as wind generation facilities in Canada, which are described further under Power Generation Operations.

Current development initiatives in North America are focused on the construction of a 1.1 million square foot premier office property on the Bay Adelaide Centre site located in Toronto's downtown financial district, representing a book value of \$416 million (2006 – \$251 million), the redevelopment of the 1.3 million square foot Four Allen Center in Houston carried at \$198 million (2006 – \$139 million) and properties in Washington, D.C.

We significantly expanded our development activities with the acquisition of Multiplex which has 70 commercial projects underway that will contain over 20 million square feet and approximately 18,000 residential lots, homes and units. We also own our proportionate share of the approximate 5.4 million square feet of commercial space development density at Canary Wharf in London of which 1.3 million is currently under active development.

Property-specific financing includes debt secured by Bay Adelaide Centre and Four Allen Cedar in North America as well as debt associated with developments in Australia and the United Kingdom that was assumed on the acquisition of Multiplex.

Held for Development

We acquire land or long-term rights on land, seek entitlements to construct, and then either sell the project once it has been improved or build the project ourselves. We typically hold these projects directly, given that they do not generate current cash flow, until the project is completed, at which time it can be transferred to an existing fund portfolio or sold outright. Accordingly, we do not typically record ongoing cash flow in respect of properties held for development and the associated development costs are capitalized until this event occurs, at which time any disposition gain or loss is realized.

AS AT DECEMBER 31 (MILLIONS)	Brookfield Invested Capital			
	Consolidated Assets		Net Invested Capital	
	2007	2006	2007	2006
Commercial office properties				
Ninth Avenue, New York	\$ 207	\$ 184	\$ 207	\$ 184
Residential lots				
Canada and Brazil	804	516	804	516
Rural development				
Brazil	190	66	159	49
	\$ 1,201	\$ 766	\$ 1,170	\$ 749

Commercial Office Properties

We own well-positioned land at Ninth Avenue between 31st Street and 33rd Street in New York city. We intend to commence construction of the necessary infrastructure to enable the subsequent construction of 5.4 million square feet of commercial office space once the necessary pre-leasing has occurred.

Residential Development Properties

Residential development properties include land, both owned and optioned, which is in the process of being converted to residential lots, but not expected to enter the homebuilding process for more than three years. We utilize options to control lots for future years in our higher land cost markets in order to reduce risk. To that end, we hold options on approximately 12,300 lots which are located predominantly in California and Virginia. We invested additional capital into development land in Alberta as a result of the significant increase in activity in this market.

Rural Development Properties

We own approximately 372,000 acres of prime rural development land in the States of São Paulo, Minas Gerais and Mato Grosso, having acquired a number of new properties in 2007. These properties are being used for agricultural purposes, including the harvest of sugar cane for its use in the production of ethanol as a gasoline substitute. We also hold 33,300 acres of potentially higher and better use land adjacent to our western North American timberlands, which we intend to convert into residential and other purpose land over time, and are included within our timberlands segment.

SPECIALTY FUNDS

We conduct bridge lending, restructuring and real estate finance activities. Although our primary industry focus is on property, power and long-life infrastructure assets, our mandates within our bridge finance and restructuring funds include other industries which have tangible assets and cash flows, and particularly where we have expertise as a result of previous investment experience. As at December 31, 2007 we managed nine funds with total committed capital of \$5 billion and total assets under management of \$7 billion.

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
	2007	2006	2007	2006	Consolidated Assets		Net Invested	
	2007	2006	2007	2006	2007	2006	2007	2006
Bridge lending	\$ 1,187	\$ 1,452	\$ 1,510	\$ 470	\$ 488	\$ 637	\$ 488	\$ 622
Restructuring	1,538	977	753	652	1,538	977	361	377
Real estate finance	4,637	5,438	1,225	937	685	183	263	183
Real estate services	125	—	59	59	25	—	25	—
	\$ 7,487	\$ 7,867	\$ 3,547	\$ 2,118	\$ 2,736	\$ 1,797	\$ 1,137	\$ 1,182

Bridge Lending

We operate three bridge lending funds. Our first fund has commitments of \$1.2 billion at the end of the year, of which \$0.9 billion is funded and will mature through 2011. We have \$0.6 billion committed to these funds. We have raised C\$935 million in commitments and pledges for our two follow-on funds, consisting of a senior and junior fund, and includes a C\$240 million commitment from Brookfield. We have advanced \$105 million of loans within the new funds thus far.

We had total assets under management of \$1.2 billion at year end, down from \$1.5 billion at the end of 2006. The level of committed capital to our funds from clients increased to \$1.5 billion at year end due to the formation of new funds during the year. Our net invested capital was \$488 million, down from \$622 million at the end of 2006. The decline in invested capital occurred primarily during the fourth quarter of 2007 as a result of a number of maturities.

Our portfolio at year end was comprised of 16 loans, and our largest single exposure at that date was \$105 million. Our share of the portfolio has an average term of 20 months excluding extension privileges and generates an average yield of 14% based on interest rate levels at year end.

Restructuring

We operate two restructuring funds. Our first fund, Tricap Restructuring Fund ("Tricap I") completed its investment period last year and we continue to manage and harvest the remaining invested capital of \$432 million. We also completed an additional capital raise for Tricap Partners II ("Tricap II"), which now has \$842 million of committed capital. The capital committed by us to both funds totals \$521 million, including co-investment capital invested by us in Tricap I.

Our two principal investments in Tricap I are Western Forest Products and Concert Industries. Western Forest Products experienced a difficult year due in part to a major industry strike which has since been resolved. Concert Industries, a leading producer of air-laid woven fabric, continues to perform well and we continue to make progress expanding its revenue and operating base.

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Co-investor Commitments		Brookfield Invested Capital			
	2007	2006	2007	2006	Consolidated Assets		Net Invested	
	2007	2006	2007	2006	2007	2006	2007	2006
Property, plant and equipment	\$ 615	\$ 453			\$ 615	\$ 453	\$ 615	\$ 453
Securities	115	29			115	29	115	29
Loans receivable	51	23			51	23	51	23
Other assets	757	472			757	472	757	472
	1,538	977			1,538	977	1,538	977
Other liabilities							(433)	(235)
Subsidiary debt							(293)	(175)
Non-controlling interests							(451)	(190)
	\$ 1,538	\$ 977	\$ 753	\$ 652	\$ 1,538	\$ 977	\$ 361	\$ 377

Our net invested capital in restructuring opportunities at year end was \$361 million, relatively unchanged from the end of 2006.

Real Estate Finance

We operate three real estate finance funds with total committed capital of approximately \$1.6 billion, of which our share is approximately \$400 million. Our first private fund, the \$600 million Brookfield Real Estate Finance Partners (BREF I) recently completed its investment period and we completed a \$450 million capital raise for our second fund (BREF II). We also manage a public mortgage REIT that is listed on the NYSE and has raised \$565 million of equity capital.

During 2007, BREF I acquired investments with an aggregate principal balance of approximately \$1.1 billion and concluded its investment period. During 2007, BREF II commenced its investment period and completed investments with an aggregate principal balance of approximately \$460 million. The portfolio continues to perform in line with expectations notwithstanding difficult credit markets.

ADVISORY SERVICES

We manage fixed income and real estate securities and provide investment banking services, all with a particular focus on property and infrastructure.

We manage \$26.2 billion of fixed income and equity securities on an advisory basis for a large number of institutional and individual investors. The largest proportion of these assets is managed by our New York-based Brookfield Hyperion Group, which specializes in real estate fixed income securities. We acquired Chicago-based K.G. Redding Inc., (now known as Brookfield Redding), in late 2007. Brookfield Redding has a well established record as a leading real estate equity securities manager with a wide variety of clients throughout North America and Australasia. Brookfield Soundvest, based in Ottawa, Canada, manages fixed income and equity securities on behalf of a number of Canadian institutional investors.

AS AT DECEMBER 31 (MILLIONS)	Assets Under Management	
	2007	2006
Brookfield Hyperion	\$ 20,210	\$ 19,711
Brookfield Redding	5,325	—
Brookfield Soundvest	702	749
	\$ 26,237	\$ 20,460

Our investment banking services are provided by teams located in Canada and Brazil.

PRIVATE EQUITY INVESTMENTS

We own a number of investments which will be sold once value has been maximized, integrated into our core operations or used to seed new funds. Although not core to our broader strategy, we expect to continue to make new investments of this nature and dispose of more mature assets.

AS AT DECEMBER 31 (MILLIONS)	Location	Interest	Assets Under Management 2007	Brookfield Invested Capital			
				Consolidated		Net	
				2007	2006	2007	2006
Forest products							
Norbord Inc.	North America / UK	27%	\$ 180	\$ 180	\$ 178	\$ 19	\$ 26
Fraser Papers Inc.	North America	56%	477	477	141	109	141
Privately held	North America	100%	162	162	140	113	95
Infrastructure							
Coal lands	Alberta	100%	85	85	73	85	73
Business services							
Insurance	Various	80-100%	2,513	2,513	2,357	661	593
Banco Brascán, S.A.	Rio de Janeiro	—	—	—	75	—	75
Privately held	Various	100%	229	229	369	223	278
Publicly listed	Canada	60%	52	52	51	26	23
Property							
Privately held	Brazil	Various	153	153	66	100	100
Net investment			\$ 3,851	\$ 3,851	\$ 3,450	\$ 1,336	\$ 1,404

We account for our non-controlled public investments where we exercise significant influence, such as Norbord, using the equity method, and include dividends received from these investments in operating cash flow and our proportional share of their earnings in net income. We consolidate the results of our majority owned private companies and accordingly include our proportional share of their results in the operating cash flow shown above.

Forest Products

We control 41% and own a net beneficial interest in approximately 27% or 40 million shares of Norbord Inc. ("Norbord"). Net invested capital reflects debentures issued by us that are exchangeable into 20 million Norbord shares and which are recorded at the market value of the Norbord shares. Our net investment had a market value of approximately \$319 million at year end.

Privately held forest products operations include paper and pulp operations that we acquired out of bankruptcy in April 2003 in connection with the purchase of power generation operations.

Infrastructure

We own the coal rights under approximately 475,000 acres of freehold lands in central Alberta. These lands supply approximately 11% of Alberta's coal-fired power generation through the production of approximately 13 million tonnes of coal annually. Royalties from this production generate \$6 million of operating cash flow and provide a stable source of income as they are free of crown royalties. In addition, we own a 3.5% net profit interest in 75 million tonnes of proven reserves, and 35 million tonnes of potential reserves of high quality metallurgical coal in British Columbia.

Business Services

Our insurance operations are conducted through 80%-owned Imagine Insurance, a specialty reinsurance business which operates internationally; Hermitage Insurance, a property and casualty insurer which operates principally in the northeast United States; and Trisura, a surety company based in Toronto. We manage the securities portfolios of these companies, which total \$1.6 billion and consist primarily of highly rated government and corporate bonds, through our public securities operations. Imagine is rated A- and A- (excellent) by Fitch and AM Best, respectively and Hermitage is rated B++ (good) by AM Best. We continue to explore a variety of options to surface the value of our insurance business, which could result in a reduced ownership interest in the future.

We acquired control of Banco Brascan during the year and have integrated the book values associated with their investment banking, lending and capital markets activities with our corresponding activities.

CASH AND FINANCIAL ASSETS

We hold a substantial amount of financial assets, cash and equivalents that represent liquid capital to fund operating activities and investment initiatives. We reduced our holdings during the year to capture value appreciation in the face of increasingly volatile markets and to fund operating activities.

AS AT DECEMBER 31 (MILLIONS)	Assets Under Management	Brookfield Invested Capital			
	2007	Total 2007	2006	Net 2007	2006
Financial assets					
Government bonds	\$ 420	\$ 420	\$ 57	\$ 420	\$ 57
Corporate bonds – Exchangeable debentures	—	—	375	—	375
– Other	286	286	199	286	199
Fixed income	22	22	16	22	16
High yield bonds	112	112	137	112	137
Preferred shares	40	40	26	40	26
Common shares – Multiplex	—	—	44	—	44
– Other	51	51	504	51	504
Loans receivable	76	76	10	76	10
Total financial assets	1,007	1,007	1,368	1,007	1,368
Cash and cash equivalents	360	360	305	360	305
Deposits and other liabilities	—	—	—	(500)	(524)
Net investment	\$ 1,367	\$ 1,367	\$ 1,673	\$ 867	\$ 1,149

During 2007, we adopted new accounting guidelines related to financial instruments under which our financial assets, other than equity accounted investments and most loans receivable, are carried at fair values. The December 31, 2006 balances are shown at original cost other than designated trading portfolios that are carried at market.

As part of our ongoing risk management and value creation activities, we also establish market positions using total return swaps and credit derivatives. As at December 31, 2007, we maintain common equity positions with a notional value of \$70 million through total return swaps. We also bought protection against spread widening through credit default swaps with a total notional value of \$2.4 billion, which have a limited downside and benefit from increases in credit spreads and defaults of the underlying debt.

Deposit and other liabilities include broker deposit liabilities associated with our securities portfolio and borrowed securities sold short with a value of \$39 million at December 31, 2007.

PART 6 – CAPITAL RESOURCES AND LIQUIDITY

The following sections describe our capitalization and liquidity profile on both a consolidated and deconsolidated basis. The strength of our capital structure and the liquidity that we maintain enables us to achieve a low cost of capital for our shareholders and at the same time provides us with the flexibility to react quickly to potential investment opportunities as they arise, as well as to withstand sudden adverse changes in economic circumstances.

Our primary sources of liquidity consist of our cash and financial assets, net of deposits and other associated liabilities, and undrawn committed credit facilities. These total \$2.0 billion at December 31, 2007, compared with \$2.1 billion as at December 31, 2006. Furthermore, we endeavour to structure our invested capital in a manner that enables future monetization of our investments as desired.

CAPITALIZATION

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Cost of Capital ¹ 2007	Book Value				Operating Cash Flow ²			
		Consolidated		Net Invested Capital		Total		Net	
		2007	2006	2007	2006	2007	2006	2007	2006
Corporate borrowings	7%	\$ 2,048	\$ 1,507	\$ 2,048	\$ 1,507	\$ 146	\$ 126	\$ 146	\$ 126
Non-recourse borrowings									
Property-specific mortgages	7%	21,644	17,148	—	—	1,226	751	—	—
Subsidiary borrowings ³	7%	7,463	4,153	711	668	324	212	66	64
Other liabilities	9%	11,102	6,497	3,148	1,771	532	475	450	320
Capital securities	6%	1,570	1,585	1,570	1,585	90	96	90	96
Non-controlling interest in net assets	20%	4,256	3,734	1,773	1,829	636	468	368	247
Shareholders' equity									
Preferred equity	5%	870	689	870	689	44	35	44	35
Common equity	20%	6,644	5,395	6,644	5,395	1,863	1,766	1,863	1,766
	9.5%	\$ 55,597	\$ 40,708	\$ 16,764	\$ 13,444	\$ 4,861	\$ 3,929	\$ 3,027	\$ 2,654

¹ Based on operating cash flows as a percentage of average book value

² Interest expense in the case of borrowings. Attributable operating cash flows in the case of minority and equity interests, including cash distributions. Current taxes and operating expenses in the case of accounts payable and other liabilities

³ Net amounts represent subsidiary obligations guaranteed by the Corporation or issued by corporate subsidiaries

Our overall weighted average cash cost of capital, using a 20% return objective for our common equity, is 9.5%, unchanged from 2006. This reflects the low cost of non-participating perpetual preferred equity issued over a number of years, as well as the low cost of term debt, capital securities and non-recourse investment grade financings, achievable due to the high quality of our core office properties and power generating plants.

Corporate Borrowings

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Cost of Capital ¹		Book Value				Operating Cash Flow ²			
	2007	2006	Total		Net		Total		Net	
			2007	2006	2007	2006	2007	2006	2007	2006
Commercial paper and bank borrowings	6%	5%	\$ 167	\$ —	\$ 167	\$ —	\$ 26	\$ 11	\$ 26	\$ 11
Publicly traded term debt	7%	7%	1,881	1,463	1,881	1,463	118	113	118	113
Privately held term debt ³	—	6%	—	44	—	44	2	2	2	2
	7%	7%	\$ 2,048	\$ 1,507	\$ 2,048	\$ 1,507	\$ 146	\$ 126	\$ 146	\$ 126

¹ As a percentage of average book value of debt

² Interest expense

³ \$44 million is secured by coal assets included in Investments

The average interest rate on our corporate borrowings was 7% at year end, similar to 2006, and the average term was 11 years (2006 – 11 years).

The Corporation has \$1,395 million of committed corporate four-year revolving term credit facilities which are utilized principally as back-up credit lines to support commercial paper issuance. At December 31, 2007, \$167 million of these facilities were drawn, and approximately \$63 million (2006 – \$43 million) of the facilities were utilized for letters of credit issued to support various business initiatives.

Non-Recourse Borrowings

As part of our financing strategy, we raise the majority of our debt capital in the form of asset-specific mortgages or subsidiary obligations. With limited exceptions, these obligations have no recourse to the Corporation.

The nature of these borrowings is discussed within the Operating Platforms section as part of the relevant business unit reviews.

Property-Specific Borrowings

Where appropriate, we finance our operating assets with long-term non-recourse borrowings that have no recourse to the Corporation or our operating entities, such as property-specific mortgages and project financings.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Average Term	Cost of Capital ¹		Brookfield Invested Capital				Operating Cash Flow ²			
				Total		Net		Total		Net	
		2007	2006	2007	2006	2007	2006	2007	2006	2007	2006
Commercial properties	6	7%	7%	\$ 16,360	\$ 12,470	\$ —	\$ —	\$ 834	\$ 465	\$ —	\$ —
Power generation	13	7%	8%	3,488	2,704	—	—	248	206	—	—
Infrastructure	6	7%	6%	1,796	1,974	—	—	144	80	—	—
	7	7%	7%	\$ 21,644	\$ 17,148	\$ —	\$ —	\$ 1,226	\$ 751	\$ —	\$ —

¹ As a percentage of average book value

² Interest expense

Commercial property debt includes \$2.8 billion of mortgage financing assumed with our acquisition of Multiplex which has no recourse to the Corporation. The remaining increase relates principally to our North American office property operations and reflects financings for new and existing properties, including a new 10-year \$850 million mortgage on One Liberty Plaza in downtown Manhattan that replaced an existing \$400 million mortgage at lower rates. The increase also reflects the impact of currency fluctuations on non-U.S. debt.

Property-specific financings within our power operations increased by approximately \$800 million due to a \$330 million financing secured by hydroelectric facilities in New York State and currency appreciation on financings securing facilities in Brazil and Canada.

During the year, we completed a \$1.2 billion financing within our infrastructure operations to fund the acquisition of our Pacific Northwest timberland operations. The debt is secured by these operations and has no recourse to the Corporation. We are in the process of refinancing this debt with long-term fixed rate financing. Consolidated debt declined by a similar amount as we no longer consolidate our Chilean transmission operations beginning June 30, 2007.

Other Debt of Subsidiaries

These borrowings are largely corporate debt of subsidiaries, issued by way of corporate bonds, bank credit facilities, commercial paper and other financial obligations of subsidiaries.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Average Term	Cost of Capital ¹		Brookfield Invested Capital				Operating Cash Flow ²			
				Total		Net		Total		Net	
		2007	2006	2007	2006	2007	2006	2007	2006	2007	2006
Subsidiary borrowings											
Properties	2	7%	7%	\$ 3,806	\$ 1,111	\$ —	\$ —	\$ 55	\$ 37	\$ —	\$ —
Power generation	9	5%	5%	797	684	—	—	41	29	—	—
Private equity investments	2	7%	5%	1,387	298	—	—	79	44	—	—
Corporate subsidiaries	7	10%	10%	711	668	711	668	66	64	66	64
Co-investor capital											
Properties	6	10%	11%	762	803	—	—	55	12	—	—
Infrastructure	—	—	9%	—	589	—	—	28	26	—	—
	4	7%	7%	\$ 7,463	\$ 4,153	\$ 711	\$ 668	\$ 324	\$ 212	\$ 66	\$ 64

¹ As a percentage of average book value

² Interest expense

Properties debt includes \$1.6 billion of debt incurred to complete the Multiplex acquisition as well as \$0.4 billion of debt within that company that has no recourse to the Corporation.

Infrastructure debt at December 31, 2006 related to our Chilean transmission operations, which are no longer consolidated into our financial results.

Private equity investments' debt increased due to the consolidation of Fraser Papers and Banco Brascan during 2007.

Other debt of subsidiaries include C\$127 million retractable preferred shares issued by corporate subsidiaries that are fully integrated into our ownership structure as well as financial obligations that are guaranteed by the Corporation. The company does not typically guarantee the debts of subsidiaries, with the principal exception being a guarantee of subsidiary debt due in 2015 which was originally issued in 1990, and was assumed by the Corporation upon amalgamating with the original guarantor.

Capital Securities

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Average Term	Cost of Capital ¹		Brookfield Invested Capital				Operating Cash Flow ²			
		2007	2006	Total 2007	2006	Net 2007	2006	Total 2007	2006	Net 2007	2006
Corporate preferred shares	7	6%	6%	\$ 517	\$ 663	\$ 517	\$ 663	\$ 32	\$ 44	\$ 32	\$ 44
Subsidiary preferred shares	7	6%	6%	1,053	922	1,053	922	58	52	58	52
	7	6%	6%	\$ 1,570	\$ 1,585	\$ 1,570	\$ 1,585	\$ 90	\$ 96	\$ 90	\$ 96

¹ As a percentage of average book value

² Interest expense

Distributions paid on these securities, which are largely denominated in Canadian dollars, are recorded as interest expense, even though all of the issues are preferred shares that are convertible into common equity at our option. The holders of the preferred shares also have the right, after a fixed date, to convert the shares into common equity based on the market price of our common shares at that time and, accordingly, these securities are classified as liabilities for Canadian GAAP purposes.

The average distribution yield on the capital securities at December 31, 2007 was 6% (2006 – 6%) and the average term was 7 years (2006 – 12 years). We have been issuing lower cost perpetual preferred equity with more favourable terms and using the proceeds to redeem certain capital securities. To that end, we redeemed C\$125 million of 8.35% capital securities due 2050 in January 2007 and a further C\$125 million, 8.30% capital securities in July 2007.

Interests of Co-investors in Net Assets

Interests of co-investors in net assets are comprised of two components: participating interests of other shareholders in our operating assets and subsidiary companies, and non-participating preferred equity issued by subsidiaries.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Number of Shares / % Interest 2007	Brookfield Invested Capital				Operating Cash Flow ¹			
		Total		Net		Total		Net	
		2007	2006	2007	2006	2007	2006	2007	2006
Participating interests									
Property									
Brookfield Properties Corporation	198.3 / 49%	\$ 1,622	\$ 1,633	\$ 1,622	\$ 1,633	\$ 361	\$ 243	\$ 361	\$ 243
Brookfield Homes Corporation	11.1 / 42%	245	174	—	—	(16)	69	—	—
Property funds and other	various	843	601	—	—	157	8	—	—
Power generation	various	170	203	—	—	47	42	—	—
Infrastructure									
Timberlands	50% / 55%	314	338	—	—	33	26	—	—
Transmission	—	—	242	—	—	5	(6)	—	—
Other	various	911	347	—	—	42	82	—	—
		4,105	3,538	1,622	1,633	629	464	361	243
Non-participating interests		151	196	151	196	7	4	7	4
		\$ 4,256	\$ 3,734	\$ 1,773	\$ 1,829	\$ 636	\$ 468	\$ 368	\$ 247

¹ Represents share of operating cash flows attributable to the interests of the respective shareholders and includes cash distributions

We include Brookfield Properties on a fully consolidated basis in our segmented basis of presentation and accordingly the interests of others in these operations are reflected in both the total and net results. The other entities shown above are presented on a deconsolidated basis in our segmented analysis, and, as a result, the interests of other shareholders are presented in total invested capital and total operating cash flow only. These interests are discussed as appropriate within each of the operating segments. The total operating cash flow attributable to these interests is shown as a deduction in arriving at the net operating cash flow for each respective business unit.

Operating cash flow distributed to other non-controlling shareholders in the form of cash dividends totalled \$169 million (\$110 million on a net basis) in 2007 compared with \$147 million (\$85 million on a net basis) for the same period in 2006. The undistributed cash flows attributable to non-controlling shareholders are retained in the respective operating businesses and are available to expand their operations, reduce indebtedness or repurchase equity.

Preferred Equity

Preferred equity represents perpetual floating rate preferred shares that provide an attractive form of permanent equity leverage to our common shares.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Cost of Capital ¹		Brookfield Invested Capital				Operating Cash Flow ²			
			Total		Net		Total		Net	
	2007	2006	2007	2006	2007	2006	2007	2006	2007	2006
Preferred equity	5%	6%	\$ 870	\$ 689	\$ 870	\$ 689	\$ 44	\$ 35	\$ 44	\$ 35

¹ As a percentage of average book value

² Dividends

We issued C\$200 million of 4.75% perpetual preferred shares during the second quarter, in addition to an issue of an equivalent amount and terms in late 2006.

Common Equity

On a diluted basis, Brookfield had 611.0 million common shares outstanding at year end with an aggregate book value of \$6.6 billion or \$11.64 per share. The market capitalization of our common shares on December 31, 2007 was \$22.3 billion or \$35.67 per share. The difference of \$15.7 billion (2006 – \$14.5 billion) reflects in part the appreciation in the value of our assets that is not reflected in our book values due to accounting depreciation and economic appreciation, and acquisitions that were completed at a discount to long-term value.

The number of shares outstanding increased by 0.2 million shares on a diluted basis during 2007. We repurchased 4.9 million common shares under issuer bids at an average price of \$33 per share, issued 3.5 million options in connection with annual compensation awards, and issued 1.8 million common shares in connection with an acquisition.

Brookfield has two classes of common shares outstanding: Class A and Class B. Each class of shares elects one-half of the Corporation's Board of Directors. The Class B shares are held by Partners Ltd., a private company owned by 42 individuals, including a number of the senior executive officers of Brookfield, who also collectively hold direct and indirect beneficial interests in approximately 100 million Class A shares representing an approximate 17% equity interest in the company. Further details on Partners Ltd. can be found in the company's management information circular.

OTHER ASSETS AND LIABILITIES

Other Assets

The following is a summary of other assets:

AS AT DECEMBER 31 (MILLIONS)	Net Invested Capital	
	2007	2006
Accounts receivable	\$ 565	\$ 386
Restricted cash	184	517
Intangible assets	211	130
Prepaid and other assets	788	888
Deferred tax asset	262	—
	\$ 2,010	\$ 1,921

Other assets include working capital balances employed in our business that are not directly attributable to specific operating units. The magnitude of these balances varies somewhat based on seasonal variances. The net balances include \$1,171 million (2006 – \$846 million) associated with Brookfield Properties and \$839 million (2006 – \$1,075 million) associated with the Corporation.

Other Liabilities

AS AT DECEMBER 31 (MILLIONS)	Brookfield Invested Capital			
	Total		Net	
	2007	2006	2007	2006
Accounts payable	\$ 3,659	\$ 1,778	\$ 1,130	\$ 952
Insurance liabilities	1,655	1,619	—	—
Deferred tax liability	1,523	436	1,044	349
Other liabilities	4,265	2,664	974	470
	\$ 11,102	\$ 6,497	\$ 3,148	\$ 1,771

Accounts payable and other liabilities include \$1,398 million associated with Brookfield Properties (2006 – \$616 million). Deferred taxes represent future tax obligations that arise largely due to holding assets whose book value exceeds their value for tax purposes. The increase in these balances on a total basis since year end relate primarily to the difference between our purchase cost of Longview Fibre and the underlying tax basis of the acquired assets. We expect to be able to restructure our ownership of this business so that the accounting liability will not give rise to any material cash outlay.

LIQUIDITY

We attempt to maintain sufficient financial liquidity at all times so that we are able to participate in attractive investment opportunities as they arise, and to also better withstand sudden adverse changes in economic circumstances. Our principal sources of liquidity are financial assets, undrawn committed credit facilities, free cash flow and the turnover of assets on our balance sheet. We structure the ownership of our assets to enhance our ability to monetize their embedded value to provide additional liquidity if necessary.

Our free cash flow represents the operating cash flow retained in the business after operating costs and cash taxes, interest payments, dividend payments to other shareholders of consolidated entities, preferred equity distributions and sustaining capital expenditures. This cash flow is available to pay common share dividends, invest for future growth, reduce borrowings or repurchase equity.

Maturity Profile of Debt Obligations

We endeavour to finance our long-term assets with long-term financing and to diversify our principal repayments over a number of years. Principal repayments on debt obligations due over the next five years and thereafter are as follows:

Corporate Borrowings

YEARS ENDED DECEMBER 31 (MILLIONS)	Average Term	2008	2009	2010	2011	2012	Beyond	Total
Commercial paper and bank borrowings	2	\$ 117	\$ 17	\$ 17	\$ 16	\$ —	\$ —	\$ 167
Publicly traded term debt	11	299	—	199	—	346	1,037	1,881
Total	11	\$ 416	\$ 17	\$ 216	\$ 16	\$ 346	\$ 1,037	\$ 2,048
Percentage of total		20%	1%	10%	1%	17%	51%	100%

Property-Specific Borrowings

YEARS ENDED DECEMBER 31 (MILLIONS)	Average Term	2008	2009	2010	2011	2012	Beyond	Total
Commercial properties	6	\$ 2,950	\$ 1,678	\$ 211	\$ 4,685	\$ 423	\$ 5,479	\$ 15,426
Power generation	13	55	138	161	88	667	2,379	3,488
Infrastructure	6	1,200	42	—	32	—	522	1,796
Development and other properties		131	499	182	2	62	58	934
Total	7	\$ 4,336	\$ 2,357	\$ 554	\$ 4,807	\$ 1,152	\$ 8,438	\$ 21,644
Percentage of total		20%	11%	3%	22%	5%	39%	100%

Other Debt of Subsidiaries

YEARS ENDED DECEMBER 31 (MILLIONS)	Average Term	2008	2009	2010	2011	2012	Beyond	Total
Subsidiary borrowings								
Commercial properties	2	\$ 469	\$ 1,754	\$ —	\$ —	\$ 25	\$ 170	\$ 2,418
Power generation	9	—	448	—	—	—	349	797
Infrastructure	3	4	—	—	4	—	—	8
Development and other properties	2	563	554	121	97	1	53	1,389
Investments	2	836	47	409	25	60	1	1,378
Corporate subsidiaries	7	—	—	—	127	—	584	711
Co-investor capital								
Properties	6	—	—	—	—	—	762	762
Total	4	\$ 1,872	\$ 2,803	\$ 530	\$ 253	\$ 86	\$ 1,919	\$ 7,463
Percentage total		25%	38%	7%	3%	1%	26%	100%

Capital Securities

YEARS ENDED DECEMBER 31 (MILLIONS)	2008 to 2010	2011 to 2013	2014 to 2016	2017 to 2018	Total
Corporate preferred shares and preferred securities	\$ —	\$ 346	\$ —	\$ 171	\$ 517
Subsidiary preferred shares	199	199	655	—	1,053
Total	\$ 199	\$ 545	\$ 655	\$ 171	\$ 1,570
Percentage of total	12%	35%	42%	11%	100%

PART 7 – ANALYSIS OF CONSOLIDATED FINANCIAL STATEMENTS

The information in this section enables the reader to reconcile this basis of presentation in our consolidated financial statements to that employed elsewhere in our MD&A. We also provide additional information for certain items not covered within that section. The tables presented on pages 72 and 73 provide a detailed reconciliation between our consolidated financial statements and the basis of presentation throughout the balance of this report.

CONSOLIDATED STATEMENTS OF INCOME

The following table summarizes our consolidated statements of net income:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Revenues	\$ 9,343	\$ 6,897
Net operating income	4,509	3,776
Expenses		
Interest	(1,786)	(1,185)
Current income taxes	(68)	(142)
Asset management and other operating costs	(464)	(333)
Non-controlling interests in the foregoing	(636)	(468)
	1,555	1,648
Other items, net of non-controlling interests	(768)	(478)
Net income	\$ 787	\$ 1,170

Revenues

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Commercial properties	\$ 2,331	\$ 1,500
Power generation	960	894
Infrastructure	599	428
Development and other properties	2,169	1,788
Specialty funds	1,246	908
Investment income and other	2,038	1,379
	\$ 9,343	\$ 6,897

Revenues from commercial properties increased due to the expansion of our operations including the acquisition of a major U.S. portfolio in late 2006, which contributed revenues of \$899 million ended December 31, 2007. The increase in power generation revenues reflects higher pricing and increased generating capacity offset by lower water flows. Infrastructure revenues increased due to the acquisition of the Pacific Northwest operations during the second quarter of 2007; and for the first six months of 2007, we consolidated the results of the electricity transmission system in Chile that we acquired in June 2006. Our specialty funds' revenues increased due to the consolidation of revenues from Western Forest Products and Concert Industries and increased yields from loans issued during the year. Similarly, investment income and other includes revenues from operations consolidated during 2007 that were accounted for on the equity method during 2006.

Net Operating Income

Net operating income includes the following items from our consolidated statements of income: fees earned; other operating revenues less direct operating expenses; investment and other income; and realization gains. These items are described for each business unit in the Part 2 – Performance Review beginning on page 12.

The following table reconciles net operating income to the total operating cash flow in the segmented basis of presentation and net operating income:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Platform	2007	2006
Net operating income		\$ 4,509	\$ 3,776
Add: dividends from equity accounted investments	Private Equity	21	66
dividends from Canary Wharf Group	Commercial Properties	—	87
exchangeable debenture gains	Cash and Financial Assets	331	—
Total operating cash flow		\$ 4,861	\$ 3,929

Expenses

The following table reconciles total interest expense to the categories discussed in the Performance Review and Capital Resources and Liquidity sections:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Corporate borrowings	\$ 146	\$ 126
Property-specific mortgages	1,226	751
Subsidiary borrowings	324	212
Capital securities	90	96
	\$ 1,786	\$ 1,185

Corporate interest expense for the year increased due to higher rates as well as increased borrowing levels established to provide for the Multiplex acquisition. Property-specific and subsidiary borrowing expenses aggregated \$1,550 million during the year, compared with \$963 million last year. The increase is due to secured debt on properties acquired in late 2006 and thus far in 2007, the up-financing of our One Liberty Plaza property from \$400 million to \$850 million as well as associated breakage costs. Interest costs also reflect debt associated with the acquisition of the Pacific Northwest timberland operations in April 2007.

The interests of non-controlling parties in net operating income less expenses aggregated \$636 million on a consolidated basis during the year, compared with \$468 million on a similar basis during 2006. The increase was due to a higher level of operating cash flows within existing partially owned operations. The composition of non-controlling interests is detailed in the table on page 62.

Other Items

Other items are summarized in the following table, and include items that are non-cash in nature and not considered by us to form part of our operating cash flow. Accordingly, they are included in the reconciliation between net income and operating cash flow presented on page 30.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Depreciation and amortization	\$ (1,034)	\$ (600)
Equity accounted loss from investments	(72)	(36)
Provisions and other	(112)	57
Future income taxes	(88)	(203)
Non-controlling interests in the foregoing items	538	304
	\$ (768)	\$ (478)

Depreciation and amortization prior to non-controlling interests increased due to the acquisition of additional assets in a number of segments during 2006 and 2007. Depreciation and amortization for each principal operating segment is summarized in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	2005
Commercial properties	\$ 572	\$ 294	\$ 173
Power generation	164	124	104
Infrastructure	138	68	24
Development and other properties	65	36	16
Specialty funds and private equity investments	89	71	51
Other	6	7	6
	\$ 1,034	\$ 600	\$ 374

The increase in depreciation charges during the year includes \$254 million relating to core office properties acquired since late 2006. The infrastructure category includes depreciation and amortization of timberlands and industrial assets acquired upon our purchase of Longview Fibre in the second quarter of 2007, offset by the exclusion of similar charges relating to our Chilean transmission operations as we no longer consolidate these results.

The following table summarizes earnings from our equity accounted investments for the past three years:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	2005
Norbord	\$ (17)	\$ 37	\$ 87
Fraser Papers	(23)	(62)	(13)
Stelco	(32)	(11)	—
Falconbridge	—	—	145
	\$ (72)	\$ (36)	\$ 219

Norbord and Fraser Papers were impacted by low product prices in North America. Fraser Papers also faced higher input costs and incurred additional restructuring charges. We record our share of Stelco's results one quarter in arrears, however because the carrying value to our investment is nominal, we did not record any amount in respect of their second and third quarter results.

Provisions and other, which largely represent revaluation items, contributed a loss of \$112 million in 2007 compared with an income of \$57 million in 2006 and are summarized in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006	2005
Norbord exchangeable debentures	\$ (9)	\$ 59	\$ (10)
Interest rate contracts	(64)	7	(16)
Power contracts	(63)	—	—
Stelco recovery of equity accounted losses	43	—	—
Other	(19)	(9)	(33)
	\$ (112)	\$ 57	\$ (59)

Revaluation items are non-cash accounting adjustments that we are required to record under GAAP to reflect changes in value of contractual arrangements that we do not believe are appropriately included in operating cash flow. Items being revalued include debentures issued by us that are exchangeable into 20 million Norbord common shares, which are revalued based on changes in the Norbord share price during the period. We hold the 20 million shares into which the debentures are exchangeable, but are not permitted to mark the investment to market.

Revaluation items also include the impact of revaluing fixed rate financial contracts that we maintain in order to provide an economic hedge against the impact of possible higher interest rates on the value of our long duration interest sensitive assets. The U.S. 10-year treasury rate moved from 4.70% to 4.02% between December 31, 2006 and December 31, 2007, which led to a \$64 million decline in the value of these contracts, however we believe that this is offset by a corresponding impact on the value of the assets being hedged. Accounting rules require that we revalue these contracts each period even if the corresponding assets are not revalued.

Within our power operations, we enter into long-term contracts to provide generation capacity, and are required to record changes in the value of these contracts through net income whereas we are not permitted to record the corresponding increase in the value of the capacity that we have pre-sold.

We sold our investment in Stelco during the fourth quarter of 2007 for proceeds substantially in excess of our book value and accordingly recovered \$43 million of accumulated equity accounted losses in addition to a disposition gain of \$231 million.

Our future income tax provision was lower than in 2006 on a year-to-date basis, due principally to the inclusion in that year of charges related to a reduction in income tax rates that lowered the value of our tax pools. Future income taxes in the first and third quarters of 2007 included a reversals of an income tax liability associated with our U.S. homebuilding operations totalling \$51 million following the receipt of a final assessment from income tax authorities in respect of a prior tax year.

CONSOLIDATED BALANCE SHEETS

Total assets at book value increased to \$55.6 billion as at December 31, 2007 from \$40.7 billion at the end of 2006.

AS AT DECEMBER 31 (MILLIONS)	Book Value	
	2007	2006
Assets		
Cash and cash equivalents and financial assets	\$ 3,090	\$ 2,869
Investments	1,352	775
Accounts receivable and other	7,327	4,805
Intangible assets	1,773	1,146
Goodwill	1,528	669
Operating assets		
Property, plant and equipment	37,790	28,082
Securities	1,828	1,711
Loans and notes receivable	909	651
	\$ 55,597	\$ 40,708

Investments

Investments represent equity accounted interests in partially owned companies as set forth in the following table, which are discussed further within the relevant business segments in the Description of Operating Platforms.

AS AT DECEMBER 31 (MILLIONS)	Business Segment	% of Investment		Book Value	
		2007	2006	2007	2006
Property lands	Commercial Office	20-25%	—	\$ 382	\$ —
Chile transmission	Transmission	28%	28%	330	—
Brazil transmission	Transmission	7.5-25%	7.5-25%	205	157
Norbord Inc.	Investments	41%	38%	180	178
Real Estate Finance Fund	Specialty Funds	27%	33%	148	139
Fraser Papers Inc.	Investments	56%	49%	—	141
Stelco Inc.	Specialty Funds	—	23%	—	44
Other	Various			107	116
Total				\$ 1,352	\$ 775

We acquired interests in four commercial office funds with our acquisition of Multiplex. We commenced accounting for our 28% interest in the Chilean transmission operations on an equity accounted basis on June 30, 2007 following a change in the ownership structure and consolidated the operations at that time. The Brazil transmission investments consist of interests in transmission concessions ranging from 7.5% to 25% that we account for using the equity method as a result of the significant influence that we exercise. We increased our investment in Norbord to 60.2 million shares through the purchase of 5.8 million shares at a cost of \$42 million. We syndicated a portion of our interest in the Real Estate Finance Fund to an institutional investor during the third quarter. We began accounting for our investment in Fraser Papers on a consolidated basis following the increase in our ownership to 56%. Our investment in Stelco had nominal book value at the end of the third quarter. The purchase of Stelco by U.S. Steel was approved on October 31, 2007. We received \$274 million in proceeds for our investment and recorded a \$231 million pre-tax cash gain.

Accounts Receivable and Other

AS AT DECEMBER 31 (MILLIONS)	Book Value	
	2007	2006
Accounts receivable	\$ 2,892	\$ 1,597
Prepaid expenses and other assets	2,930	1,902
Restricted cash	627	961
Inventory	878	345
	\$ 7,327	\$ 4,805

These balances include amounts receivable by the company in respect of contracted revenues owing but not yet collected, and dividends, interest and fees owing to the company. Prepaid expenses and other assets include amounts accrued to reflect the straight-lining of long-term contracted revenues and capitalized lease values in accordance with accounting guidelines and U.S. intangible assets increased during the year due largely to the acquisition of Multiplex. Restricted cash represents cash balances placed on deposit in connection with financing arrangements and insurance contracts, including the defeasement of long-term property-specific mortgages. The distribution of these assets among our business units is presented in the tables on page 72.

Goodwill

Goodwill represents purchase consideration that is not specifically allocated to the tangible and intangible assets being acquired. The balance as at December 31, 2007 includes \$694 million of goodwill incurred on the acquisition of Multiplex Group during the fourth quarter of 2007 as discussed within the Property Operations segment; and \$593 million of goodwill incurred on the acquisition of Longview Fibre Company during the second quarter of 2007 as discussed within the Infrastructure segment. Goodwill as at December 31, 2006 included an amount of \$483 million that arose from the purchase of a transmission system in Chile during 2006. We commenced equity accounting this investment in June 2007 and accordingly no longer present this amount as goodwill as it is imbedded within the carrying value of the investment.

Property, Plant and Equipment

AS AT DECEMBER 31 (MILLIONS)	Book Value	
	2007	2006
Commercial properties	\$ 20,984	\$ 16,058
Power generation	5,137	4,309
Infrastructure	3,046	2,940
Development and other properties	7,573	4,156
Other plant and equipment	1,050	619
	\$ 37,790	\$ 28,082

The changes in these balances are discussed within each of the relevant business units within the Description of Operating Platforms section. Commercial properties includes, office and retail property assets. Development and other properties include opportunity investments, residential properties, properties under development and properties held for development.

Securities

Securities include \$1.6 billion (2006 – \$1.5 billion) of largely fixed income securities held through our insurance operations, as well as our \$182 million (2006 – \$182 million) common share investment in Canary Wharf Group, which is included in our core office property operations and continues to be carried at historic cost.

Loans and Notes Receivable

Loans and notes receivable consist largely of loans advanced by our bridge lending operations, included in specialty funds.

CONSOLIDATED STATEMENTS OF CASH FLOWS

The following table summarizes the company's cash flows on a consolidated basis:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Operating activities	\$ 3,397	\$ 984
Financing activities	4,392	8,380
Investing activities	(7,432)	(9,111)
Increase in cash and cash equivalents	\$ 357	\$ 253

Operating Activities

Cash flow from operating activities is reconciled to the operating cash flow measure utilized elsewhere in this report as follows:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Operating cash flow	\$ 1,907	\$ 1,801
Adjust for:		
Net change in working capital balances and other	1,254	(418)
Dividends from Canary Wharf Group	—	(87)
Realization gains	(231)	(633)
Undistributed non-controlling interests in cash flow	467	321
Cash flow from operating activities	\$ 3,397	\$ 984

Operating cash flow is discussed in detail elsewhere in this report. Changes in working capital balances reflect the sale of exchangeable debentures for approximately \$750 million and an increase in accounts payable of \$716 million that represents the amount to be paid in 2008 for the purchase of a retail portfolio completed in 2007.

We retained \$467 million (2006 – \$321 million) of operating cash flow within our consolidated subsidiaries in excess of that distributed by way of dividends.

Financing Activities

Financing activities generated \$4.4 billion of cash during 2007, compared with \$8.4 billion in 2006. During the year, we completed a number of property-specific financings within our property, power and infrastructure operations, including a major core office property refinancing which lengthened our maturity profile, and financing for the U.S. Pacific Northwest timberlands acquired during the year. Financing proceeds also includes borrowings at the subsidiary level incurred in connection with the Multiplex acquisition.

During 2007, we increased corporate borrowings by \$476 million to establish funding for our acquisition of Multiplex. We also redeemed higher cost securities during the first and third quarters of the year and repurchased 4.9 million common shares under issuer bids.

We paid shareholder distributions to holders of our common and preferred shares totalling \$316 million (2006 – \$258 million), and repurchased common shares issued by our core office and residential property subsidiaries.

Investing Activities

We invested net capital of \$7.4 billion on a consolidated basis during 2007, compared with a net investment of \$9.1 billion during 2006. We increased our investment in office properties within our core office and opportunity property groups, and invested additional capital through the acquisition and development of power facilities. The most significant acquisitions included that of Multiplex, a major retail property portfolio in Brazil and U.S. timberlands.

RECONCILIATION OF SEGMENTED DISCLOSURE TO CONSOLIDATED FINANCIAL STATEMENTS

Balance Sheet

AS AT DECEMBER 31, 2007

(MILLIONS)	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Cash and Financial Assets	Other Assets	Corporate	Consolidated
Assets										
Operating assets										
Property, plant and equipment										
Commercial properties	\$ 20,984	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 20,984
Power generation	—	5,137	—	—	—	—	—	—	—	5,137
Infrastructure	—	—	3,046	—	—	—	—	—	—	3,046
Development and other properties	—	—	106	7,389	—	78	—	—	—	7,573
Other plant and equipment	18	—	—	—	632	398	2	—	—	1,050
Securities	182	—	—	—	—	1,646	—	—	—	1,828
Loans and notes receivable	—	—	—	—	856	53	—	—	—	909
Cash and cash equivalents	470	77	38	305	74	237	360	—	—	1,561
Financial assets	—	707	—	(41)	180	—	683	—	—	1,529
Investments	382	—	535	30	194	194	17	—	—	1,352
Accounts receivable and other	2,585	848	119	1,398	800	1,208	305	1,837	—	9,100
Goodwill	694	33	591	—	—	37	—	173	—	1,528
Total assets	\$ 25,315	\$ 6,802	\$ 4,435	\$ 9,081	\$ 2,736	\$ 3,851	\$ 1,367	\$ 2,010	\$ —	\$ 55,597
Liabilities and shareholders' equity										
Corporate borrowings	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 2,048	\$ 2,048
Property-specific financing	13,722	3,488	1,796	2,638	—	—	—	—	—	21,644
Other debt of subsidiaries	3,180	797	9	1,364	637	371	394	—	711	7,463
Accounts payable and other liabilities	3,155	879	668	876	434	1,877	65	—	3,148	11,102
Capital securities	—	—	—	—	—	—	—	—	1,570	1,570
Non-controlling interests in net assets	455	213	317	662	528	267	41	—	1,773	4,256
Preferred equity	—	—	—	—	—	—	—	—	870	870
Common equity / net invested capital	4,803	1,425	1,645	3,541	1,137	1,336	867	2,010	(10,120)	6,644
Total liabilities and shareholders' equity	\$ 25,315	\$ 6,802	\$ 4,435	\$ 9,081	\$ 2,736	\$ 3,851	\$ 1,367	\$ 2,010	\$ —	\$ 55,597

AS AT DECEMBER 31, 2006

(MILLIONS)	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Cash and Financial Assets	Other Assets	Corporate	Consolidated
Assets										
Operating assets										
Property, plant and equipment										
Commercial properties	\$16,058	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 16,058
Power generation	—	4,309	—	—	—	—	—	—	—	4,309
Infrastructure	—	—	2,940	—	—	—	—	—	—	2,940
Development and other properties	63	—	111	3,984	—	(2)	—	—	—	4,156
Other plant and equipment	—	—	—	—	453	166	—	—	—	619
Securities	182	—	—	—	29	1,500	—	—	—	1,711
Loans and notes receivable	—	—	—	—	645	6	—	—	—	651
Cash and cash equivalents	11	86	35	407	42	318	305	—	—	1,204
Financial assets	—	532	81	(15)	23	—	1,044	—	—	1,665
Investments	—	—	157	—	160	439	19	—	—	775
Accounts receivable and other	917	436	526	537	445	990	305	1,808	—	5,964
Goodwill	—	27	483	—	—	33	—	113	—	656
Total assets	\$17,231	\$ 5,390	\$ 4,333	\$ 4,913	\$ 1,797	\$ 3,450	\$ 1,673	\$ 1,921	\$ —	\$ 40,708
Liabilities and shareholders' equity										
Corporate borrowings	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 1,507	\$ 1,507
Property-specific financing	11,265	2,704	1,974	1,205	—	—	—	—	—	17,148
Other debt of subsidiaries	908	684	596	981	175	67	74	—	668	4,153
Accounts payable and other liabilities	945	419	317	435	250	1,914	446	—	1,771	6,497
Capital securities	—	—	—	—	—	—	—	—	1,585	1,585
Non-controlling interests in net assets	340	215	582	509	190	65	4	—	1,829	3,734
Preferred equity	—	—	—	—	—	—	—	—	689	689
Common equity / net invested capital	3,773	1,368	864	1,783	1,182	1,404	1,149	1,921	(8,049)	5,395
Total liabilities and shareholders' equity	\$17,231	\$ 5,390	\$ 4,333	\$ 4,913	\$ 1,797	\$ 3,450	\$ 1,673	\$ 1,921	\$ —	\$ 40,708

Results from Operations

FOR THE YEAR ENDED DECEMBER 31, 2007

(MILLIONS)	Asset Management	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Investment Income / Gains	Corporate	Consolidated
Fees earned	\$ 415	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 415
Revenues less direct operating costs										
Commercial properties	—	1,548	—	—	—	—	—	—	—	1,548
Power generation	—	—	611	—	—	—	—	—	—	611
Infrastructure	—	—	—	290	—	—	—	—	—	290
Development and other properties	—	—	—	7	419	—	(9)	1	—	418
Specialty funds	—	—	—	—	—	370	—	—	—	370
Investment and other income	—	18	—	21	(7)	11	213	370	—	626
Realization gains	—	—	—	—	—	—	—	—	231	231
	415	1,566	611	318	412	381	204	371	231	4,509
Expenses										
Interest	—	843	289	174	72	22	50	7	329	1,786
Asset management and other operating costs	—	—	—	—	—	—	7	—	457	464
Current income taxes	—	10	7	4	(18)	4	42	—	19	68
Non-controlling interests	—	84	54	38	57	14	1	—	388	636
Net income before the following	415	629	261	102	301	341	104	364	(962)	1,555
Dividends	—	—	—	—	—	—	21	—	—	21
Xstrata debenture gain	—	—	—	—	—	—	—	331	—	331
Cash flow from operations	415	629	261	102	301	341	125	695	(962)	1,907
Allocation of fees on Brookfield capital	280	(146)	(68)	(26)	(22)	(18)	—	—	—	—
	695	483	193	76	279	323	125	695	(962)	1,907
Less: asset management expenses	(264)	—	—	—	—	—	—	—	264	—
non-controlling interests	(65)	—	—	—	—	—	—	—	65	—
Cash flow from operations	\$ 366	\$ 483	\$ 193	\$ 76	\$ 279	\$ 323	\$ 125	\$ 695	\$ (633)	\$ 1,907

FOR THE YEAR ENDED DECEMBER 31, 2006

(MILLIONS)	Asset Management	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Investment Income / Gains	Corporate	Consolidated
Fees earned	\$ 257	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 257
Revenues less direct operating costs										
Commercial properties	—	936	—	—	—	—	—	—	—	936
Power generation	—	—	620	—	—	—	—	—	—	620
Infrastructure	—	—	—	200	—	—	—	—	—	200
Development and other properties	—	—	—	6	466	—	(2)	—	—	470
Specialty funds	—	—	—	—	—	228	—	—	—	228
Investment and other income	—	—	—	—	—	1	18	413	—	432
Realization gains	—	—	—	—	—	—	—	—	633	633
	257	936	620	206	466	229	16	413	633	3,776
Expenses										
Interest	—	457	235	109	53	13	32	—	286	1,185
Asset management and other operating costs	—	—	—	—	—	—	17	—	316	333
Current income taxes	—	6	2	8	93	3	3	—	27	142
Non-controlling interests	—	5	46	20	74	49	10	17	247	468
Net income before the following	257	468	337	69	246	164	(46)	396	(243)	1,648
Dividends	—	87	—	—	—	—	66	—	—	153
Cash flow from operations	257	555	337	69	246	164	20	396	(243)	1,801
Allocation of fees on Brookfield capital	226	(121)	(62)	(8)	(21)	(14)	—	—	—	—
	483	434	275	61	225	150	20	396	(243)	1,801
Less: asset management expenses	(192)	—	—	—	—	—	—	—	192	—
non-controlling interests	(54)	—	—	—	—	—	—	—	54	—
Cash flow from operations	\$ 237	\$ 434	\$ 275	\$ 61	\$ 225	\$ 150	\$ 20	\$ 396	\$ 3	\$ 1,801

PART 8 – SUPPLEMENTAL INFORMATION

This section contains information required by applicable continuous disclosure guidelines and to facilitate additional analysis.

CONTRACTUAL OBLIGATIONS

The following table presents the contractual obligations of the company by payment periods:

(MILLIONS)	Total	Payments Due by Period			
		Less than One Year	1 - 3 Years	4 - 5 Years	After 5 Years
Long-term debt					
Property-specific mortgages	\$ 21,644	\$ 4,336	\$ 2,911	\$ 5,959	\$ 8,438
Other debt of subsidiaries	7,463	1,872	3,333	339	1,919
Corporate borrowings	2,048	416	233	362	1,037
Capital securities	1,570	—	199	246	1,125
Lease obligations	27	5	10	6	6
Commitments	1,068	1,068	—	—	—
Interest expense ¹					
Long-term debt	10,130	1,916	2,710	1,834	3,670
Capital securities	541	81	162	133	165
Interest rate swaps	213	73	37	32	71

¹ Represents aggregate interest expense expected to be paid over the term of the obligations. Variable interest rate payments have been calculated based on current rates

Contractual obligations include \$1,068 million (2006 – \$1,074 million) of commitments by the company and its subsidiaries provided in the normal course of business, including commitments to provide bridge financing, and letters of credit and guarantees provided in respect of power sales contracts and reinsurance obligations, of which \$95 million is included as liabilities in the consolidated balance sheets and the balance treated as contingent obligations.

OFF BALANCE SHEET ARRANGEMENTS

We conduct our operations primarily through entities that are fully or proportionately consolidated in our financial statements. We do hold non-controlling interests in entities which are accounted for on an equity basis, as are interests in some of our funds, however we do not guarantee any financial obligations of these entities other than our contractual commitments to provide capital to a fund, which are limited to predetermined amounts.

We utilize various financial instruments in our business to manage risk and make better use of our capital. The fair values of these instruments that are reflected on our balance sheets, are disclosed in Note 18 to our Consolidated Financial Statements and under Financial and Liquidity Risks beginning on page 42.

RELATED-PARTY TRANSACTIONS

In the normal course of operations, the company enters into various transactions on market terms with related parties which have been measured at exchange value and are recognized in the consolidated financial statements. There were no such transactions, individually or in aggregate, that were material to our overall operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In particular, critical accounting policies and estimates utilized in the normal course of preparing the company's financial statements require the determination of future cash flows utilized in assessing net recoverable amounts and net realizable values; depreciation and amortization; value of goodwill and intangible assets; ability to utilize tax losses; the determination of the primary beneficiary of variable interest activities; effectiveness of financial hedges for accounting purposes; and fair values for disclosure purposes.

In making estimates, management relies on external information and observable conditions where possible, supplemented by internal analysis as required. These estimates have been applied in a manner consistent with that in the prior year and there are no known trends, commitments, events or uncertainties that we believe will materially affect the methodology or assumptions utilized

in this report. The estimates are impacted by, among other things, movements in interest rates and other factors, some of which are highly uncertain, as described in the analysis of Business Environment and Risks beginning on page 41 and in the section entitled Financial and Liquidity Risk beginning on page 42. The interrelated nature of these factors prevents us from quantifying the overall impact of these movements on the company's financial statements in a meaningful way. For further reference on critical accounting policies, see our significant accounting policies contained in Note 1 and Changes in Accounting Policies as described below.

CHANGES IN ACCOUNTING POLICIES

Financial Instruments

In 2005, the CICA issued five new accounting standards: Handbook Section 1530, *Comprehensive Income* (Section 1530), Handbook Section 3251, *Equity* (Section 3251), Handbook Section 3855, *Financial Instruments – Recognition and Measurement* (Section 3855), Handbook Section 3865, *Hedges* (Section 3865) and Handbook Section 3861, *Financial Instruments – Disclosure and Presentation* (Section 3861), which provides disclosure and presentation requirements related to the aforementioned standards. These new standards became effective for the company on January 1, 2007.

Comprehensive Income

Section 1530 introduces Comprehensive Income which represents changes in Shareholders' Equity during a period arising from transactions and other events with non-owner sources. Other Comprehensive Income ("OCI") includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation amounts, unrealized gains and losses on derivatives designated to hedge self-sustaining foreign operations, and changes in the fair value of the effective portion of cash flow hedging instruments. The Annual Consolidated Financial Statements include a Statement of Comprehensive Income. Accumulated Other Comprehensive Income ("AOCI"), is presented as a new category of Shareholders' Equity in the Consolidated Balance Sheets.

Equity

Section 3251, *Equity* (Section 3251) establishes standards for the presentation of equity and changes in equity during the reporting period. The requirements of this section are in addition to those noted above in Section 1530. This standard requires the disclosure of both the changes in equity during the periods presented and the components of equity as at the end of the periods presented. As a result of adopting this standard, AOCI has been presented as a separate component of common equity.

Financial Instruments – Recognition and Measurement

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It requires that financial assets and financial liabilities including derivatives be recognized on the balance sheet when the company becomes a party to the contractual provisions of the financial instrument or a non-financial derivative contract. All financial instruments should be measured at fair value on initial recognition except for certain related-party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other liabilities. Transaction costs related to held-for-trading financial assets or liabilities are expensed as incurred. For other financial instruments, transaction costs are capitalized on initial recognition and amortized using the effective interest method of amortization.

Financial assets and financial liabilities held-for-trading are measured at fair value with gains and losses recognized in income in the period in which they arise. Available-for-sale financial assets are measured at fair value with unrealized gains and losses, including changes in foreign exchange rates, being recognized in OCI in the period in which they arise. Financial assets classified as held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading will be measured at amortized cost using the effective interest method of amortization. Investments in equity instruments classified as available-for-sale that do not have a quoted market price in an active market will be measured at cost. The company classifies financial instruments using their applicable default categories except when, in the opinion of management, alternative classification results in a more relevant accounting treatment of the specific instrument.

Derivative instruments are recorded on the balance sheet at fair value, including those derivatives that are embedded in financial instruments or other contracts that are not closely related to the host financial instrument or contract. Changes in the fair values of derivative instruments are recognized in Net Income, except for effective derivatives that are designated as cash flow hedges and hedges of foreign currency exposure of a net investment in a self-sustaining foreign operation not classified as held-for-trading, the fair value change for which are recognized in OCI.

Section 3855 permits an entity to designate any financial instrument as held-for-trading on initial recognition or adoption of the standard, even if that instrument would not otherwise satisfy the definition of held-for-trading set out in Section 3855. Instruments that are classified as held-for-trading by way of this “fair value option” must have reliably measurable fair values.

The company accounts for securities transactions using trade date accounting. Other significant accounting implications arising on adoption of Section 3855 include the initial recognition of certain financial guarantees at fair value on the balance sheet and the use of the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

Hedges

Section 3865 specifies the criteria under which hedge accounting can be applied and how hedge accounting should 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 will be adjusted by gains or losses attributable to the hedged risk and recognized in Net Income. The changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, will be offset by changes in the fair value of the hedging 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 OCI. The ineffective portion will be recognized in Net Income. The amounts recognized in AOCI will be reclassified to Net Income in the periods in which 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, the effective portion of foreign exchange gains and losses on the hedging derivative is recognized in OCI and the ineffective portion is recognized in Net Income.

For hedging relationships existing prior to adopting Section 3865 that are continued and qualify for hedge accounting under the new standard, the transition accounting is as follows: (i) Fair value hedges – any gain or loss on the hedging instrument is recognized in the opening balance of retained earnings on transition and the carrying amount of the hedged item is adjusted by the cumulative change in fair value that reflects the designated hedged risk and the adjustment is included in the opening balance of retained earnings on transition; and (ii) Cash flow hedges and hedges of a net investment in a self-sustaining foreign operation – any gain or loss on the hedging instrument that is determined to be the effective portion is recognized in AOCI and the ineffectiveness in the past periods is included in the opening balance of retained earnings on transition.

Deferred gains or losses on the hedging instrument with respect to hedging relationships that were discontinued prior to the transition date but qualify for hedge accounting under the new standards will be recognized in the carrying amount of the hedged item and amortized to Net Income over the remaining term of the hedged item for fair value hedges, and for cash flow hedges it will be recognized in AOCI and reclassified to Net Income in the same period during which the hedged item affects Net Income. However, for discontinued hedging relationships that do not qualify for hedge accounting under the new standards, the deferred gains and losses are recognized in the opening balance of retained earnings on transition.

Impact of Adopting Sections 1530, 3251, 3855, 3861 and 3865

The company recorded a transition adjustment effective January 1, 2007, attributable to the following: (i) an increase of \$292 million, net of taxes, to opening retained earnings for financial instruments classified as held-for-trading, which includes embedded derivatives in financial instruments and contracts that were not previously recorded at fair value; (ii) recognition of \$185 million, net of taxes, in AOCI related to the unrealized gain on available-for-sale financial instruments, effective cash flow hedges and hedges of net investments in self-sustaining foreign operations; and (iii) reclassification of \$42 million of net foreign currency losses to AOCI, previously classified as the cumulative translation adjustment in Shareholders' Equity. The impact during the year is described in the Consolidated Statements of Comprehensive Income. Net income during 2007 was reduced by \$331 million representing the transitional adjustment in respect of securities sold during the year that would have been recognized under the previous accounting policies.

Accounting Changes

Effective January 1, 2007 the company adopted CICA Handbook Section 1506, *Accounting Changes*. The new standard sets out the conditions that must be met for a change in accounting policy to be applied in accordance with GAAP, specifies how such changes should be applied and requires disclosure of the impact of changes in accounting policies. The standard also specifies that changes in accounting estimate be recognized prospectively in net income and requires disclosure of the impact of a change in estimate on the current and future periods. The adoption of this standard did not have a material impact on the consolidated financial statements.

Variability In Variable Interest Entities

On September 15, 2006, the Emerging Issues Committee issued Abstract No. 163, *Determining the Variability to be Considered in Applying AcG-15* (EIC-163). This EIC provides additional clarification on how to analyze arrangements identified as potential variable interests. EIC-163 was effective for the company on April 1, 2007. The implementation of EIC-163 did not have a material impact to the consolidated financial position or results of operations.

Debt Instruments with Embedded Derivatives

On March 5, 2007, the Emerging Issues Committee issued Abstract No. 164, *Convertible and Other Debt Instruments with Embedded Derivatives* (EIC-164). The EIC provides guidance on how the issuer should account for the financial statement presentation of the instrument, embedded derivatives within the hybrid instrument, the future tax aspects of the instrument and how the instrument is to be treated in earnings per share computations. The implementation of EIC-164 did not have a material impact to the consolidated financial position or results of operations.

ASSESSMENT AND CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Management has evaluated the effectiveness of the company's internal control over financial reporting. Refer to Management's Report on Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting during the year ended December 31, 2007 that have materially affected, or are reasonably likely to materially affect the internal control over financial reporting.

DISCLOSURE CONTROLS

Management, including the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in the Canadian Securities Administrators Multilateral Instrument 52-109). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that such disclosure controls and procedures were effective as of December 31, 2007 in providing reasonable assurance that material information relating to the company and the consolidated subsidiaries would be made known to them within those entities.

CORPORATE DIVIDENDS

The distributions paid by Brookfield on outstanding securities during the past three years are as follows:

	Distribution per Security		
	2007	2006	2005
Class A Common Shares ¹	\$ 0.47	\$ 0.40	\$ 0.26
Class A Preferred Shares			
Series 2	0.99	0.88	0.63
Series 3 ²	—	—	2,012.46
Series 4 + Series 7	0.99	0.88	0.63
Series 8	1.10	1.10	0.74
Series 9	1.01	1.25	1.16
Series 10	1.34	1.27	1.19
Series 11	1.28	1.22	1.14
Series 12	1.26	1.19	1.12
Series 13	0.99	0.88	0.63
Series 14	3.57	3.10	2.25
Series 15	1.15	1.00	0.65
Series 17 ³	1.11	0.12	—
Series 18 ⁴	0.71	—	—
Preferred Securities			
Due 2050 ⁵	0.01	1.85	1.73
Due 2051 ⁶	0.95	1.84	1.71

¹ Adjusted to reflect three-for-two stock split

² Redeemed November 8, 2005

³ Issued November 20, 2006

⁴ Issued May 9, 2007

⁵ Redeemed January 2, 2007

⁶ Redeemed July 3, 2007

QUARTERLY RESULTS

Net income and operating cash flows for the eight recently completed quarters are as follows:

(MILLIONS)	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenues	\$ 3,158	\$ 2,219	\$ 2,125	\$ 1,841	\$ 2,904	\$ 1,405	\$ 1,405	\$ 1,183
Fees earned	92	96	95	132	70	64	69	54
Revenues less direct operating costs								
Commercial property	414	350	396	388	322	194	208	212
Power generation	148	105	170	188	142	122	156	200
Infrastructure	33	54	114	89	70	80	30	20
Development and other properties	115	40	117	146	164	107	129	70
Specialty funds	233	16	59	62	131	29	29	39
Investment and other income	133	248	116	129	78	180	84	90
Realization gains	204	—	27	—	528	79	—	26
	1,372	909	1,094	1,134	1,505	855	705	711
Expenses								
Interest	510	454	424	398	420	291	250	224
Asset management and other operating costs	141	108	105	110	108	70	84	71
Current income taxes	28	(6)	26	20	68	23	37	14
Non-controlling interest in net income before the following	124	103	204	205	142	108	118	100
Net income before the following	569	250	335	401	767	363	216	302
Equity accounted income (loss) from investments	(4)	—	(29)	(39)	(10)	(7)	3	(22)
Depreciation and amortization	(294)	(250)	(267)	(223)	(233)	(136)	(127)	(104)
Provisions and other	(95)	(33)	11	5	(37)	4	70	20
Future income taxes	35	11	(69)	(65)	3	(49)	(86)	(71)
Non-controlling interests in the foregoing items	135	115	172	116	121	70	59	54
Net income	\$ 346	\$ 93	\$ 153	\$ 195	\$ 611	\$ 245	\$ 135	\$ 179

For the three months ended December 31, 2007, we reported operating cash flow of \$575 million, compared to \$859 million during the same period in 2006 as shown in the table on the following page and reported net income of \$346 million and \$611 million for the same periods in 2007 and 2006, respectively.

The results for the three months ended December 31, 2006 included \$528 million of realization gains whereas the results for the fourth quarter of 2007 included \$204 million of realization gains. The contribution from specialty funds during the fourth quarter of 2007 included a \$231 million disposition gain within our restructuring operations whereas the 2006 results from the same unit included a \$59 million net contribution from the settlement of an outstanding trade negotiations involving one of our investee companies. Commercial property operations contributed a higher level of operating cash flow due to acquisitions completed in the fourth quarter of both 2006 and during 2007. Cash flow from commercial property operations in 2006 included an \$87 million dividend from Canary Wharf, which represents an important component of our European property operations.

Commercial office property operations tend to produce consistent results throughout the year due to the long-term nature of the contractual lease arrangements. Quarterly seasonality does exist in our residential property and power generation operations. With respect to our residential operations, the fourth quarter tends to be the strongest as this is the period during which most of the construction is completed and homes are delivered. With respect to our power generation operations, seasonality exists in water inflows and pricing. During the fall rainy season and spring thaw, water inflows tend to be the highest leading to higher generation during those periods; however prices tend not to be as strong as the summer and winter seasons due to the more moderate weather conditions during those periods and associated reductions in demand for electricity. We periodically record realization and other gains, special distributions, as well as gains on losses or any unhedged financial positions throughout our operations and, while the timing of these items is difficult to predict, the dynamic nature of our asset base tends to result in these items occurring on a relatively frequent basis.

Cash flow from operations for the last eight quarters are as follows:

(MILLIONS, EXCEPT PER SHARE AMOUNTS)	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net income before the following	\$ 569	\$ 250	\$ 335	\$ 401	\$ 767	\$ 363	\$ 216	\$ 302
Dividends from equity accounted investments	6	5	5	5	5	5	51	5
Dividends from Canary Wharf	—	—	—	—	87	—	—	—
Exchangeable debenture gain	—	66	100	165	—	—	—	—
Cash flow from operations and gains	575	321	440	571	859	368	267	307
Preferred share dividends	12	13	10	9	8	7	10	10
Cash flow to common shareholders	\$ 563	\$ 308	\$ 430	\$ 562	\$ 851	\$ 361	\$ 257	\$ 297
Common equity – book value	\$ 6,644	\$ 6,328	\$ 6,337	\$ 6,061	\$ 5,395	\$ 4,905	\$ 4,721	\$ 4,663
Common shares outstanding ¹	583.6	581.0	583.6	582.2	581.8	581.0	580.2	579.8
Per common share ¹								
Cash flow from operations	\$ 0.94	\$ 0.52	\$ 0.72	\$ 0.93	\$ 1.42	\$ 0.60	\$ 0.43	\$ 0.50
Net income	0.56	0.13	0.24	0.31	1.01	0.40	0.20	0.29
Dividends	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.07
Book value	11.64	11.17	11.07	10.59	9.37	8.60	8.31	8.19
Market trading price (NYSE)	35.67	38.50	39.90	34.84	32.12	29.56	27.08	24.47

¹ Adjusted to reflect three-for-two stock split

ADDITIONAL SHARE DATA

Basic and Diluted Earnings Per Share

The components of basic and diluted earnings per share are summarized in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Net income	\$ 787	\$ 1,170
Preferred share dividends	(44)	(35)
Net income available for common shareholders	\$ 743	\$ 1,135
Weighted average – common shares	582	580
Dilutive effect of the conversion of notes and options using treasury stock method	17	18
Common shares and common share equivalents	599	598

Issued and Outstanding Common Shares

The number of issued and outstanding common shares changed as follows:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Outstanding at beginning of year	581.8	579.6
Issued (repurchased)		
Dividend reinvestment plan	0.1	0.1
Management share option plan	4.9	2.4
Issuer bid purchases	(5.0)	(0.3)
Acquisition	1.8	—
Outstanding at end of year	583.6	581.8
Unexercised options	27.4	29.0
Total diluted common shares at end of year	611.0	610.8

In calculating our book value per common share, the cash value of our unexercised options of \$469 million (2006 – \$328 million) is added to the book value of our common share equity of \$6,644 million (2006 – \$5,395 million) prior to dividing by the total diluted common shares presented above.

ASSETS UNDER MANAGEMENT

The following tables set forth the assets, net invested capital and commitments managed by Brookfield, including the amounts managed on behalf of co-investors:

		Total Assets Under Management			Co-investor Interests		Brookfield's
	Year		Net Invested	Committed	Net Invested	Committed	Ownership
AS AT DECEMBER 31, 2007 (MILLIONS)	Formed	Assets	Capital	Capital ¹	Capital	Capital	Level
Core and Value Add							
U.S. Core Office ²	2006	\$ 7,650	\$ 1,770	\$ 1,950	\$ 980	\$ 1,025	62%
Canadian Core Office ²	2005	1,641	866	866	650	650	25%
Multiplex Funds ³	2007	2,530	924	924	623	623	various
West Coast Timberlands	2005	911	477	477	243	243	50%
East Coast Timber Fund	2006	205	117	117	72	72	45%
Transmission	2006	2,650	1,207	1,207	877	877	28%
Bridge Loan I	2003	1,082	1,082	1,435	661	814	41%
Bridge Loan II	2007	105	105	936	38	696	26%
Real Estate Finance	various	4,637	1,330	1,624	1,053	1,225	4-51%
Brookfield Real Estate Services Fund	2003	125	84	84	59	59	25%
		21,536	7,962	9,620	5,256	6,284	
Opportunity and Private Equity							
Real Estate Opportunity	2006	988	226	249	93	116	52%
Real Estate Opportunity II	2007	583	92	168	—	43	74%
Brazil Retail Property	2006	1,698	328	800	225	600	25%
Residential Properties – U.S. ⁴	2007	1,384	400	400	200	200	29%
Tricap Restructuring I	2002	878	432	432	211	211	48%
Tricap Restructuring II	2006/7	660	380	842	240	542	36%
		6,191	1,858	2,891	969	1,712	
Listed Securities and Fixed Income							
Equity Funds	various	6,027	6,027	6,027	6,027	6,027	3%
Fixed Income Funds	various	20,210	20,210	20,210	20,210	20,210	na
		26,237	26,237	26,237	26,237	26,237	
Total fee bearing assets/capital		53,964	36,057	38,748	\$ 32,462	\$ 34,233	na
Directly Held Non-Fee Bearing Assets							
Core Office – North America ²		10,357	2,149	2,149			
Core Office – Europe		796	257	257			
Core Office – Australia		6,078	987	987			
Residential Properties – Canada ² / Brazil		1,525	200	200			
Power Generation – North America		5,994	901	901			
Power Generation – Brazil		808	524	524			
Timber – U.S.		2,462	674	674			
Timber – Brazil		97	72	72			
Transmission – Canada / Brazil		430	290	290			
Other		11,829	6,695	6,695			
		40,376	12,749	12,749			
		\$ 94,340	\$ 48,806	\$ 51,497			

¹ Includes incremental co-investment capital

² Held by 51%-owned Brookfield Properties

³ Comprised of four funds with ownerships ranging from 20% to 25%

⁴ Held by 58%-owned Brookfield Homes

Internal Control Over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Brookfield Asset Management Inc. ("Brookfield") is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and the Chief Financial Officer and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Management assessed the effectiveness of Brookfield's internal control over financial reporting as of December 31, 2007, based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that, as of December 31, 2007, Brookfield's internal control over financial reporting is effective. Also, management determined that there were no material weaknesses in Brookfield's internal control over financial reporting as of December 31, 2007. Management excluded from its assessment the internal control over financial reporting at Longview Fibre Inc. ("Longview"), Multiplex Group Limited ("Multiplex"), and Malzoni Properties Inc. ("Malzoni"), which were acquired during 2007, whose total assets, net assets, total revenues, and

net income on a combined basis constitute approximately 22%, 39%, 11% and nil% respectively of the consolidated financial statement amounts as of and for the year ended December 31, 2007.

Management's assessment of the effectiveness of Brookfield's internal control over financial reporting as of December 31, 2007, has been audited by Deloitte & Touche, LLP, Independent Registered Chartered Accountants, who also audited Brookfield's Consolidated Financial Statements for the year ended December 31, 2007. As stated in the Report of Independent Registered Chartered Accountants, Deloitte & Touche, LLP expressed an unqualified opinion on Brookfield's internal control over financial reporting as of December 31, 2007.



Toronto, Canada
March 13, 2008

J. Bruce Flatt
Chief Executive Officer



Brian D. Lawson
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Brookfield Asset Management Inc.

We have audited the internal control over financial reporting of Brookfield Asset Management Inc. and subsidiaries (the "Company") as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Longview Fibre Company ("Longview"), Multiplex Group ("Multiplex"), and Malzoni Properties Inc. ("Malzoni"), which were acquired in 2007 and whose financial statements, on a combined basis, constitute approximately 39% and 22% of net and total assets, respectively, 11% of revenues, and nil% of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2007. Accordingly, our audit did not include the internal control over financial reporting at Longview, Multiplex, and Malzoni. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records

that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards, the consolidated financial statements as of and for the year ended December 31, 2007 of the Company and our report dated March 13, 2008 expressed an unqualified opinion on those financial statements.

Deloitte + Touche LLP

Toronto, Canada
March 13, 2008

Deloitte & Touche, LLP
Independent Registered Chartered Accountants
Licensed Public Accountants

Consolidated Financial Statements

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The accompanying consolidated financial statements and other financial information in this Annual Report have been prepared by the company's management which is responsible for their integrity, consistency, objectivity and reliability. To fulfill this responsibility, the company maintains policies, procedures and systems of internal control to ensure that its reporting practices and accounting and administrative procedures are appropriate to provide a high degree of assurance that relevant and reliable financial information is produced and assets are safeguarded. These controls include the careful selection and training of employees, the establishment of well-defined areas of responsibility and accountability for performance and the communication of policies and code of conduct throughout the company. In addition, the company maintains an internal audit group that conducts periodic audits of all aspects of the company's operations. The Chief Internal Auditor has full access to the Audit Committee.

These consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada, and where appropriate, reflect estimates based on management's judgment. The financial information presented throughout this Annual Report is generally consistent with the information contained in the accompanying consolidated financial statements.

Deloitte & Touche, LLP, the independent registered chartered accountants appointed by the shareholders, have examined the consolidated financial statements set out on pages 84 through 115 in accordance with auditing standards generally accepted in Canada to enable them to express to the shareholders their opinion on the consolidated financial statements. Their report is set out below.

The consolidated financial statements have been further reviewed and approved by the Board of Directors acting through its Audit Committee, which is comprised of directors who are not officers or employees of the company. The Audit Committee, which meets with the auditors and management to review the activities of each and reports to the Board of Directors, oversees management's responsibilities for the financial reporting and internal control systems. The auditors have full and direct access to the Audit Committee and meet periodically with the committee both with and without management present to discuss their audit and related findings.



Toronto, Canada
March 13, 2008

J. Bruce Flatt
Chief Executive Officer



Brian D. Lawson
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Brookfield Asset Management Inc.

We have audited the consolidated balance sheets of Brookfield Asset Management Inc. (the "Company") as at December 31, 2007 and 2006, and the consolidated statements of income, retained earnings, comprehensive income, accumulated other comprehensive income (loss) and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 13, 2008, we reported separately to the Board of Directors and Shareholders of Brookfield Asset Management Inc. that we have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), consolidated financial statements for the same periods, prepared in accordance with Canadian generally accepted accounting principles but which included a footnote providing a reconciliation of accounting principles generally accepted in Canada and the United States of America as it related to the Company.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 13, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.



Toronto, Canada
March 13, 2008

Deloitte & Touche, LLP
Independent Registered Chartered Accountants
Licensed Public Accountants

CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31 (MILLIONS)

	Note	2007	2006
Assets			
Cash and cash equivalents		\$ 1,561	\$ 1,204
Financial assets	3	1,529	1,665
Investments	4	1,352	775
Accounts receivable and other	5	7,327	4,805
Intangible assets	6	1,773	1,146
Goodwill	2	1,528	669
Operating assets			
Property, plant and equipment	7	37,790	28,082
Securities	8	1,828	1,711
Loans and notes receivable	9	909	651
		\$ 55,597	\$ 40,708
Liabilities and shareholders' equity			
Corporate borrowings	10	\$ 2,048	\$ 1,507
Non-recourse borrowings			
Property-specific mortgages	11	21,644	17,148
Subsidiary borrowings	11	7,463	4,153
Accounts payable and other liabilities	12	10,055	5,578
Intangible liabilities	13	1,047	919
Capital securities	14	1,570	1,585
Non-controlling interests in net assets	15	4,256	3,734
Shareholders' equity			
Preferred equity	16	870	689
Common equity	17	6,644	5,395
		\$ 55,597	\$ 40,708

On behalf of the Board:



Robert J. Harding, FCA, Director



Marcel R. Coutu, Director

CONSOLIDATED STATEMENTS OF INCOME

YEARS ENDED DECEMBER 31 (MILLIONS, EXCEPT PER SHARE AMOUNTS)

	Note	2007	2006
Total revenues		\$ 9,343	\$ 6,897
Fees earned		415	257
Revenues less direct operating costs	19		
Commercial properties		1,548	936
Power generation		611	620
Infrastructure		290	200
Development and other properties		418	470
Specialty funds		370	228
		3,652	2,711
Investment and other income		626	432
Realization gains		231	633
		4,509	3,776
Expenses			
Interest		1,786	1,185
Current income taxes	21	68	142
Asset management and other operating costs		464	333
Non-controlling interests in net income before the following	20	636	468
		1,555	1,648
Other items			
Equity accounted loss from investments	22	(72)	(36)
Depreciation and amortization		(1,034)	(600)
Provisions and other		(112)	57
Future income taxes	21	(88)	(203)
Non-controlling interests in the foregoing items	20	538	304
Net income		\$ 787	\$ 1,170
Net income per common share ¹	17		
Diluted		\$ 1.24	\$ 1.90
Basic		\$ 1.27	\$ 1.95

¹ Prior year has been restated to reflect three-for-two stock split on June 1, 2007

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Retained earnings, beginning of year	\$ 4,222	\$ 3,321
Change in accounting policy ¹	292	—
Net income	787	1,170
Preferred equity issue costs	(6)	(5)
Shareholder distributions — preferred equity	(44)	(35)
— common equity	(272)	(223)
Amount paid in excess of book value of common shares purchased for cancellation	(112)	(6)
	\$ 4,867	\$ 4,222

¹ Refer to Note 1(m) for impact of new accounting policies related to financial instruments

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME¹

YEARS ENDED DECEMBER 31 (MILLIONS)	Note	2007	2006
Net income		\$ 787	\$ 1,170
Other comprehensive income (loss)	3		
Foreign currency translation		410	(36)
Available-for-sale securities		(79)	—
Derivative instruments designated as cash flow hedges		(73)	—
Future income taxes on above items		44	—
		302	(36)
Comprehensive income		\$ 1,089	\$ 1,134

¹ Refer to Note 1(m) for impact of new accounting policies related to financial instruments

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)¹

YEARS ENDED DECEMBER 31 (MILLIONS)	2007	2006
Transition adjustment — January 1, 2007	\$ 143	\$ —
Other comprehensive income (loss)	302	(36)
Balance, end of year	\$ 445	\$ (36)

¹ Refer to Note 1(m) for impact of new accounting policies related to financial instruments

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31 (MILLIONS)

	Note	2007	2006
Operating activities			
Net income		\$ 787	\$ 1,170
Adjusted for the following non-cash items			
Depreciation and amortization		1,034	600
Future income taxes and other provisions		200	146
Realization gains		(231)	(633)
Non-controlling interest in non-cash items	20	(538)	(304)
Equity accounted loss and dividends received from investments		93	102
		1,345	1,081
Net change in non-cash working capital balances and other		1,472	(418)
Undistributed non-controlling interests in cash flows		467	321
		3,284	984
Financing activities			
Corporate borrowings, net of repayments	25	476	(110)
Property-specific mortgages, net of repayments	25	2,484	5,437
Other debt of subsidiaries, net of repayments	25	1,824	33
Capital provided by non-controlling interests		268	1,950
Capital securities redemption		(225)	—
Corporate preferred equity issuance		181	174
Common shares and equivalents repurchased, net of issuances	25	(121)	10
Common shares of subsidiaries repurchased, net of issuances		(100)	1,144
Shareholder distributions		(316)	(258)
		4,471	8,380
Investing activities			
Investment in or sale of operating assets, net			
Property	25	(5,798)	(6,482)
Power generation		(452)	(801)
Infrastructure		(1,330)	(1,718)
Securities and loans	25	(528)	(720)
Financial assets	25	636	696
Investments		115	(169)
Other property, plant and equipment		(41)	(4)
Dividends from Canary Wharf Group, plc		—	87
		(7,398)	(9,111)
Cash and cash equivalents			
Increase		357	253
Balance, beginning of year		1,204	951
Balance, end of year		\$ 1,561	\$ 1,204

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with generally accepted accounting principles ("GAAP") as prescribed by the Canadian Institute of Chartered Accountants ("CICA").

(a) Basis of Presentation

All currency amounts are in United States dollars ("U.S. dollars") unless otherwise stated. The consolidated financial statements include the accounts of Brookfield Asset Management Inc. and the entities over which it has voting control, as well as Variable Interest Entities ("VIEs") for which the company is considered to be the primary beneficiary.

The company accounts for investments over which it has significant influence using the equity basis. Interests in jointly controlled partnerships and corporate joint ventures are proportionately consolidated. Measurement of investments in which the company does not have a significant influence depends on the financial instrument classification.

Certain prior year amounts have been reclassified to conform to the current year's presentation.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates are required in the determination of cash flows and probabilities in assessing net recoverable amounts and net realizable values, tax and other provisions, hedge effectiveness, and fair values.

(b) Reporting Currency

The U.S. dollar is the functional currency of the company's head office operations and the U.S. dollar is the company's reporting currency.

The accounts of self-sustaining subsidiaries having a functional currency other than the U.S. dollar are translated using the current rate method. Gains or losses on translation are deferred and included in other comprehensive income in the cumulative translation adjustment account. Gains or losses on foreign currency denominated balances and transactions that are designated as hedges of net investments in these subsidiaries are reported in the same manner.

Foreign currency denominated monetary assets and liabilities of the company and subsidiaries where the functional currency is other than the U.S. dollar, are translated at the rate of exchange prevailing at period-end and revenues and expenses at average rates during the period. Gains or losses on translation of these items are included in the consolidated statements of income. Gains or losses on transactions which hedge these items are also included in the consolidated statements of income. Gains or losses on foreign currency denominated available-for-sale financial instruments are included in other comprehensive income.

(c) Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits and all highly liquid short-term investments with original maturities less than 90 days.

(d) Operating Assets

(i) Commercial Properties

Commercial properties held for investment are carried at cost less accumulated depreciation. Depreciation on buildings is provided during the year on a straight-line basis over the useful lives of the properties to a maximum of 60 years. Depreciation is determined with reference to the carried value, remaining estimated useful life and residual value of each rental property. Tenant improvements and re-leasing costs are deferred and amortized over the lives of the leases to which they relate.

CICA Handbook EIC-140, *Accounting for Operating Leases Acquired in either an Asset Acquisition or a Business Combination* and CICA Handbook EIC-137, *Recognition of Customer Relationships Acquired in a Business Combination* require that when a company acquires real estate in either an asset acquisition or business combination, a portion of the purchase price should be allocated to the in-place leases to reflect the intangible amounts of leasing costs, above or below market tenant and land leases, and tenant relationship values, if any. These intangible costs are amortized over their respective lease terms.

(ii) Power Generation

Power generating facilities are recorded at cost, less accumulated depreciation. Depreciation on power generating facilities and equipment is provided at various rates on a straight-line basis over the estimated service lives of the assets, which are up to 60 years for hydroelectric generation assets.

Power generating facilities under development are recorded at cost, including pre-development expenditures, unless impairment is identified requiring a write-down to estimated fair value.

(iii) Infrastructure

(a) Timberlands

Timber assets are carried at cost, less accumulated depletion. Depletion of timber assets is determined based on the number of cubic metres of timber harvested annually at a fixed rate.

(b) Transmission Infrastructure

Transmission assets are carried at cost, less accumulated depreciation. Depreciation on transmission and distribution facilities is provided at various rates on a straight-line basis over the estimated service lives of the assets, which is up to 40 years.

(iv) Development and Other Properties

Development and other properties consist of residential properties, properties for which a major repositioning program is being conducted and properties which are under construction. These properties are recorded at cost, including pre-development expenditures. Homes and other properties held for sale, which include properties subject to sale agreements, are recorded at the lower of cost and estimated fair value. Income received relating to homes and other properties held for sale is applied against the carried value of these properties. Costs are allocated to the saleable acreage of each project or subdivision in proportion to the anticipated revenue.

(v) Financial Assets, Investments and Securities

Financial Assets include securities that are not an active component of the company's asset management operations and are designated as either held-for-trading or available-for-sale. Investments in securities that are actively deployed in the company's operations are classified as securities and are designated as either held-for-trading or available-for-sale. Financial Assets and Securities are recorded at fair value, with changes in fair value accounted for in net income or other comprehensive income as applicable. Equity instruments designated as available-for-sale financial assets and securities that do not have a quoted market price from an active market are carried at cost.

Investments include investments in the securities of affiliates and are accounted for using the equity method of accounting.

Provisions are established in instances where, in the opinion of management, the carrying values of portfolio securities or portfolio investments has been impaired.

(vi) Loans and Notes Receivable

Loans and notes receivable are recorded initially at their fair value and, with the exception of receivables designated as trading, are subsequently measured at amortized cost using the effective interest method, less any applicable provision for impairment. Loans and receivables designated as held-for-trading are recorded at fair value with changes in fair value accounted for in net income in the period in which they arise. A provision for impairment is established when there is objective evidence that the company will not be able to collect all amounts due according to the original terms of the receivables.

(e) Asset Impairment

For assets other than securities and loans and notes receivable, a write-down to estimated fair value is recognized if the estimated undiscounted future cash flows from an asset or group of assets is less than their carried value. The projections of future cash flows take into account the relevant operating plans and management's best estimate of the most probable set of economic conditions anticipated to prevail in the market.

(f) Accounts Receivable and Other

Trade receivables are recognized initially at fair value and subsequently measured at amortized cost using the effective interest method, less any provision for impairment. Included in accounts receivable and other are restricted cash and inventories which are carried at the lower of average cost and net realizable value and materials and supplies which are valued at the lower of average cost and replacement cost.

(g) Intangible Assets and Liabilities

Intangible assets and liabilities with a finite life are amortized on a straight-line basis over their estimated useful lives, generally not exceeding 20 years, and are tested for impairment when conditions exist which may indicate that the estimated future net cash flows from the asset will be insufficient to recover its carrying amount.

(h) Goodwill

Goodwill represents the excess of the price paid for the acquisition of a consolidated entity over the fair value of the net identifiable tangible and intangible assets acquired.

Goodwill is evaluated for impairment annually or more often if events or circumstances indicate there may be an impairment. If the carrying value of a subsidiary, including the allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the subsidiary's allocated goodwill over the implied fair value of the goodwill, based on the fair value of the assets and liabilities of the subsidiary. Any goodwill impairment is charged to income in the period in which the impairment is identified.

(i) Revenue and Expense Recognition

(i) Asset Management Fee Income

Revenues from performance-based incentive fees are recorded on the accrual basis based upon the amount that would be due under the incentive fee formula at the end of the measurement period established by the contract where it is no longer subject to adjustment based on future events. In some cases this will require that the recognition of performance-based incentive fees be deferred to the end, or towards the end of the contract at which point performance can be accurately measured.

(ii) Commercial Property Operations

Revenue from a commercial property is recognized upon the earlier of attaining a break-even point in cash flow after debt servicing, or the expiration of a reasonable period of time following substantial completion, subject to the time limitation determined when the project is approved, but no later than one year following substantial completion. Prior to this, the property is categorized as a property under development, and related revenue is applied to reduce development costs.

The company has retained substantially all of the risks and benefits of ownership of its rental properties and therefore accounts for leases with its tenants as operating leases. The total amount of contractual rent to be received from operating leases is recognized on a straight-line basis over the term of the lease; a straight-line or free rent receivable, as applicable is recorded for the difference between the rental revenue recorded and the contractual amount received. Rental revenue includes percentage participating rents and recoveries of operating expenses, including property, capital and similar taxes. Percentage participating rents are recognized when tenants' specified sales targets have been met. Operating expense recoveries are recognized in the period that recoverable costs are chargeable to tenants.

Revenue from commercial land sales is recognized at the time that the risks and rewards of ownership have been transferred, possession or title passes to the purchaser, all material conditions of the sales contract have been met, and a significant cash down payment or appropriate security is received.

(iii) Power Generation

Revenue from the sale of electricity is recorded at the time power is provided based upon output delivered and capacity provided at rates as specified under contract terms or prevailing market rates.

(iv) Infrastructure

(a) Timberlands

Revenue from timberlands is derived from the sale of logs and related products. The company recognizes sales to external customers when the product is shipped and title passes, and collectibility is reasonably assured.

(b) Transmission Infrastructure

Revenue from transmission infrastructure assets is derived from the transmission and distribution of electricity to industrial and retail customers. Revenue is recognized at regulated rates when the electricity is delivered, and collectibility is reasonably assured.

(v) Development and Other Properties

Revenue from residential land sales is recognized at the time that the risks and rewards of ownership have been transferred, possession or title passes to the purchaser, all material conditions of the sales contract have been met, and a significant cash down payment or appropriate security is received.

Revenue from the sale of homes is recognized when title passes to the purchaser upon closing and at which time all proceeds are received or collectability is assured.

Revenue from the sale of condominium units is recognized using the percentage-of-completion method at the time that construction is beyond a preliminary stage, sufficient units are sold and all proceeds are received or collectability is assured.

Revenue from construction projects is recognized by the percentage-of-completion method at the time that construction is beyond a preliminary stage, there are indications that the work will be completed according to plan and all proceeds are received or collectability is assured.

(vi) Securities and Loans and Notes Receivable

Revenue from notes receivable, loans and securities, less a provision for uncollectible amounts, is recorded on the accrual basis.

(vii) Other

Gains on the exchange of assets which do not result from transactions of commercial substance are deferred until realized by sale.

The net proceeds recorded under reinsurance contracts are accounted for as deposits until a reasonable possibility that the company may realize a significant loss from the insurance risk does not exist.

(j) Derivative Financial Instruments

The company and its subsidiaries selectively utilize derivative financial instruments primarily to manage financial risks, including interest rate, commodity and foreign exchange risks. Hedge accounting is applied when the derivative is designated as a hedge of a specific exposure and there is reasonable assurance that it will continue to be effective as a hedge based on an expectation of offsetting cash flows or fair value. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as a hedge or the hedging relationship is terminated. Once discontinued, the cumulative change in fair value of a derivative that was previously deferred by the application of hedge accounting is recognized in income over the remaining term of the original hedging relationship.

Realized and unrealized gains and losses on foreign exchange forward contracts and currency swap contracts designated as hedges of currency risks are included in other comprehensive income when the currency risk relates to a net investment in a self-sustaining subsidiary and are otherwise included in income in the same period as when the underlying asset, liability or anticipated transaction affects income.

Unrealized gains and losses on interest rate forward and swap contracts designated as hedges of future interest payments are included in other comprehensive income when the interest rate risk relates to an anticipated interest payment. The periodic exchanges of payments on interest rate swap contracts designated as hedges of debt are recorded on an accrual basis as an adjustment to interest expense. The periodic exchanges of payments on interest rate contracts designated as hedges of future interest payments are amortized into income over the term of the corresponding interest payments. Unrealized gains and losses on electricity forward and swap contracts designated as hedges of future power generation revenue are included in other comprehensive income. The periodic exchanges of payments on power generation commodity swap contracts designated as hedges are recorded on a settlement basis as an adjustment to power generation revenue. Premiums paid on options are initially recorded as assets and are amortized into earnings over the term of the option contract.

Derivative financial instruments that are not designated as hedges are carried at estimated fair value, and gains and losses arising from changes in fair value are recognized in the period the changes occur. Unrealized gains and losses on interest rate swaps carried to offset corresponding changes in the values of assets and cash flow streams that are not reflected in the consolidated financial statements at December 31, 2007 and 2006 are recorded in other comprehensive income. Realized and unrealized gains and losses on equity derivatives used to offset the change in share prices in respect of vested Deferred Share Units and Restricted Share Appreciation Units are recorded together with the corresponding compensation expense. Realized and unrealized gains on other derivatives not designated as hedges are recorded in investment and other income. Derivative financial instruments of a financing nature are recorded at fair value determined on a credit adjusted basis.

(k) Income Taxes

The company uses the asset and liability method whereby future income tax assets and liabilities are determined based on differences between the carrying amounts and tax bases of assets and liabilities, and measured using the tax rates and laws that will be in effect when the differences are expected to reverse.

(l) Other Items

(i) Capitalized Costs

Capitalized costs on assets under development and redevelopment include all expenditures incurred in connection with the acquisition, development and construction of the asset until it is available for its intended use. These expenditures consist of costs and interest on debt that is related to these assets. Ancillary income relating specifically to such assets during the development period is treated as a reduction of costs.

(ii) Pension Benefits and Employee Future Benefits

The costs of retirement benefits for defined benefit plans and post-employment benefits are recognized as the benefits are earned by employees. The company uses the accrued benefit method pro-rated using the length of service and management's best estimate assumptions to value its pension and other retirement benefits. Assets are valued at fair value for purposes of calculating the expected return on plan assets. For defined contribution plans, the company expenses amounts as paid.

(iii) Liabilities and Equity

Financial instruments that must or could be settled by a variable number of the company's common shares upon their conversion by the holders as well as the related accrued distributions are classified as liabilities on the Consolidated Balance Sheets under the caption "Capital Securities" and are translated into U.S. dollars at period end rates. Dividends and yield distributions on these instruments are classified as Interest expense in the Consolidated Statements of Income.

(iv) Asset Retirement Obligations

Obligations associated with the retirement of tangible long-lived assets are recorded as liabilities when those obligations are incurred, with the amount of the liabilities initially measured at fair value. These obligations are capitalized to the book value of the related long-lived assets and are depreciated over the useful life of the related asset.

(v) Stock-Based Compensation

The company and most of its consolidated subsidiaries account for stock options using the fair value method. Under the fair value method, compensation expense for stock options is determined based on the fair value at the grant date using an option pricing model and charged to income over the vesting period. The company's publicly traded U.S. and Brazilian homebuilding subsidiaries record the liability and expense of stock options based on their intrinsic value using variable plan accounting, reflecting differences in how these plans operate. Under this method, vested options are revalued each reporting period, and any change in value is included in income.

(m) Changes in Accounting Policies Adopted During 2007

Financial Instruments

The CICA issued five new accounting standards: Handbook Section 1530, *Comprehensive Income* (Section 1530), Handbook Section 3251, *Equity* (Section 3251), Handbook Section 3855, *Financial Instruments – Recognition and Measurement* (Section 3855), Handbook Section 3865, *Hedges* (Section 3865) and Handbook Section 3861, *Financial Instruments – Disclosure and Presentation* (Section 3861), which provides disclosure and presentation requirements related to the aforementioned standards. These new standards became effective for the company on January 1, 2007.

(i) Comprehensive Income

Section 1530 introduces Comprehensive Income which represents changes in Shareholders' Equity during a period arising from transactions and other events with non-owner sources. Other Comprehensive Income ("OCI") includes unrealized gains and losses on financial assets classified as available-for-sale, unrealized foreign currency translation amounts, unrealized gains and losses on derivatives designated to hedge self-sustaining foreign operations, and changes in the fair value of the effective portion of cash flow hedging instruments. The Annual Consolidated Financial Statements include a Statement of Comprehensive Income. Accumulated Other Comprehensive Income ("AOCI"), is presented as a new category of Shareholders' Equity in the Consolidated Balance Sheets.

(ii) *Equity*

Section 3251, Equity (Section 3251) establishes standards for the presentation of equity and changes in equity during the reporting period. The requirements of this section are in addition to those noted above in Section 1530. This standard requires the disclosure of both the changes in equity during the periods presented and the components of equity as at the end of the periods presented. As a result of adopting this standard, AOCI has been presented as a separate component of common equity.

(iii) *Financial Instruments – Recognition and Measurement*

Section 3855 establishes standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. It requires that financial assets and financial liabilities including derivatives be recognized on the balance sheet when the company becomes a party to the contractual provisions of the financial instrument or a non-financial derivative contract. All financial instruments should be measured at fair value on initial recognition except for certain related-party transactions. Measurement in subsequent periods depends on whether the financial instrument has been classified as held-for-trading, available-for-sale, held-to-maturity, loans and receivables, or other liabilities. Transaction costs related to held-for-trading financial assets or liabilities are expensed as incurred. For other financial instruments, transaction costs are capitalized on initial recognition and amortized using the effective interest method of amortization.

Financial assets and financial liabilities held-for-trading are measured at fair value with gains and losses recognized in income in the period in which they arise. Available-for-sale financial assets are measured at fair value with unrealized gains and losses, including changes in foreign exchange rates, being recognized in OCI in the period in which they arise. Financial assets classified as held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading will be measured at amortized cost using the effective interest method of amortization. Investments in equity instruments classified as available-for-sale that do not have a quoted market price in an active market will be measured at cost. The company classifies financial instruments using their applicable default categories except when, in the opinion of management, alternative classification results in a more relevant accounting treatment of the specific instrument.

Derivative instruments are recorded on the balance sheet at fair value, including those derivatives that are embedded in financial instruments or other contracts that are not closely related to the host financial instrument or contract. Changes in the fair values of derivative instruments are recognized in Net Income, except for effective derivatives that are designated as cash flow hedges and hedges of foreign currency exposure of a net investment in a self-sustaining foreign operation not classified as held-for-trading, the fair value change for which are recognized in OCI.

Section 3855 permits an entity to designate any financial instrument as held-for-trading on initial recognition or adoption of the standard, even if that instrument would not otherwise satisfy the definition of held-for-trading set out in Section 3855. Instruments that are classified as held-for-trading by way of this “fair value option” must have reliably measurable fair values.

The company accounts securities transactions using trade date accounting. Other significant accounting implications arising on adoption of Section 3855 include the initial recognition of certain financial guarantees at fair value on the balance sheet and the use of the effective interest method of amortization for any transaction costs or fees, premiums or discounts earned or incurred for financial instruments measured at amortized cost.

(iv) *Hedges*

Section 3865 specifies the criteria under which hedge accounting can be applied and how hedge accounting should 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 will be adjusted by gains or losses attributable to the hedged risk and recognized in Net Income. The changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, will be offset by changes in the fair value of the hedging 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 OCI. The ineffective portion will be recognized in Net Income. The amounts recognized in AOCI will be reclassified to Net Income in the periods in which 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, the effective portion of foreign exchange gains and losses on the hedging derivative is recognized in OCI and the ineffective portion is recognized in Net Income.

For hedging relationships existing prior to adopting Section 3865 that are continued and qualify for hedge accounting under the new standard, the transition accounting is as follows: (i) Fair value hedges – any gain or loss on the hedging instrument is recognized in the opening balance of retained earnings on transition and the carrying amount of the hedged item is adjusted by the cumulative

change in fair value that reflects the designated hedged risk and the adjustment is included in the opening balance of retained earnings on transition; and (ii) Cash flow hedges and hedges of a net investment in a self-sustaining foreign operation – any gain or loss on the hedging instrument that is determined to be the effective portion is recognized in AOCI and the ineffectiveness in the past periods is included in the opening balance of retained earnings on transition.

Deferred gains or losses on the hedging instrument with respect to hedging relationships that were discontinued prior to the transition date but qualify for hedge accounting under the new standards will be recognized in the carrying amount of the hedged item and amortized to Net Income over the remaining term of the hedged item for fair value hedges, and for cash flow hedges it will be recognized in AOCI and reclassified to Net Income in the same period during which the hedged item affects Net Income. However, for discontinued hedging relationships that do not qualify for hedge accounting under the new standards, the deferred gains and losses are recognized in the opening balance of retained earnings on transition.

Impact of Adopting Sections 1530, 3251, 3855, 3861 and 3865

The company recorded a transition adjustment effective January 1, 2007, attributable to the following: (i) an increase of \$292 million, net of taxes, to opening retained earnings for financial instruments classified as held-for-trading, which includes embedded derivatives in financial instruments and contracts that were not previously recorded at fair value; (ii) recognition of \$185 million, net of taxes, in AOCI related to the unrealized gain on available-for-sale financial instruments, effective cash flow hedges and hedges of net investments in self-sustaining foreign operations; and (iii) reclassification of \$42 million of net foreign currency losses to AOCI, previously classified as the cumulative translation adjustment in Shareholders' Equity. The impact during the year is described in the Consolidated Statements of Comprehensive Income. Net income during 2007 was reduced by \$331 million representing the transitional adjustment in respect of securities sold during the year that would have been recognized under the previous accounting policies.

Accounting Changes

Effective January 1, 2007 the company adopted CICA Handbook Section 1506, *Accounting Changes*. The new standard sets out the conditions that must be met for a change in accounting policy to be applied in accordance with GAAP, specifies how such changes should be applied and requires disclosure of the impact of changes in accounting policies. The standard also specifies that changes in accounting estimates be recognized prospectively in net income and requires disclosure of the impact of a change in estimate on the current and future periods. The adoption of this standard did not have a material impact to the consolidated financial statements.

Variability In Variable Interest Entities

On September 15, 2006, the Emerging Issues Committee issued Abstract No. 163, *Determining the Variability to be Considered in Applying AcG-15* (EIC-163). This EIC provides additional clarification on how to analyze and arrangements identified as potential variable interests. EIC-163 was effective for the company on April 1, 2007. The implementation of EIC-163 did not have a material impact on the consolidated financial position or results of operations.

Debt Instruments with Embedded Derivatives

On March 5, 2007, the Emerging Issues Committee issued Abstract No. 164, *Convertible and Other Debt Instruments with Embedded Derivatives* (EIC-164). The EIC provides guidance on how the issuer should account for and the financial statement presentation of the instrument, embedded derivatives within the hybrid instrument, the future tax aspects of the instrument and how the instrument is to be treated in earnings per share computations. The implementation of EIC-164 did not have a material impact on the consolidated financial position or results of operations.

(n) Future Changes in Accounting Policies

Financial Instruments – Disclosures and Presentation

On December 1, 2006, the CICA issued two new accounting standards, Section 3862, *Financial Instruments – Disclosures* and Section 3863, *Financial Instruments – Presentation*. These standards replace Section 3861, *Financial Instruments – Disclosure and Presentation* and enhance the disclosure of the nature and extent of risks arising from financial instruments and how the entity manages those risks. These new standards are effective for fiscal years beginning January 1, 2008.

Capital Disclosures

On December 1, 2006, the CICA issued Section 1535, *Capital Disclosures*. Section 1535 requires the disclosure of: (i) an entity's objectives, policies and process for managing capital; (ii) quantitative data about an entity's managed capital; (iii) whether an entity

has complied with capital requirements; and (iv) if an entity has not complied with such capital requirements, the consequences of such non-compliance. This new standard is effective for fiscal years beginning January 1, 2008.

Goodwill and Intangible Assets

In February 2008, the CICA issued Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Handbook Sections 3062, *Goodwill and Other Intangible Assets* and 3450, *Research and Development Costs*. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to the financial statements relating to fiscal years beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition of intangible assets by profit-oriented enterprises. The company is currently evaluating the impact of Section 3064 on its financial statements.

Inventories

In June 2007, the CICA issued Section 3031, *Inventories*, replacing Section 3030, *Inventories*. This standard provides guidance on the determination of the cost of inventories and the subsequent recognition as an expense, including any write-down to net realizable value. This new standard is effective for fiscal years beginning January 1, 2008. The adoption of Section 3031 is not expected to have a material impact on the consolidated financial statements.

2. ACQUISITIONS

The company accounts for business combinations using the purchase method of accounting which establishes specific criteria for the recognition of intangible assets separately from goodwill. The cost of acquiring a business is allocated to its identifiable tangible and intangible assets and liabilities on the basis of the estimated fair values at the date of purchase with any excess allocated to goodwill.

(a) Completed During 2007

On April 20, 2007, the company completed the acquisition of Longview Fibre Company for approximately \$2.3 billion including assumed debt and recorded \$593 million of goodwill. With this transaction, the company has acquired 588,000 acres of prime, freehold timberlands in Washington and Oregon and an integrated manufacturing operation that produces specialty papers and containers.

The company completed the acquisition of the Multiplex Group's ("Multiplex") stapled securities in the fourth quarter of 2007, comprising the shares of Multiplex Limited and the units of Multiplex Property Trust for, A\$5.05 per stapled security and recorded goodwill of \$694 million. Multiplex is a diversified property business with operations throughout Australia, New Zealand, the United Kingdom and the Middle East. The Multiplex portfolio consists of 24 commercial properties, in addition to construction, development, facilities and funds management divisions.

In December 2007, the company completed the acquisition of a retail mall portfolio consisting of four properties in the São Paulo area and one in Rio de Janeiro from the Malzoni Investment Group. The properties were acquired for approximately \$950 million.

In addition, the company acquired \$972 million of net assets including other commercial properties, hydro generation facilities, and hydro generation developments, together with associated intangibles, working capitals and borrowings. Included in this balance is the acquisition of a real estate equity securities manager which resulted in goodwill of \$55 million in 2007.

The following table summarizes the balance sheet impact of the significant acquisitions in 2007:

(MILLIONS)	<i>Longview</i>	<i>Multiplex</i>	<i>Malzoni</i>	<i>Other</i>	<i>Total</i>
Cash, accounts receivable and other	\$ 487	\$ 1,838	\$ 13	\$ 56	\$ 2,394
Intangible assets	—	513	—	32	545
Goodwill	593	694	13	57	1,357
Property, plant and equipment	1,985	5,188	1,070	1,777	10,020
Non-recourse and corporate borrowings	(1,350)	(4,712)	(95)	(724)	(6,881)
Accounts payable and other liabilities	(160)	(1,441)	(57)	(29)	(1,687)
Intangible liabilities	—	—	—	(107)	(107)
Future income tax asset (liability)	(593)	87	6	(9)	(509)
Non-controlling interests in net assets	—	—	—	(62)	(62)
Preferred equity	—	—	—	(19)	(19)
	\$ 962	\$ 2,167	\$ 950	\$ 972	\$ 5,051

(b) Completed During 2006

The company completed the acquisition of all of the shares of Trizec Properties Inc. and Trizec Canada Inc. (collectively, "Trizec"), for a combined equity value of \$4.8 billion. The Trizec portfolio consists of 58 high quality office properties totalling 29.2 million square feet. The company was joined by a partner in the acquisition and is jointly responsible for managing and operating the portfolio. In addition, the company completed a \$460 million acquisition of 33 commercial properties across the U.S. comprising 5.3 million square feet. The company acquired two buildings in the Washington, D.C. area for \$230 million which are 100% leased to the U.S. Government and are the headquarters of the Transportation Security Administration. The company and a joint venture partner acquired, and subsequently 100% leased to Chevron, a building in Houston for \$120 million, comprising 1.2 million square feet.

The company completed the acquisition of a transmission company, which included over 8,000 kilometers of transmission lines and 51 substations in Chile ("Transelec"), for approximately \$2.5 billion, including assumed liabilities. The acquisition resulted in goodwill of \$483 million. The company holds a 28% interest in Transelec and consolidates it under the VIE rules. The 72% held by institutional investors is reflected in non-controlling interests. As a result of a change in ownership structure in the second quarter of 2007, the company ceased consolidating Transelec and commenced accounting for its interest on an equity accounted basis.

The company completed the acquisition of two hydroelectric generating stations totalling 39 megawatts in Maine for approximately \$146 million including assumed liabilities and the company completed the acquisition of four hydroelectric generating facilities with a total capacity of 50 megawatts located in Ontario for approximately \$197 million, including assumed liabilities.

The following table summarizes the balance sheet impact of the significant acquisitions in 2006:

(MILLIONS)	Trizec	Transelec	Total
Cash, accounts receivable and other	\$ 475	\$ 140	\$ 615
Intangible assets	739	339	1,078
Goodwill	—	483	483
Property, plant and equipment	7,591	1,793	9,384
Non-recourse and corporate borrowings	(5,556)	(1,998)	(7,554)
Accounts payable and other liabilities	(283)	(223)	(506)
Intangible liabilities	(816)	—	(816)
Future income tax liability	(182)	—	(182)
Non-controlling interests in net assets	(1,474)	(215)	(1,689)
Preferred equity	(65)	—	(65)
	\$ 429	\$ 319	\$ 748

3. FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair value of a 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 bid or ask prices, as appropriate, in the most advantageous active market for that instrument to which the company has immediate access. Where bid and ask prices are unavailable, the closing price of the most recent transaction of that instrument is used. In the absence of an active market, fair values are determined based on prevailing market rates (bid and ask prices, as appropriate) for instruments with similar characteristics and risk profiles or internal or external valuation models, such as option pricing models and discounted cash flow analysis, using observable market-based inputs.

Fair values determined using valuation models require the use of assumptions concerning the amount and timing of estimated future cash flows and discount rates. In determining those assumptions, the company looks primarily to external readily observable market inputs including factors such as interest rate yield curves, currency rates, and price and rate volatilities as applicable. In limited circumstances, the company uses input parameters that are not based on observable market data and believes that using possible alternative assumptions will not result in significantly different fair values.

Fair Value of Financial Instruments

As described in Note 1, financial instruments classified or designated as held-for-trading or available-for-sale are typically carried at fair value on the Consolidated Balance Sheet. Equity instruments designated as available-for-sale that do not have a quoted market price from an active market are carried at cost. The carrying amount of available-for-sale financial assets that do not have a quoted market price from an active market was \$182 million at December 31, 2007. Any changes in the fair values of financial instruments classified as held-for-trading or available-for-sale are recognized in Net Income or OCI, respectively. The cumulative changes in the fair values of available-for-sale securities previously recognized in AOCI are reclassified to Net Income when the

underlying security is either sold or there is a decline in value that is considered to be other than temporary. During the year ended December 31, 2007, \$55 million of deferred gains previously recognized in AOCI were reclassified to Net Income due to the sale of available-for-sale securities.

Available-for-sale securities measured at fair value or cost are assessed for impairment at each reporting date. For the year ended December 31, 2007, unrealized gains and unrealized losses in the fair values of available-for-sale financial instruments measured at fair value amounted to \$164 million and \$243 million respectively. Unrealized gains and losses for debt securities are primarily due to changing interest rates and for equity securities, are due to changes in market prices and foreign exchange movements. As at December 31, 2007, the company did not consider any investments to be other than temporarily impaired, as the company has the ability and intent to hold them until the fair value recovers.

Gains or losses arising from changes in the fair value on held-for-trading financial assets are presented in the statements of income, within investment and other income in the period in which they arise. Dividend income on held-for-trading financial assets is recognized in the income statement as part of investment and other income when the company's right to receive payment is established.

Interest on available-for-sale financial assets is calculated using the effective interest method and recognized in the income statement as part of investment and other income. Dividends on available-for-sale equity instruments are recognized in the income statement as part of investment and other income when the company's right to receive payment is established.

Carrying Value and Fair Value of Selected Financial Instruments

As a result of adopting the new financial instruments accounting standards, certain financial instruments are now measured at fair value which were previously reported at cost or amortized cost. This is primarily due to the reclassification of certain securities as held-for-trading securities, which includes securities designated as held-for-trading using the fair value option and available-for-sale securities. The following table provides a comparison of the carrying values and fair values as at December 31, 2007 and December 31, 2006, for selected financial instruments.

December 31, 2007							December 31, 2006	
Financial Instrument Classification	Held-for-Trading	Available-for-Sale		Loans Receivable and Other Liabilities	Total		Total	
Measurement Basis (MILLIONS)	(Fair Value)	(Fair Value)	(Cost)	(Amortized Cost)	(Carrying Value)	(Fair Value)	(Carrying Value)	(Fair Value)
Financial assets								
Cash and cash equivalents	\$ 1,561	\$ —	\$ —	\$ —	\$ 1,561	\$ 1,561	\$ 1,204	\$ 1,204
Financial Assets								
Government bonds	358	62	—	—	420	420	138	138
Corporate bonds	216	155	—	—	371	371	712	1,044
Fixed income securities	—	62	—	—	62	62	42	47
Common shares	118	190	—	—	308	308	548	652
Loans receivable	—	—	—	368	368	368	225	225
	692	469	—	368	1,529	1,529	1,665	2,106
Accounts receivable and other	—	—	—	3,519	3,519	3,519	2,558	2,558
Securities								
Government bonds	—	465	—	—	465	465	375	375
Corporate bonds	—	670	—	—	670	670	693	693
Fixed income securities	—	449	—	—	449	449	392	392
Common shares	—	62	182	—	244	244	251	251
	—	1,646	182	—	1,828	1,828	1,711	1,711
Loans and notes receivable	—	53	—	856	909	909	651	651
	\$ 2,253	\$ 2,168	\$ 182	\$ 4,743	\$ 9,346	\$ 9,346	\$ 7,789	\$ 8,230
Financial liabilities								
Corporate borrowings	\$ —	\$ —	\$ —	\$ 2,048	\$ 2,048	\$ 2,068	\$ 1,507	\$ 1,581
Property-specific mortgages	—	—	—	21,644	21,644	21,644	17,148	17,323
Subsidiary borrowings	—	—	—	7,463	7,463	7,470	4,153	4,162
Accounts payable and other liabilities	161	—	—	8,191	8,352	8,352	5,142	5,142
Capital securities	—	—	—	1,570	1,570	1,561	1,585	1,699
	\$ 161	\$ —	\$ —	\$ 40,916	\$ 41,077	\$ 41,095	\$ 29,535	\$ 29,907

The purpose of the table below is to present the carrying value at December 31, 2006 of those financial instruments that were classified upon adoption as held-for-trading or available-for-sale or designated as held-for-trading using the fair value option, prior to adoption of the new financial instruments accounting standards.

(MILLIONS)	Carrying Value as at December 31, 2006			
	Classified as Held-for-Trading	Designated as Held-for-Trading	Classified as Available-for-Sale	Total
Financial instruments				
Cash and cash equivalents	\$ 1,204	\$ —	\$ —	\$ 1,204
Financial Assets	—	654	786	1,440
Securities	—	—	1,711	1,711
	\$ 1,204	\$ 654	\$ 2,497	\$ 4,355

During the year, the fair value of net financial assets classified as held-for-trading decreased by \$61 million which was recorded in net income. In addition to the above financial instruments, the company designated as a held-for-trading liability, debentures that are exchangeable into 20 million shares of Norbord, see Note 12(c). The fair value of net financial assets designated as held-for-trading increased by \$9 million which was recorded in net income.

Hedging Activities

The company uses derivatives and non-derivative financial instruments to manage exposures to interest, currency, credit and other market risks. When derivatives are used to manage exposures, the company determines for each derivative whether hedge accounting can be applied. Where hedge accounting can be applied, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposure of a net investment in a self-sustaining foreign operation. The derivative must be highly effective in accomplishing the objective of offsetting changes in the fair value or cash flows attributable to the hedged risk both at inception and over the life of the hedge. If it is determined that the derivative is not highly effective as a hedge, hedge accounting is discontinued prospectively.

Cash Flow Hedges

The company uses energy derivative contracts primarily to hedge the sale of power, interest rate swaps to hedge the variability in cash flows related to a variable rate asset or liability, and equity derivatives to hedge the long-term compensation arrangements. All components of each derivative's change in fair value have been included in the assessment of cash flow hedge effectiveness. For the year ended December 31, 2007, pre-tax net unrealized losses of \$73 million were recorded in OCI for the effective portion of the cash flow hedges.

Net Investment Hedges

The company uses foreign exchange contracts and foreign currency denominated debt instruments to manage its foreign currency exposures to net investments in self-sustaining foreign operations having a functional currency other than the U.S. dollar. For the year ended December 31, 2007, unrealized pre-tax net losses of \$208 million were recorded in OCI for the effective portion of hedges of net investments in foreign operations.

4. INVESTMENTS

Equity accounted investments include the following:

(MILLIONS)	Number of Shares		% of Investment		Book Value	
	2007	2006	2007	2006	2007	2006
Property funds	—	—	20 - 25%	—	\$ 382	\$ —
Chile Transmission	—	—	28%	—	330	—
Brazil Transmission	—	—	7.5 - 25%	7.5 - 25%	205	157
Norbord Inc.	60.2	54.4	41%	38%	180	178
Real Estate Finance Fund	—	—	27%	33%	148	139
Fraser Papers Inc.	16.6	14.4	56%	49%	—	141
Stelco Inc.	—	6.2	—	23%	—	44
Other	—	—	—	—	107	116
Total					\$ 1,352	\$ 775

In connection with the acquisition of Multiplex, the company acquired interests in five property funds which are accounted for using the equity method.

The company commenced accounting for its 28% interest in the Chilean transmission operations on an equity accounted basis on June 30, 2007 following a change in the ownership structure. During the third quarter of 2007, the company increased its ownership interest in Fraser Papers and began accounting for its investment on a consolidated basis.

The company completed the disposition of Stelco during the fourth quarter of 2007.

5. ACCOUNTS RECEIVABLE AND OTHER

(MILLIONS)	Note	2007	2006
Accounts receivable	(a)	\$ 2,892	\$ 1,597
Prepaid expenses and other assets	(b)	3,808	2,247
Restricted cash	(c)	627	961
Total		\$ 7,327	\$ 4,805

(a) Accounts Receivable

Included in accounts receivable are loans receivable from employees of the company and consolidated subsidiaries of \$4 million (2006 – \$8 million). None of the company's receivables were impaired at year end.

(b) Prepaid Expenses and Other Assets

Prepaid expenses and other assets includes \$773 million (2006 – \$706 million) of levelized receivables arising from straight-line revenue recognition for property rent and power sales contracts and \$878 million (2006 – \$345 million) of inventory primarily related to completed residential properties and pulp and paper products.

(c) Restricted Cash

Restricted cash relates primarily to commercial property and power generating financing arrangements including defeasement of debt obligations, debt service accounts and deposits held by the company's insurance operations.

6. INTANGIBLE ASSETS

Intangible assets includes \$1,700 million (2006 – \$853 million) related to leases and tenant relationships allocated from the purchase price on the acquisition of commercial properties, net of accumulated amortization.

7. PROPERTY, PLANT AND EQUIPMENT

(MILLIONS)	Note	2007	2006
Commercial properties	(a)	\$ 20,984	\$ 16,058
Power generation	(b)	5,137	4,309
Infrastructure	(c)	3,046	2,940
Development and other properties	(d)	7,573	4,156
Other plant and equipment	(e)	1,050	619
Total		\$ 37,790	\$ 28,082

(a) Commercial Properties

(MILLIONS)	2007	2006
Commercial properties	\$ 22,274	\$ 16,933
Less: accumulated depreciation	1,290	875
Total	\$ 20,984	\$ 16,058

Commercial properties carried at a net book value of approximately \$4,000 million (2006 – \$3,714 million) are situated on land held under leases or other agreements largely expiring after the year 2099. Minimum rental payments on land leases are approximately \$28 million (2006 – \$28 million) annually for the next five years and \$3,256 million (2006 – \$1,230 million) in total on an undiscounted basis.

Construction costs of \$71 million (2006 – \$1 million) were capitalized to the commercial property portfolio for properties undergoing redevelopment in 2007.

During 2007, the company acquired Multiplex and a Brazilian retail mall portfolio which included commercial properties with an ascribed value of \$3,967 million, see Note 2(a).

(b) Power Generation

(MILLIONS)	2007	2006
Hydroelectric power facilities	\$ 5,095	\$ 4,351
Wind energy	393	332
Co-generation and pumped storage	362	260
	5,850	4,943
Less: accumulated depreciation	949	694
	4,901	4,249
Generating facilities under development	236	60
Total	\$ 5,137	\$ 4,309

Generation assets includes the cost of the company's approximately 160 hydroelectric generating stations, wind energy, pumped storage and two gas-fired cogeneration facilities. The company's hydroelectric power facilities operate under various agreements for water rights which extend to or are renewable over terms through the years 2008 to 2046.

(c) Infrastructure

(MILLIONS)	Note	2007	2006
Timberlands	(i)	\$ 2,853	\$ 1,011
Transmission	(ii)	193	1,929
Total		\$ 3,046	\$ 2,940

(i) Timberlands

(MILLIONS)	2007	2006
Timberlands	\$ 3,202	\$ 1,022
Other property, plant and equipment	21	30
	3,223	1,052
Less: accumulated depletion and amortization	370	41
Total	\$ 2,853	\$ 1,011

The carrying value of timberlands includes the cost of the company's 2.5 million acres of timber in eastern and western North America and Brazil. The company acquired \$1,934 million of timberlands through its acquisition of Longview Fibre, see Note 2(a).

(ii) Transmission

(MILLIONS)	2007	2006
Transmission lines and infrastructure	\$ 186	\$ 1,422
Other property, plant and equipment	90	603
	276	2,025
Less: accumulated depreciation	83	96
Total	\$ 193	\$ 1,929

The company's infrastructure assets are comprised of power transmission and distribution networks which are operated under regulated rate base arrangements that are applied to the company's invested capital.

The company discontinued consolidating its Chilean transmission operations during 2007, see Note 4.

(d) Development and Other Properties

Development and other properties include properties relating to the company's opportunity investments, residential properties, properties under development and properties held for development.

(MILLIONS)	Note	2007	2006
Opportunity investments	(i)	\$ 981	\$ 1,039
Residential	(ii)	1,850	1,592
Under development	(iii)	3,584	780
Held for development	(iii)	1,158	745
Total		\$ 7,573	\$ 4,156

(i) Opportunity Investments

(MILLIONS)	2007	2006
Commercial and other properties	\$ 1,017	\$ 1,064
Less: accumulated depreciation	36	25
Total	\$ 981	\$ 1,039

(ii) Residential

(MILLIONS)	2007	2006
Residential properties — owned	\$ 1,747	\$ 1,497
— optioned	103	95
Total	\$ 1,850	\$ 1,592

Residential properties include infrastructure, land (owned and under option), and construction in progress for single-family homes and condominiums. During 2007, the company capitalized \$85 million (2006 – \$72 million) to its residential land operations.

(iii) Development

Properties that are currently under development or held for future development include commercial developments, construction projects, residential land, and rural lands held for future development in agricultural or residential areas. During 2007, the company capitalized construction related costs of \$203 million (2006 – \$54 million) and interest costs of \$58 million (2006 – \$24 million) to its commercial development sites.

(e) Other Plant and Equipment

Other plant and equipment includes capital assets associated primarily with the company's investment in Western Forest Products and Fraser Papers.

8. SECURITIES

(MILLIONS)	2007	2006
Government bonds	\$ 465	\$ 375
Corporate bonds	670	693
Fixed income securities	449	392
Common shares	62	69
Canary Wharf Group common shares	182	182
Total	\$ 1,828	\$ 1,711

Securities represent holdings that are actively deployed in the company's financial operations and include \$1,638 million (2006 – \$1,529 million) owned through the company's insurance operations, as described in Note 18(g).

Securities are measured at fair value except for equity instruments classified as available-for-sale securities that do not have a quoted market price in an active market, which are measured at cost. The fair value of securities at December 31, 2007 was \$2,722 million (2006 – \$2,256 million).

Corporate bonds include fixed rate securities totalling \$634 million (2006 – \$660 million) with an average yield of 5.2% (2006 – 5.3%) and an average maturity of approximately four years. Government bonds and fixed-income securities include predominantly fixed-rate securities.

9. LOANS AND NOTES RECEIVABLE

Loans and notes receivable include corporate loans, bridge loans and other loans, either advanced directly or acquired in the secondary market.

The fair value of the company's loans and notes receivable at December 31, 2007 and 2006 approximated their carrying value based on expected future cash flows, discounted at market rates for assets with similar terms and investment risks.

The loans and notes receivable mature over the next five years (2006 – five years), with an average maturity of approximately two years (2006 – three years) and include fixed rate loans totalling \$5 million (2006 – \$12 million) with an average yield of 10.0% (2006 – 7.0%).

10. CORPORATE BORROWINGS

(MILLIONS)	Market	Maturity	Annual Rate	Currency	2007	2006
Term debt	Private – Canadian	March 27, 2007	11.75%	C\$	\$ —	\$ 1
	Public – Canadian	June 1, 2007	7.25%	C\$	—	107
	Public – U.S.	December 12, 2008	8.13%	US\$	300	300
	Public – U.S.	March 1, 2010	5.75%	US\$	200	200
	Public – U.S.	June 15, 2012	7.13%	US\$	350	350
	Public – U.S.	April 25, 2017	5.80%	US\$	250	—
	Public – Canadian	April 25, 2017	5.29%	C\$	250	—
	Private – Canadian	July 16, 2021	5.50%	C\$	—	43
	Public – U.S.	March 1, 2033	7.38%	US\$	250	250
	Public – Canadian	June 14, 2035	5.95%	C\$	300	256
Commercial paper and bank borrowings			5.61%	N/A	167	—
Deferred financing costs ¹					(19)	—
Total					\$ 2,048	\$ 1,507

¹ Deferred financing costs were reclassified from other assets to corporate borrowings on January 1, 2007 and totalled \$18 million at December 31, 2006, in connection with the adoption of new accounting guidelines (see Note 1(m))

Term debt borrowings have a weighted average interest rate of 6.6% (2006 – 7.2%), and include \$551 million (2006 – \$407 million) repayable in Canadian dollars equivalent to C\$550 million (2006 – C\$476 million).

Commercial paper and bank borrowings is principally commercial paper issued by the company. Commercial paper obligations are backed by the company's credit facilities, which are in the form of a four year revolving term facility.

The fair value of corporate borrowings at December 31, 2007 exceeds the company's carrying values by \$20 million (2006 – \$74 million), determined by way of discounted cash flows using market rates adjusted for the company's credit spreads. Corporate borrowings are recorded initially at their fair value, net of transaction costs incurred, and are subsequently reported at their amortized cost calculated using the effective interest method.

11. NON-RECOURSE BORROWINGS

(a) Property-Specific Mortgages

Principal repayments on property-specific mortgages due over the next five years and thereafter are as follows:

(MILLIONS)	Commercial Properties	Power Generation	Infrastructure	Development and Other Properties	Total Annual Repayments
2008	\$ 2,950	\$ 55	\$ 1,200	\$ 131	\$ 4,336
2009	1,678	138	42	499	2,357
2010	211	161	—	182	554
2011	4,685	88	32	2	4,807
2012	423	667	—	62	1,152
Thereafter	5,479	2,379	522	58	8,438
Total – 2007	\$ 15,426	\$ 3,488	\$ 1,796	\$ 934	\$ 21,644
Total – 2006	\$ 11,650	\$ 2,704	\$ 1,974	\$ 820	\$ 17,148

Property-specific mortgages include \$3,211 million (2006 – \$2,667 million) repayable in Canadian dollars equivalent to C\$3,206 million (2006 – C\$3,120 million); \$164 million (2006 – \$91 million) in Brazilian *real* equivalent to R\$291 million (2006 – R\$195 million); \$561 million (2006 – \$459 million) in British pounds equivalent to £283 million (2006 – £234 million); \$nil (2006 – \$782 million) in Chilean pesos equivalent to CLP\$nil (2006 – CLP\$416 billion); and \$2,751 million (2006 – \$nil) in Australian dollars equivalent to A\$3,144 million (2006 – \$nil). The weighted average interest rate at December 31, 2007 was 6.1% per annum (2006 – 6.8%).

Property-specific mortgages are recorded initially at their fair value, net of transaction costs incurred, and are subsequently reported at their amortized cost calculated using the effective interest method.

The fair value of property-specific mortgages exceeds the company's carrying values by \$nil (2006 – \$175 million), determined by way of discounted cash flows using market rates adjusted for credit spreads applicable to the debt.

(b) Subsidiary Borrowings

Principal repayments on subsidiary borrowings over the next five years and thereafter are as follows:

(MILLIONS)	Commercial Properties	Power Generation	Infrastructure	Development and Other Properties	Other	Total Annual Repayments
2008	\$ 469	\$ —	\$ 4	\$ 563	\$ 836	\$ 1,872
2009	1,754	448	—	554	47	2,803
2010	—	—	—	121	409	530
2011	—	—	4	97	152	253
2012	25	—	—	1	60	86
Thereafter	932	349	—	53	585	1,919
Total – 2007	\$ 3,180	\$ 797	\$ 8	\$ 1,389	\$ 2,089	\$ 7,463
Total – 2006	\$ 908	\$ 684	\$ 596	\$ 1,006	\$ 959	\$ 4,153

The fair value of subsidiary borrowings exceeds the company's carrying values by \$7 million (2006 – \$9 million), determined by way of discounted cash flows using market rates adjusted for credit spreads applicable to the debt.

Subsidiary borrowings include \$1,504 million (2006 – \$1,149 million) repayable in Canadian dollars equivalent to C\$1,502 million (2006 – C\$1,344 million); \$820 million (2006 – \$7 million) in Brazilian *real* equivalent to R\$1,455 million (2006 – R\$15 million); \$9 million (2006 – \$7 million) in British pounds equivalent to £4 million (2005 – £4 million); \$25 million (2006 – \$30 million) in European euros equivalent to €17 million (2006 – €23 million); \$1,960 million (2006 – \$nil) in Australian dollars equivalent to A\$2,240 million (2006 – A\$nil); and \$126 million (2006 – \$nil) in Japanese yen equivalent to ¥14,030 million (2006 – ¥nil). The weighted average interest rate at December 31, 2007 was 9.3% per annum (2006 – 8.4%).

Commercial properties includes \$257 million (2006 – \$257 million) invested by investment partners in the form of debt capital in entities that are required to be consolidated into the company's accounts.

Residential property debt represents amounts drawn under construction financing facilities which are typically established on a project-by-project basis. Amounts drawn are repaid from the proceeds on the sale of building lots, single-family homes and condominiums and redrawn to finance the construction of new homes.

Subsidiary borrowings include obligations pursuant to financial instruments which are recorded as liabilities. These amounts include \$584 million (2006 – \$497 million) of subsidiary obligations relating to the company's international operations subject to credit rating provisions, which are supported by corporate guarantees.

Subsidiary borrowings are recorded initially at their fair value, net of transaction costs incurred, and are subsequently reported at their amortized costs calculated using the effective interest method.

12. ACCOUNTS PAYABLE AND OTHER LIABILITIES

(MILLIONS)	Note	2007	2006
Accounts payable	(a)	\$ 5,212	\$ 3,099
Other liabilities and future tax liabilities	(b)	4,682	2,327
Exchangeable debentures	(c)	161	152
Total		\$ 10,055	\$ 5,578

Acquisitions in 2007 resulted in an increase in accounts payable and other liabilities of \$2,912 million, see Note 2(a).

(a) Accounts Payable

Accounts payable include \$1,560 million (2006 – \$1,473 million) of insurance deposits, claims and other liabilities incurred by the company's insurance subsidiaries.

(b) Other Liabilities and Future Tax Liabilities

Other liabilities include the fair value of the company's obligations to deliver securities it did not own at the time of sale and obligations pursuant to financial instruments recorded as liabilities.

(c) Exchangeable Debentures

A subsidiary of the company issued debentures that are exchangeable for and secured by 20 million common shares of Norbord and mature on September 30, 2029. The debentures are classified as held-for-trading and accordingly the carrying value is adjusted to reflect the market value of the underlying Norbord shares, which at December 31, 2007 was \$161 million, and any change in value is recorded in income. In 2007, a loss of \$9 million was recorded to income as a result of the change in value.

13. INTANGIBLE LIABILITIES

Intangible liabilities represent below-market tenant leases and above-market ground leases assumed on acquisitions, net of accumulated amortization.

14. CAPITAL SECURITIES

The company has the following capital securities outstanding:

(MILLIONS)	Note	2007	2006
Corporate preferred shares and preferred securities	(a)	\$ 517	\$ 663
Subsidiary preferred shares	(b)	1,053	922
Total		\$ 1,570	\$ 1,585

(a) Corporate Preferred Shares and Preferred Securities

(MILLIONS, EXCEPT SHARE INFORMATION)	Shares	Description	Cumulative	Currency	2007	2006
	Outstanding		Distribution			
Class A preferred shares	10,000,000	Series 10	5.75%	C\$	\$ 251	\$ 214
	4,032,401	Series 11	5.50%	C\$	101	86
	7,000,000	Series 12	5.40%	C\$	175	149
Preferred securities	—	Due 2050	8.35%	C\$	—	107
	—	Due 2051	8.30%	C\$	—	107
Deferred financing costs ¹					(10)	—
Total					\$ 517	\$ 663

¹ Deferred financing costs were reclassified from other assets to Capital Securities on January 1, 2007 and totalled \$9 million at December 31, 2006, in connection with the adoption of new accounting guidelines (see Note 1(m))

Subject to approval of the Toronto Stock Exchange, the Series 10, 11 and 12 shares, unless redeemed by the company for cash, are convertible into Class A common shares at a price equal to the greater of 95% of the market price at the time of conversion and C\$2.00, at the option of both the company and the holder, at any time after the following dates:

<i>Class A Preferred Shares</i>	<i>Earliest Permitted Redemption Date</i>	<i>Company's Conversion Option</i>	<i>Holder's Conversion Option</i>
Series 10	September 30, 2008	September 30, 2008	March 31, 2012
Series 11	June 30, 2009	June 30, 2009	December 31, 2013
Series 12	March 31, 2014	March 31, 2014	March 31, 2018

The company redeemed the 8.35% preferred securities on January 2, 2007 and the 8.30% preferred securities on July 3, 2007.

(b) Subsidiary Preferred Shares

<i>(MILLIONS, EXCEPT SHARE INFORMATION)</i>	<i>Shares Outstanding</i>	<i>Description</i>	<i>Cumulative Dividend Rate</i>	<i>Currency</i>	<i>2007</i>	<i>2006</i>
Class AAA preferred shares of	8,000,000	Series F	6.00%	C\$	\$ 200	\$ 171
Brookfield Properties Corporation	4,400,000	Series G	5.25%	US\$	110	110
	8,000,000	Series H	5.75%	C\$	200	171
	8,000,000	Series I	5.20%	C\$	200	171
	8,000,000	Series J	5.00%	C\$	200	171
	6,000,000	Series K	5.20%	C\$	150	128
Deferred financing costs ¹					(7)	—
Total					\$ 1,053	\$ 922

¹ Deferred financing costs were reclassified from other assets to Capital Securities on January 1, 2007 and totalled \$12 million at December 31, 2006, in connection with the adoption of new accounting guidelines (see Note 1(m))

The subsidiary preferred shares are redeemable at the option of both the company and the holder, at any time after the following dates:

<i>Class AAA Preferred Shares</i>	<i>Earliest Permitted Redemption Date</i>	<i>Company's Conversion Option</i>	<i>Holder's Conversion Option</i>
Series F	September 30, 2009	September 30, 2009	March 31, 2013
Series G	June 30, 2011	June 30, 2011	September 30, 2015
Series H	December 31, 2011	December 31, 2011	December 31, 2015
Series I	December 31, 2008	December 31, 2008	December 31, 2010
Series J	June 30, 2010	June 30, 2010	December 31, 2014
Series K	December 31, 2012	December 31, 2012	December 31, 2016

15. NON-CONTROLLING INTERESTS IN NET ASSETS

Non-controlling interests in net assets represent the common and preferred equity in consolidated entities that is owned by other shareholders.

<i>(MILLIONS)</i>	<i>2007</i>	<i>2006</i>
Common equity	\$ 4,105	\$ 3,538
Preferred equity	151	196
Total	\$ 4,256	\$ 3,734

16. PREFERRED EQUITY

Preferred equity represents perpetual preferred shares.

(MILLIONS, EXCEPT SHARE INFORMATION)	Rate	Term	Issued and Outstanding			
			2007	2006	2007	2006
Class A preferred shares						
Series 2	70% P	Perpetual	10,465,100	10,465,100	\$ 169	\$ 169
Series 4	70% P/8.5%	Perpetual	2,800,000	2,800,000	45	45
Series 8	Variable up to P	Perpetual	1,805,948	1,805,948	29	29
Series 9	4.35% ¹	Perpetual	2,194,052	2,194,052	35	35
Series 13	70% P	Perpetual	9,297,700	9,297,700	195	195
Series 15	B.A. + 40 b.p. ²	Perpetual	2,000,000	2,000,000	42	42
Series 17	4.75%	Perpetual	8,000,000	8,000,000	174	174
Series 18	4.75%	Perpetual	8,000,000	—	181	—
Total					\$ 870	\$ 689

¹ Rate was reset from 5.63% per annum in October 2006

² Rate determined in a quarterly auction

P – Prime Rate B.A. – Banker's Acceptance Rate b.p. – Basis Points

The company is authorized to issue an unlimited number of Class A preferred shares and an unlimited number of Class AA preferred shares, issuable in series. No Class AA preferred shares have been issued.

The Class A preferred shares have preference over the Class AA preferred shares, which in turn are entitled to preference over the Class A and Class B common shares on the declaration of dividends and other distributions to shareholders. All series of the outstanding preferred shares have a par value of C\$25 per share.

On May 9, 2007, the company issued 8,000,000 Class A Series 18, 4.75% preferred shares for cash proceeds of C\$200 million, and incurred transaction costs of C\$6 million.

17. COMMON EQUITY

The company is authorized to issue an unlimited number of Class A Limited Voting Shares ("Class A common shares") and 85,120 Class B Limited Voting Shares ("Class B common shares"), together referred to as common shares.

The company's common shareholders' equity is comprised of the following:

(MILLIONS)	2007	2006 ¹
Class A and B common shares	\$ 1,275	\$ 1,215
Contributed surplus	57	—
Retained earnings	4,867	4,222
Accumulated other comprehensive income ²	445	—
Cumulative translation adjustment ²	—	(42)
Common equity	\$ 6,644	\$ 5,395
NUMBER OF SHARES		
Class A common shares	583,527,581	581,730,809
Class B common shares	85,120	85,120
	583,612,701	581,815,929
Unexercised options	27,344,215	28,991,782
Total diluted common shares	610,956,916	610,807,711

¹ Prior year has been restated to reflect three-for-two stock split on June 1, 2007

² Refer to Note 1(m) for impact of new accounting policies related to financial instruments

(a) Class A and Class B Common Shares

The company's Class A common shares and its Class B common shares are each, as a separate class, entitled to elect one-half of the company's Board of Directors. Shareholder approvals for matters other than for the election of directors must be received from the holders of the company's Class A common shares as well as the Class B common shares, each voting as a separate class.

During 2007 and 2006, the number of issued and outstanding common shares changed as follows:

	2007	2006 ¹
Outstanding at beginning of year	581,815,929	579,572,028
Shares issued (repurchased)		
Dividend reinvestment plan	71,251	79,258
Management share option plan	4,920,468	2,421,657
Business acquisitions	1,795,297	—
Repurchases	(4,985,802)	(251,925)
Other	(4,442)	(5,089)
Outstanding at end of year	583,612,701	581,815,929

¹ Prior year has been restated to reflect three-for-two stock split on June 1, 2007

In 2007, the company repurchased 4,985,802 (2006 – 251,925) Class A common shares under normal course issuer bids at a cost of \$163 million (2006 – \$8 million). Proceeds from the issuance of common shares pursuant to the company's dividend reinvestment plan and management share option plan ("MSOP"), totalled \$45 million (2006 – \$18 million).

On November 16, 2007, the company issued 1,795,297 Class A common shares to acquire a real estate securities manager representing consideration of \$66 million.

(b) Earnings Per Share

The components of basic and diluted earnings per share are summarized in the following table:

(MILLIONS)	2007	2006 ¹
Net income	\$ 787	\$ 1,170
Preferred share dividends	(44)	(35)
Net income available for common shareholders	\$ 743	\$ 1,135
Weighted average outstanding common shares	582.4	580.4
Dilutive effect of options using treasury stock method	17.1	17.6
Common shares and common share equivalents	599.5	598.0

¹ Prior year has been restated to reflect three-for-two stock split on June 1, 2007

The holders of Class A common shares and Class B common shares rank on parity with each other with respect to the payment of dividends and the return of capital on the liquidation, dissolution or winding up of the company or any other distribution of the assets of the company among its shareholders for the purpose of winding up its affairs. With respect to the Class A and Class B common shares, there are no dilutive factors, material or otherwise, that would result in different diluted earnings per share. This relationship holds true irrespective of the number of dilutive instruments issued in either one of the respective classes of common stock, as both classes of common shares participate equally, on a pro rata basis in the dividends, earnings and net assets of the company, whether taken before or after dilutive instruments, regardless of which class of common shares is diluted.

(c) Stock-Based Compensation

Options issued under the company's MSOP typically vest proportionately over five years and expire 10 years after the grant date. The exercise price is equal to the market price at the grant date. During 2007, the company granted 3,516,763 (2006 – 3,306,412) options with an average exercise price of C\$38.67 (2006 – C\$27.36) per share. The cost of the options granted was determined using the Black-Scholes model of valuation, assuming a 7.5 year term to exercise (2006 – 7.5 year), 22% volatility (2006 – 17%), a weighted average expected annual dividend yield of 1.2% (2006 – 1.2%) and risk-free rate of 4.0% (2006 – 3.9%). The cost of \$26 million (2006 – \$18 million) is charged to employee compensation expense on an equal basis over the five-year vesting period of the options granted.

The changes in the number of options during 2007 and 2006 were as follows:

	2007		2006 ¹	
	Number of Options (000's)	Weighted Average Exercise Price	Number of Options (000's)	Weighted Average Exercise Price
Outstanding at beginning of year	28,992	C\$ 13.25	28,379	C\$ 11.13
Granted	3,517	38.67	3,306	27.36
Exercised	(4,921)	9.20	(2,421)	7.27
Cancelled	(244)	26.87	(272)	17.69
Outstanding at end of year	27,344	C\$ 17.12	28,992	C\$ 13.25
Exercisable at end of year	15,876		16,921	

¹ Prior year has been restated to reflect three-for-two stock split on June 1, 2007

At December 31, 2007, the following options to purchase Class A common shares were outstanding:

Number Outstanding (000's)	Exercise Price	Weighted Average Remaining Life	Number Exercisable (000's)
1,933	C\$4.90 – C\$5.69	2.1 yrs	1,933
4,039	C\$5.72 – C\$8.56	3.1 yrs	4,039
6,308	C\$8.71 – C\$12.28	3.7 yrs	5,544
3,096	C\$13.37 – C\$16.63	6.1 yrs	1,813
8,463	C\$19.71 – C\$29.47	7.5 yrs	2,537
3,505	C\$29.91 – C\$46.59	9.2 yrs	10
27,344			15,876

A Restricted Share Unit Plan provides for the issuance of Deferred Share Units (“DSUs”), the value of which are equal to the value of a Class A common share, as well as Restricted Share Appreciation Units (“RSAUs”), the value of which are equal to the increase in value of a Class A common share over the value as at the date of issuance. Under this plan, qualifying employees and directors receive varying percentages of their annual incentive bonus or directors’ fees in the form of DSUs. The DSUs and RSAUs vest over periods of up to five years, and DSUs accumulate additional DSUs at the same rate as dividends on common shares based on the market value of the common shares at the time of the dividend. Participants are not allowed to convert DSUs and RSAUs into cash until retirement or cessation of employment. The value of the DSUs, when converted to cash, will be equivalent to the market value of the common shares at the time the conversion takes place. The value of the RSAUs when converted into cash will be equivalent to the difference between the market price of equivalent numbers of common shares at the time the conversion takes place, and the market price on the date the RSAUs are granted. The company uses equity derivative contracts to offset its exposure to the change in share prices in respect of vested DSUs and RSAUs. The value of the vested and unvested DSUs and RSAUs as at December 31, 2007 was \$372 million (2006 – \$335 million).

Employee compensation expense for these plans is charged against income over the vesting period of the DSUs and RSAUs. The amount payable by the company in respect of vested DSUs and RSAUs changes as a result of dividends and share price movements. All of the amounts attributable to changes in the amounts payable by the company are recorded as employee compensation expense in the period of the change, and for the year ended December 31, 2007, including those of operating subsidiaries, totalled \$27 million (2006 – \$44 million), net of the impact of hedging arrangements.

18. RISK MANAGEMENT AND DERIVATIVE FINANCIAL INSTRUMENTS

The company’s activities expose it to a variety of financial risks, including market risk (i.e. currency risk, interest rate risk, and other price risk), credit risk and liquidity risk. The company and its subsidiaries selectively use derivative financial instruments principally to manage risk. Management evaluates and monitors the credit risk of its derivative financial instruments and endeavours to minimize counterparty credit risk through collateral diversification, and other credit risk mitigation techniques. The credit risk of derivative financial instruments is limited to the positive fair value of the instruments. Substantially all of the company’s derivative financial instruments involve counterparties that are banks or other financial institutions in North America, the United Kingdom and Australia with high credit ratings from international credit rating agencies. The company does not expect to incur credit losses in respect of any of these counterparties.

The fair value of interest rate swap contracts which form part of financing arrangements is calculated by way of discounted cash flows using market interest rates. The company endeavours to maintain a matched book of currencies and interest rates. However,

unmatched positions are carried, on occasion, within predetermined exposure limits. These limits are reviewed on a regular basis and the company believes the exposures are manageable and not material in relation to its overall business operations.

The aggregate notional amount of the company's derivative positions at the end of 2007 and 2006 are as follows:

(MILLIONS)	Note	2007	2006
Foreign exchange	(a)	\$ 2,887	\$ 2,908
Interest rates	(b)	8,294	5,126
Credit default swaps	(c)	2,350	2,338
Equity derivatives	(d)	870	424
Commodity instruments (energy)	(e)	193	49
		\$ 14,594	\$ 10,845

(a) Foreign Exchange

At December 31, 2007, the company held foreign exchange contracts with a notional amount of \$1,562 million (2006 – \$1,469 million) at an average exchange rate of \$1.0036 (2006 – \$1.1622) to manage its Canadian dollar exposure. At December 31, 2007, the company held foreign exchange contracts with a notional amount of \$198 million (2006 – \$238 million) at an average exchange rate of \$1.9944 (2006 – \$1.8981) to manage its British pounds exposure. The company held cross currency interest rate swap contracts with a notional amount of \$946 million (2006 – \$574 million), to manage its Canadian dollar and Australian dollar exposure. The remaining foreign exchange contracts relate to the company's Brazilian and European operations.

Included in 2007 income, are net losses on foreign currency balances amounting to \$24 million (2006 – \$14 million) and included in the cumulative translation adjustment account of other comprehensive income are losses in respect of foreign currency contracts entered into for hedging purposes amounting to \$60 million (2006 – \$4 million), which are offset by translation gains on the underlying net assets.

(b) Interest Rates

At December 31, 2007, the company held interest rate swap contracts having an aggregate notional amount of \$800 million (2006 – \$840 million). The company's subsidiaries held interest rate swap contracts having an aggregate notional amount of \$3,191 million (2006 – \$466 million). The company's subsidiaries held interest rate cap contracts with an aggregate notional amount of \$4,303 million (2006 – \$3,820 million).

All interest rate contracts are recorded at an amount equal to fair value and are reflected in the company's consolidated financial statements at year end.

(c) Credit Default Swaps

As at December 31, 2007, the company held credit default swap contracts with an aggregate notional amount of \$2,350 million (2006 – \$2,338 million). Credit default swaps are contracts which are designed to compensate the purchaser for any change in value of an underlying reference asset, based on measurement in credit spreads, upon the occurrence of predetermined credit events. The company is entitled to receive payment in the event of a predetermined credit event for up to \$2,334 million (2006 – \$2,275 million) of the notional amount and could be required to make payment in respect of \$16 million (2006 – \$22 million) of the notional amount.

(d) Equity Derivatives

At December 31, 2007, the company and its subsidiaries held equity derivatives with a notional amount of \$870 million (2006 – \$424 million) recorded at an amount equal to replacement value. A portion of the notional amount represents a hedge of long-term compensation arrangements and the balance represents common equity positions established in connection with the company's investment activities. The fair value of these instruments was reflected in the company's consolidated financial statements at year end.

(e) Commodity Instruments

The company has entered into energy derivative contracts primarily to hedge the sale of generated power. The company endeavours to link forward electricity sale derivatives to specific periods in which it expects to generate electricity for sale. All energy derivative contracts are recorded at an amount equal to replacement value and are reflected in the company's consolidated financial statements at year end.

Other Information Regarding Derivative Financial Instruments

The following table classifies derivatives elected for hedging as fair value hedges, cash flow hedges or net investment hedges, and presents the effective portion of the hedge recorded in either other comprehensive income or in income, depending on the type of hedge and the ineffective portion of the hedge recorded in income during the year.

(MILLIONS)	Notional	Net Gain (Losses)	
		Effective Portion	Ineffective Portion
Fair value hedges	\$ 35	\$ —	\$ —
Cash flow hedges	5,434	(73)	5
Net investment hedges	1,939	(137)	—
	\$ 7,408	\$ (210)	\$ 5

The following table presents the notional amounts underlying the company's derivative instruments by term to maturity, as at December 31, 2007, for both derivatives that are held-for-trading and derivatives that qualify for hedge accounting:

	Residual Term to Contractual Maturity			Total Notional
(MILLIONS)	< 1 year	1 to 5 years	> 5 years	Amount
Held-for-trading				
Foreign exchange derivatives	\$ 869	\$ 1	\$ 6	\$ 876
Interest rate derivatives				
Interest rate swaps	666	1,128	582	2,376
Interest rate caps	272	329	—	601
	938	1,457	582	2,977
Credit default swaps	—	2,303	47	2,350
Equity derivatives	49	523	263	835
Commodity derivatives	19	49	80	148
	\$ 1,875	\$ 4,333	\$ 978	\$ 7,186
Elected for hedge accounting				
Foreign exchange derivatives	\$ 1,390	\$ 182	\$ 439	\$ 2,011
Interest rate derivatives				
Interest rate swaps	62	303	1,250	1,615
Interest rate caps	3,702	—	—	3,702
	3,764	303	1,250	5,317
Equity derivatives	—	35	—	35
Commodity derivatives	27	15	3	45
	\$ 5,181	\$ 535	\$ 1,692	\$ 7,408
	\$ 7,056	\$ 4,868	\$ 2,670	\$ 14,594

The following table presents the change in fair values of the company's derivative positions during the year ended December 31, 2007 and 2006, for both derivatives that are held-for-trading and derivatives that qualify for hedge accounting:

(MILLIONS)	Unrealized Gains During 2007	Unrealized Loss During 2007	Net Change During 2007	2006 Net Change
Foreign exchange derivatives	\$ 23	\$ (107)	\$ (84)	\$ (19)
Interest rate derivatives				
Interest rate swaps	59	(186)	(127)	(2)
Interest rate caps	1	(1)	—	1
	60	(187)	(127)	(1)
Credit default swaps	123	(25)	98	(7)
Equity derivatives	47	(85)	(38)	176
Commodity derivatives	75	(133)	(58)	4
	\$ 328	\$ (537)	\$ (209)	\$ 153

(f) Commitments, Guarantees and Contingencies

The company and its subsidiaries are contingently liable with respect to litigation and claims that arise in the normal course of business.

In the normal course of business, the company and its subsidiaries enter into commitments which primarily support financing arrangements and power purchase agreements. At the end of 2007, the company and its subsidiaries had \$1,068 million (2006 – \$1,074 million) of such commitments outstanding. The company maintains credit facilities and other financial assets to fund these commitments.

The company has acquired \$500 million of insurance for damage and business interruption costs sustained as a result of an act of terrorism. However, a terrorist act could have a material effect on the company's assets to the extent damages exceed the coverage.

The company has reviewed its loan agreements and believes it is in compliance, in all material respects, with the contractual obligations therein.

The company, through its subsidiaries within the residential properties operations, is contingently liable for obligations of its associates in its land development joint ventures. In each case, all of the assets of the joint venture are available first for the purpose of satisfying these obligations, with the balance shared among the participants in accordance with predetermined joint venture arrangements.

In the normal course of operations, the company and its consolidated subsidiaries execute agreements that provide for indemnification and guarantees to third parties in transactions or dealings such as business dispositions, business acquisitions, sales of assets, provision of services, securitization agreements, and underwriting and agency agreements. The company has also agreed to indemnify its directors and certain of its officers and employees. The nature of substantially all of the indemnification undertakings prevents the company from making a reasonable estimate of the maximum potential amount the company could be required to pay third parties, as in most cases the agreements do not 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. Neither the company nor its consolidated subsidiaries have made significant payments in the past nor do they expect at this time to make any significant payments under such indemnification agreements in the future.

(g) Insurance

The company conducts insurance operations as part of its asset management activities. As at December 31, 2007, the company held insurance assets of \$581 million (2006 – \$609 million) in respect of insurance contracts that are accounted for using the deposit method which were offset in each year by an equal amount of reserves and other liabilities. Net underwriting income earned on reinsurance operations was \$67 million (2006 – \$19 million) representing \$544 million (2006 – \$675 million) of premium and other revenues offset by \$477 million (2006 – \$656 million) of reserves and other expenses.

19. REVENUES LESS DIRECT OPERATING COSTS

Direct operating costs include all attributable expenses except interest, depreciation and amortization, taxes, other provisions and non-controlling interest in income. The details are as follows:

(MILLIONS)	2007			2006		
	Revenue	Expenses	Net	Revenue	Expenses	Net
Commercial properties	\$ 2,851	\$ 1,303	\$ 1,548	\$ 1,544	\$ 608	\$ 936
Power generation	959	348	611	893	273	620
Infrastructure	599	309	290	429	229	200
Development and other properties	1,802	1,384	418	1,788	1,318	470
Specialty funds	1,246	876	370	908	680	228
	\$ 7,457	\$ 4,220	\$ 3,237	\$ 5,562	\$ 3,108	\$ 2,454

20. NON-CONTROLLING INTERESTS IN INCOME

Non-controlling interests of others in income is segregated into the non-controlling share of income before certain items and their share of those items, which include depreciation and amortization, taxes and other provisions attributable to the non-controlling interest.

(MILLIONS)	2007	2006
Non-controlling interests' share of income prior to the following	\$ 636	\$ 468
Non-controlling interests' share of depreciation and amortization, and future income taxes and other provisions	(538)	(304)
Non-controlling interests in income	\$ 98	\$ 164
Distributed as recurring dividends		
Preferred	\$ 5	\$ 4
Common	169	143
(Overdistributed) Undistributed	(76)	17
Non-controlling interests in income	\$ 98	\$ 164

21. INCOME TAXES

(MILLIONS)	2007	2006
Current	\$ 68	\$ 142
Future	88	203
Current and future tax expense	\$ 156	\$ 345

(MILLIONS)	2007	2006
Future income tax assets	\$ 932	\$ 890
Future income tax liabilities	(1,925)	(1,326)
Net future income tax liabilities	\$ (993)	\$ (436)

The future income tax assets relate primarily to non-capital losses available to reduce taxable income which may arise in the future. The company and its Canadian subsidiaries have future income tax assets of \$359 million (2006 – \$463 million) that relate to non-capital losses which expire over the next 20 years, and \$105 million (2006 – \$115 million) that relate to capital losses which have no expiry date. The company's U.S. subsidiaries have future income tax assets of \$272 million (2006 – \$189 million) that relate to net operating losses which expire over the next 20 years. The company's international subsidiaries have future income tax assets of \$196 million (2006 – \$123 million) that relate to operating losses which generally have no expiry date. The amount of non-capital and capital losses and deductible temporary differences for which no future income tax assets have been recognized is approximately \$2,825 million (2006 – \$2,426 million). The future income tax liabilities represent the cumulative amount of income tax payable on the differences between the book values and the tax values of the company's assets and liabilities at the rates expected to be effective at the time the differences are anticipated to reverse. The future income tax liabilities relate primarily to differences between book values and tax values of property, plant and equipment due to different depreciation rates for accounting and tax purposes. The future income tax assets and liabilities are recorded in accounts receivable and other and accounts payable and other liabilities on the balance sheet. The following table reflects the company's effective tax rate at December 31, 2007 and 2006:

	2007	2006
Statutory income tax rate	33%	36%
Increase (reduction) in rate resulting from		
Dividends subject to tax prior to receipt by the company	(3)	(3)
Portion of gains not subject to tax	(13)	(12)
Lower income tax rates in other jurisdictions	(8)	(4)
Derecognition of future tax assets/(liabilities)	(7)	3
Foreign exchange gain	9	(1)
Other	3	2
Effective income tax rate	14%	21%

22. EQUITY ACCOUNTED LOSS FROM INVESTMENTS

Equity accounted income (loss) includes the following:

(MILLIONS)	2007	2006
Norbord	\$ (17)	\$ 37
Fraser Papers ¹	(23)	(62)
Stelco Inc. ²	(32)	(11)
Total	\$ (72)	\$ (36)

¹ During 2007, the company increased its ownership in Fraser Papers to 56% and started to account for the investment on a consolidated basis

² During 2007, the company sold its 23% common equity interest in Stelco

23. JOINT VENTURES

The following amounts represent the company's proportionate interest in incorporated and unincorporated joint ventures that are reflected in the company's accounts:

(MILLIONS)	2007	2006
Assets	\$ 4,343	\$ 4,888
Liabilities	2,243	2,769
Operating revenues	715	914
Operating expenses	417	554
Net income	267	223
Cash flows from operating activities	276	251
Cash flows from (used in) investing activities	74	(107)
Cash flows used in financing activities	(187)	(98)

24. POST-EMPLOYMENT BENEFITS

The company offers pension and other post employment benefit plans to its employees. The company's obligations under its defined benefit pension plans are determined periodically through the preparation of actuarial valuations. The benefit plans' income for 2007 was \$2 million (2006 – expense of \$5 million). The discount rate used was 6% (2006 – 5%) with an increase in the rate of compensation of 4% (2006 – 4%) and an investment rate of 8% (2006 – 7%).

(MILLIONS)	2007	2006
Plan assets	\$ 688	\$ 71
Less accrued benefit obligation:		
Defined benefit pension plan	(586)	(81)
Other post-employment benefits	(62)	(16)
Net asset (liability)	40	(26)
Less: Unamortized transitional obligations and net actuarial losses	14	8
Accrued benefit asset (liability)	\$ 54	\$ (18)

In connection with the acquisition of Longview Fibre, the company assumed the pension and other post-employment benefit plans of its employees which represented a net plan asset of \$71 million, of which the company's pro rata interest is \$26 million. This pension plan is held through a 36% owned restructuring fund.

25. SUPPLEMENTAL CASH FLOW INFORMATION

(MILLIONS)	2007	2006
Corporate borrowings		
Issuances	\$ 2,768	\$ 524
Repayments	(2,292)	(634)
Net	\$ 476	\$ (110)
Property-specific mortgages		
Issuances	\$ 4,113	\$ 6,386
Repayments	(1,629)	(949)
Net	\$ 2,484	\$ 5,437
Other debt of subsidiaries		
Issuances	\$ 2,897	\$ 279
Repayments	(1,073)	(246)
Net	\$ 1,824	\$ 33
Common shares		
Issuances	\$ 44	\$ 18
Repayments	(165)	(8)
Net	\$ (121)	\$ 10
Property		
Proceeds of dispositions	\$ 455	\$ 211
Investments	(6,253)	(6,693)
Net	\$ (5,798)	\$ (6,482)
Securities		
Securities sold	\$ 128	\$ 3
Securities purchased	(552)	(327)
Loans collected	707	399
Loans advanced	(811)	(795)
Net	\$ (528)	\$ (720)
Financial assets		
Securities sold	\$ 1,396	\$ 1,446
Securities purchased	(760)	(750)
Net	\$ 636	\$ 696

Cash taxes paid were \$103 million (2006 – \$147 million) and are included in current income taxes. Cash interest paid totalled \$1,686 million (2006 – \$1,101 million). Capital expenditures in the company's power generating operations were \$50 million (2006 – \$40 million), in its property operations were \$45 million (2006 – \$45 million) and in its transmission operations were \$10 million (2006 – \$35 million).

26. SEGMENTED INFORMATION

The company's presentation of reportable segments is based on how management has organized the business in making operating and capital allocation decisions and assessing performance. The company has five reportable segments:

- commercial properties operations, which are principally commercial office properties and retail properties, located primarily in major North American, Brazilian, and Australian cities;
- power generation operations, which are predominantly hydroelectric power generating facilities on river systems in North America and Brazil;
- infrastructure operations, which are predominantly timberlands and electrical transmission and distribution systems. The company's timberland operations are located in North America and Brazil. The electrical transmission and distribution systems are located in Northern Ontario and Chile;
- development and other properties operations, which are principally residential development and homebuilding operations, located primarily in major North American, Brazilian and Australian cities; and
- specialty funds, which include the company's bridge lending, real estate finance and restructuring funds, are managed for the company and for institutional partners.

Non-operating assets and related revenue, cash flow and income are presented as financial assets and other.

Revenue, net income and assets by reportable segments are as follows:

(MILLIONS)	2007			2006		
	Revenue	Net Income	Assets	Revenue	Net Income	Assets
Commercial properties	\$ 2,891	\$ 24	\$ 23,571	\$ 1,499	\$ 19	\$ 17,538
Power generation	971	106	7,106	893	228	5,390
Infrastructure	622	4	4,230	419	56	4,333
Development and other properties	1,751	138	12,115	1,856	377	4,606
Specialty funds	1,368	187	2,676	943	173	1,797
Cash, financial assets and other	1,740	328	5,899	1,287	317	7,044
	\$ 9,343	\$ 787	\$ 55,597	\$ 6,897	\$ 1,170	\$ 40,708

Revenue and assets by geographic segments are as follows:

(MILLIONS)	2007		2006	
	Revenue	Assets	Revenue	Assets
United States	\$ 4,844	\$ 27,156	\$ 2,699	\$ 23,618
Canada	2,604	12,248	3,322	10,111
International	1,895	16,193	876	6,979
	\$ 9,343	\$ 55,597	\$ 6,897	\$ 40,708

27. SUBSEQUENT EVENTS

On January 31, 2008, the company completed the spin-off of a newly created publicly-traded partnership named Brookfield Infrastructure Partners L.P. ("BIP"). The spin-off was implemented by way of a special dividend of a 60% interest in BIP to holders of the company's Class A and Class B Limited Voting shares. Initially, BIP will own interests in five electricity transmission and timber operations in North America, Chile and Brazil.

Five Year Financial Review

AS AT AND FOR THE YEARS ENDED DECEMBER 31

(MILLIONS, EXCEPT PER SHARE AMOUNTS; UNAUDITED)

	2007	2006	2005	2004	2003
Per Common Share (fully diluted)					
Book value	\$ 11.64	\$ 9.37	\$ 7.87	\$ 5.67	\$ 4.99
Cash flow from operations	3.11	2.95	1.46	1.03	0.95
Cash return on book equity	30%	34%	21%	19%	18%
Net income	\$ 1.24	\$ 1.90	\$ 2.72	\$ 0.90	\$ 0.35
Market trading price – NYSE	\$ 35.67	\$ 32.12	\$ 22.37	\$ 16.01	\$ 9.05
Dividends paid	\$ 0.47	\$ 0.39	\$ 0.26	\$ 0.24	\$ 0.22
Common shares outstanding					
Basic	583.6	581.8	579.6	582.1	576.2
Diluted	611.0	610.8	608.0	611.3	610.4
Total (millions)					
Total assets under management	\$ 94,340	\$ 71,121	\$ 49,700	\$ 27,146	\$ 23,108
Consolidated balance sheet assets	55,597	40,708	26,058	20,007	16,309
Corporate borrowings	2,048	1,507	1,620	1,675	1,213
Non-recourse borrowings					
Property-specific mortgages	21,644	17,148	8,756	6,045	4,881
Other debt of subsidiaries	7,463	4,153	2,510	2,373	2,075
Common equity	6,644	5,395	4,514	3,277	2,898
Revenues	9,343	6,897	5,220	3,867	3,370
Operating income	4,509	3,776	2,319	1,793	1,532
Cash flow from operations	1,907	1,801	908	626	590
Net income	787	1,170	1,662	555	232

Corporate Governance

Management and the Board of Directors are committed to working together to achieve strong and effective corporate governance, with the objective of promoting the long-term interests of the company and the enhancement of value for all shareholders. Our Board of Directors is of the view that our corporate governance policies and practices and our disclosure in this regard are appropriate, effective and consistent with the guidelines established by Canadian and U.S. securities regulators. We continue to review our corporate governance policies and practices in relation to evolving legislation, guidelines and best practices.

Our Statement of Corporate Governance Practices is set out in full in the Management Information Circular mailed each year to all our shareholders along with the Notice of our Annual Meeting. This Statement is also available on our web site, **www.brookfield.com**, at “About Brookfield / Corporate Governance.”

You can also access the following documents referred to in the Statement on our web site – the Mandate of our Board of Directors, the Charter of Expectations for Directors, the Charters of the Board’s three Standing Committees (Audit, Governance & Nominating and Management Resources & Compensation), Board Position Descriptions, our Code of Business Conduct and our Corporate Disclosure Policy. We encourage you to review these materials.

Sustainable Development

Management and the Board of Directors are committed to the principle that our business decisions will consider social issues, including the long-term sustainability of our local communities in which we operate, taking into account current and future environmental, safety, health and economic considerations. The review and improvement of our sustainability practices is an ongoing process that we take very seriously throughout our organization.

Environmental initiatives across our operations include energy reduction, water conservation, recycling, air quality standards, wildlife preservation, timber harvesting techniques and erosion control. We believe that these initiatives will benefit the company over the long term from an economic perspective by increasing competitiveness and strengthening the local communities in which we operate. While an appropriate balance is sometimes difficult to achieve, the initiatives we undertake and the investments we make in building our company are guided by our core set of values around sustainable development.

Our renewable energy business is focused on hydroelectricity and wind power generation, while our office properties contain building features, systems and programs that foster environmental responsibility, cost and energy savings for tenants, and the health and safety of all those who work at and visit our properties. We implement comprehensive environmental initiatives in existing properties as well as new development projects to ensure industry standards are achieved and exceeded. For example, our most recent office development, the Bay Adelaide Centre in Toronto, will be built to a Leadership in Energy and Environmental Design (LEED) Gold standard. The LEED® Green Building Rating System is the internationally accepted scorecard for sustainable sites, water efficiency, energy and atmosphere, materials and resources, and indoor environmental quality.

Shareholder Information

Shareholder Enquiries

Shareholder enquiries are welcomed and should be directed to Denis Couture, Senior Vice-President, Investor Relations, Corporate and International Affairs at 416-363-9491 or dcouture@brookfield.com. Alternatively shareholders may contact the company at its administrative head office:

Brookfield Asset Management Inc.

Suite 300, Brookfield Place, Box 762, 181 Bay Street
Toronto, Ontario M5J 2T3
Telephone: 416-363-9491
Facsimile: 416-365-9642
Web Site: www.brookfield.com
E-Mail: inquiries@brookfield.com

Shareholder enquiries relating to dividends, address changes and share certificates should be directed to the company's Transfer Agent:

CIBC Mellon Trust Company

P.O. Box 7010, Adelaide Street Postal Station
Toronto, Ontario M5C 2W9
Telephone: 416-643-5500 or
1-800-387-0825 (Toll free throughout North America)
Facsimile: 416-643-5501
Web Site: www.cibcmellon.com
E-Mail: inquiries@cibcmellon.com

Investor Relations and Communications

We are committed to informing our shareholders of our progress through a comprehensive communications program which includes publication of materials such as our annual report, quarterly interim reports and press releases for material information. We also maintain a web site that provides ready access to these materials, as well as statutory filings, stock and dividend information and other presentations.

Meeting with shareholders is an integral part of our communications program. Directors and management meet with Brookfield's shareholders at our annual meeting and are available to respond to questions at any time. Management is also available to investment analysts, financial advisors and media to ensure that accurate information is available to investors. All materials distributed at any of these meetings are posted on the company's web site.

The text of the company's 2007 Annual Report is available in French on request from the company and is filed with and available through SEDAR at www.sedar.com.

Annual Meeting of Shareholders

The company's 2008 Annual Meeting of Shareholders will be held at 10:30 a.m. on Wednesday, April 30, 2008 at The Design Exchange, 234 Bay Street, Toronto, Ontario and will be webcast through www.brookfield.com.

Stock Exchange Listings

	Symbol	Stock Exchange
Class A Common Shares	BAM	New York
	BAM.A	Toronto
	BAMA	Euronext Amsterdam
Class A Preference Shares		
Series 2	BAM.PR.B	Toronto
Series 4	BAM.PR.C	Toronto
Series 8	BAM.PR.E	Toronto
Series 9	BAM.PR.G	Toronto
Series 10	BAM.PR.H	Toronto
Series 11	BAM.PR.I	Toronto
Series 12	BAM.PR.J	Toronto
Series 13	BAM.PR.K	Toronto
Series 14	BAM.PR.L	Toronto
Series 17	BAM.PR.M	Toronto
Series 18	BAM.PR.N	Toronto

Dividend Reinvestment Plan

Registered holders of Class A Common Shares who are resident in Canada may elect to receive their dividends in the form of newly issued Class A Common Shares at a price equal to the weighted average price at which the shares traded on the Toronto Stock Exchange during the five trading days immediately preceding the payment date of such dividends.

The Dividend Reinvestment Plan allows current shareholders to acquire additional shares in the company without payment of commissions. Further details on the Plan and a Participation Form can be obtained from our administrative head office, our transfer agent or from our web site.

Dividend Record and Payment Dates

	Record Date	Payment Date
Class A Common Shares ¹	First day of February, May, August and November	Last day of February, May, August and November
Class A Preference Shares ¹		
Series 2, 4, 10, 11, 12, 13, 17 and 18	15th day of March, June, September and December	Last day of March, June, September and December
Series 8 and 14	Last day of each month	12th day of following month
Series 9	15th day of January, April, July and October	First day of February, May, August and November

¹ All dividend payments are subject to declaration by the Board of Directors

Board of Directors and Officers

BOARD OF DIRECTORS

Robert J. Harding, F.C.A.

Chairman

Brookfield Asset Management Inc.

Jack L. Cockwell

Group Chairman

Brookfield Asset Management Inc.

Marcel R. Coutu

President and Chief Executive Officer

Canadian Oil Sands Limited

The Hon. J. Trevor Eyton, O.C.

Member of the Senate of Canada

J. Bruce Flatt

Managing Partner and CEO

Brookfield Asset Management Inc.

James K. Gray, O.C.

Founder and former CEO

Canadian Hunter Exploration Ltd.

Maureen Kempston Darkes, O.C., O.ONT.*

Group Vice President and President

Latin America, Africa and Middle East

General Motors Corporation

David W. Kerr

Corporate Director

Lance Liebman

Director

American Law Institute

Philip B. Lind, C.M.

Vice-Chairman

Rogers Communications Inc.

G. Wallace F. McCain, O.C., O.N.B.

Chairman

Maple Leaf Foods Inc.

The Hon. Frank J. McKenna, P.C., O.N.B.

Deputy Chair

TD Bank Financial Group

Dr. Jack M. Mintz

Palmer Chair in Public Policy

University of Calgary

Patricia M. Newson, C.A.*

President and CEO

AltaGas Utility Group Inc.

James A. Pattison, O.C., O.B.C.

Chief Executive Officer

The Jim Pattison Group

George S. Taylor

Corporate Director

* Director-elect

Details on Brookfield's Directors are provided in the Management Information Circular and on Brookfield's web site

CHAIRMEN

Jack L. Cockwell

Group Chairman

Ian G. Cockwell

Residential

Timothy R. Price

Funds Management

Gordon E. Arnell

Commercial Property

Edward C. Kress

Power Generation

John E. Zuccotti

United States

MANAGEMENT COMMITTEE

Barry S. Blattman

Jeffrey M. Blidner

Richard B. Clark

Bryan K. Davis

Luiz Ildefonso Lopes

Steven J. Douglas

J. Bruce Flatt

Harry A. Goldgut

Joseph S. Freedman

Brian W. Kingston

Clifford E. Lai

Brian D. Lawson

Richard J. Legault

Cyrus Madon

Ross A. McDiven

George E. Myhal

Derek G. Pannell

Samuel J.B. Pollock

Aaron W. Regent

Bruce K. Robertson

CORPORATE OFFICERS

J. Bruce Flatt

Chief Executive Officer

Brian D. Lawson

Chief Financial Officer

Alan V. Dean

Corporate Secretary



Mixed Sources
Product group from well-managed
forests, controlled sources and
recycled wood or fiber
www.fsc.org Cert no. SW-COC-1383
© 1996 Forest Stewardship Council

Brookfield incorporates sustainable development practices within our corporation. This document was printed in Canada using vegetable based inks on FSC certified stock.

Savings

Trees: 6 trees preserved for the future
Waste: 1,577 lbs of solid waste was recycled instead of landfilled
Water: 2,464 gallons of wastewater flow saved
Energy: 4,000,000 BTUs of energy was not consumed

CORPORATE OFFICES

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Brookfield Asset Management

2008 Annual Report



Investment Principles

BUSINESS PHILOSOPHY

- Build the business and all relationships based on integrity
- Attract and retain high calibre individuals who will grow with us over the long-term
- Ensure our people think and act like owners in all their decisions
- Treat our clients' money like it is our own

INVESTMENT GUIDELINES

- Invest where we possess competitive advantages
- Acquire assets on a value basis with a goal of maximizing return on capital
- Build sustainable cash flows to provide certainty, reduce risk and lower the cost of capital
- Recognize that superior returns often require contrarian thinking

MEASUREMENT OF OUR CORPORATE SUCCESS

- Measure success based on total return on capital over the long-term
 - Encourage calculated risks, but compare returns with risk
 - Sacrifice short-term profit, if necessary, to achieve long-term capital appreciation
 - Seek profitability rather than growth, because size does not necessarily add value
-

Financial Highlights

AS AT AND FOR THE YEARS ENDED DECEMBER 31

(MILLIONS, EXCEPT PER SHARE AMOUNTS)

	2008	2007	2006	2005	2004
Per fully diluted common share					
Cash flow from operations	\$ 2.33	\$ 3.11	\$ 2.95	\$ 1.46	\$ 1.03
Cash return on equity	23%	30%	34%	21%	19%
Market trading price – NYSE	\$ 15.27	\$ 35.67	\$ 32.12	\$ 22.37	\$ 16.01
Net income	1.02	1.24	1.90	2.72	0.90
Dividends paid	1.45 ¹	0.47	0.39	0.26	0.24
Total					
Assets under management	\$ 78,697	\$ 94,340	\$ 71,121	\$ 49,700	\$ 27,146
Consolidated balance sheet assets	53,611	55,597	40,708	26,058	20,007
Revenues	12,868	9,343	6,897	5,220	3,867
Operating income	4,809	4,509	3,776	2,319	1,793
Cash flow from operations	1,423	1,907	1,801	908	626
Net income	649	787	1,170	1,662	555
Diluted number of common shares outstanding	600	611	611	608	611

¹ Includes Brookfield Infrastructure special dividend of \$0.94

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A Global Asset Manager

We are a long-term, value-oriented investor with approximately \$80 billion of assets under management.

Our primary objective is to generate attractive long-term returns through the ownership of assets producing sustainable cash flows in our areas of expertise – property, power, infrastructure and specialty funds.

We have over 100 years of experience investing and operating and managing these high quality assets globally, and are uniquely positioned to offer specialty investment products to our clients.

NORTH AMERICA – CANADA

\$13.3 billion of assets under management
3,500 employees

Properties

- 29 commercial properties
- 20.3 million sq. ft. of leasable space
- 8,054 acres of residential land held for development, and 3,140 residential lots under development (Alberta and Ontario)
- 5.7 million sq. ft. of commercial developments

Renewable Power

- 32 renewable power plants
- 1,314 megawatts of installed capacity
- 1 wind farm with 189 megawatts of installed capacity

Timberlands

- 1.7 million acres

Electricity Transmission

- 550 kilometres

Specialty Funds

- \$2.0 billion under management

SOUTH AMERICA - BRAZIL AND CHILE

\$7.9 billion of assets under management
5,000 employees

Properties

- 15 retail properties and 2 office properties
- 4 million sq. ft. retail and 78 thousand sq. ft. office properties
- 61 million sq. ft. of residential developments

Renewable Power

- 31 renewable power plants
- 512 megawatts of installed capacity
- 3 new plants under construction with 85 megawatts of capacity
- Approximately 900 megawatts in greenfield projects in the pipeline

Timberlands & Agrilands

- 160,000 acres of timberlands
- 372,000 acres of agrilands

Electricity Transmission

- 10,400 kilometres

NORTH AMERICA – UNITED STATES

\$48.9 billion of assets under management
2,000 employees

Properties

- 60 commercial properties
- 47.0 million sq. ft. of leasable space
- 13,084 residential lots owned directly, and 11,025 held under option (California and Virginia)
- 1,198 residential lots under development and 6,583 acres held for development (Colorado, Texas, Missouri)
- 10.8 million sq. ft. of commercial development

Renewable Power

- 99 renewable power plants
- 1,303 megawatts of installed capacity

Timberlands

- 0.7 million acres

Electricity Transmission

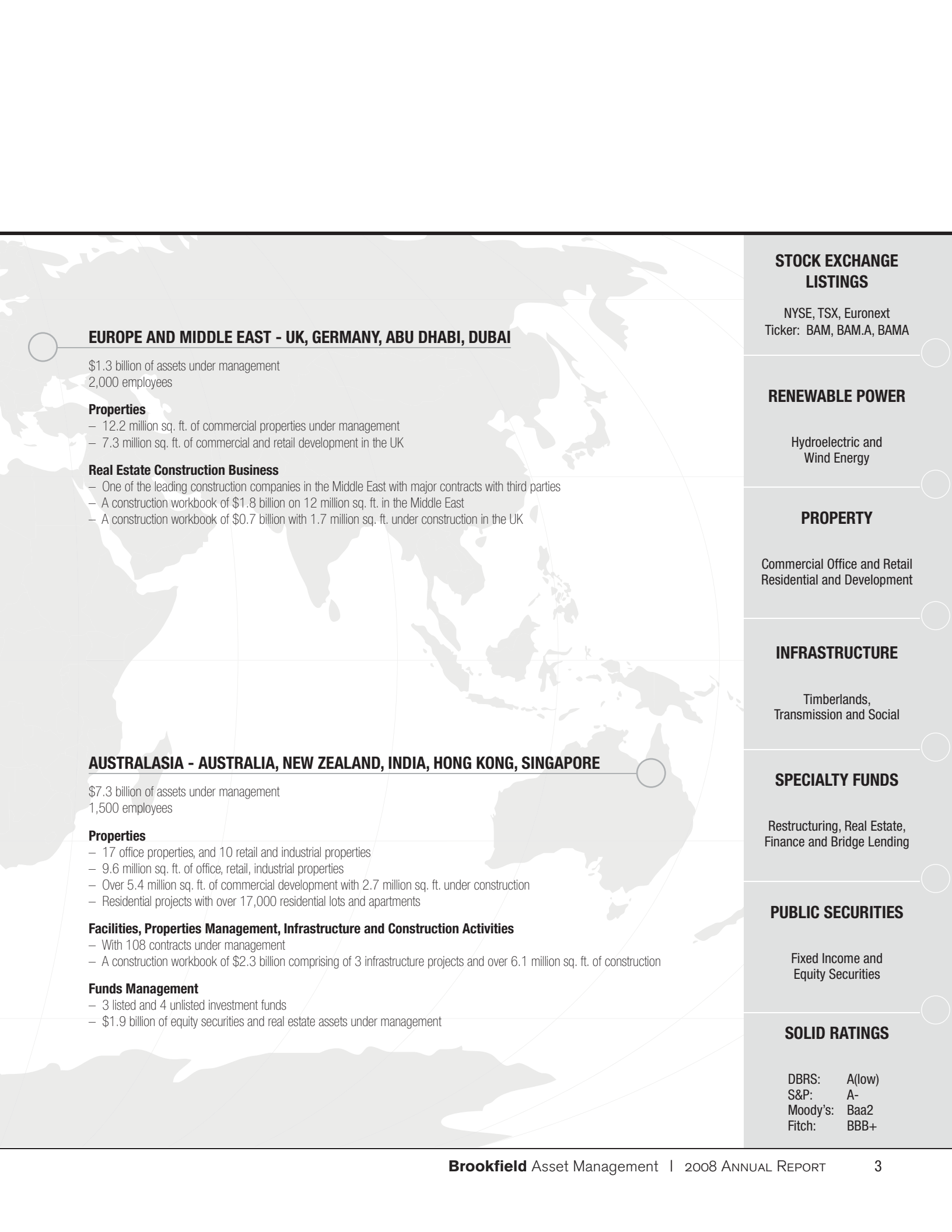
- Approximately 490 kilometres under planning

Specialty Funds

- \$2.8 billion of assets under management

Public Securities

- \$18.2 billion of fixed income and equity securities under management



EUROPE AND MIDDLE EAST - UK, GERMANY, ABU DHABI, DUBAI

\$1.3 billion of assets under management
2,000 employees

Properties

- 12.2 million sq. ft. of commercial properties under management
- 7.3 million sq. ft. of commercial and retail development in the UK

Real Estate Construction Business

- One of the leading construction companies in the Middle East with major contracts with third parties
- A construction workbook of \$1.8 billion on 12 million sq. ft. in the Middle East
- A construction workbook of \$0.7 billion with 1.7 million sq. ft. under construction in the UK

AUSTRALASIA - AUSTRALIA, NEW ZEALAND, INDIA, HONG KONG, SINGAPORE

\$7.3 billion of assets under management
1,500 employees

Properties

- 17 office properties, and 10 retail and industrial properties
- 9.6 million sq. ft. of office, retail, industrial properties
- Over 5.4 million sq. ft. of commercial development with 2.7 million sq. ft. under construction
- Residential projects with over 17,000 residential lots and apartments

Facilities, Properties Management, Infrastructure and Construction Activities

- With 108 contracts under management
- A construction workbook of \$2.3 billion comprising of 3 infrastructure projects and over 6.1 million sq. ft. of construction

Funds Management

- 3 listed and 4 unlisted investment funds
- \$1.9 billion of equity securities and real estate assets under management

STOCK EXCHANGE LISTINGS

NYSE, TSX, Euronext
Ticker: BAM, BAM.A, BAMA

RENEWABLE POWER

Hydroelectric and
Wind Energy

PROPERTY

Commercial Office and Retail
Residential and Development

INFRASTRUCTURE

Timberlands,
Transmission and Social

SPECIALTY FUNDS

Restructuring, Real Estate,
Finance and Bridge Lending

PUBLIC SECURITIES

Fixed Income and
Equity Securities

SOLID RATINGS

DBRS: A(low)
S&P: A-
Moody's: Baa2
Fitch: BBB+

Letter to Shareholders

OVERVIEW

2008 was unquestionably one of the most challenging years ever to be involved in the investment business. While everyone was affected, we avoided most of the investment mishaps experienced by many others, largely due to the type of long-duration hard assets we own. We also thankfully avoided the liquidity issues experienced by many, owing to our long-term, asset-specific, investment grade capital structure.

As a result, we were able to record strong cash flow from operations of \$1.4 billion or \$2.33 per share in 2008. This was one of our highest ever, although less than the total cash flows of the last few years because of a number of one-time items in the recent past. More importantly, these results display the sustainability of our core operating cash flows at a time when stable long-term cash flows are highly valued. The cash flow growth was due to solid performances from most of our operations, an increased contribution from our asset management activities and some realization gains. Net income was approximately \$649 million, and while not as relevant a measure for our business, was a solid result.

We believe many businesses are currently undervalued by the stock markets due to external factors, driven largely by liquidity concerns not necessarily relevant to the businesses. In fact, as we generate substantial free cash flow, the illiquidity of the markets is presenting us with investment opportunities, which over the longer term should enable us to earn returns far higher than we would normally expect.

We believe we are well positioned to capitalize on these opportunities as a result of our current cash position, available credit lines, the type of assets we own, the institutional relationships we have, and the contractual nature of the free cash flows we generate each year. Short-term fluctuations in our share price therefore have little effect on our business, because over the past 15 years we have seldom utilized our common shares to raise capital. Instead, we have been repurchasing shares at well below what we believe to be long-term net asset value.

And while some asset values in our operations have decreased from last year, we believe the declines in the stock market are far greater than the reductions in fundamental asset values. In this regard, it is important to note that none of our major operations has sustained irreparable harm to their businesses, no major dilutions have occurred in the ownership of the company or our investments (in fact the reverse occurred in some cases where we have been able to invest our free cash at exceptional values), our cash flows in

our renewable power operations are at record highs, and our office property leases are stable and of very long duration.

Despite this, we recognize the performance of our share price in the stock market was dismal, and as substantial shareholders ourselves, we empathize with you. Our share price ended the year down 56% which resulted in our worst share price performance in 20 years. This reduced the compound 20-year return, inclusive of dividends, to approximately 11% or approximately 3% higher than the compound 20-year returns of the principal North American stock indices.

Annualized Returns	Brookfield	S&P	TSX
YEARS			
1	-56.4%	-37.0%	-33.0%
5	12.7%	2.2%	4.2%
10	17.2%	1.4%	5.3%
20	10.6%	8.4%	7.5%

Focusing more specifically on our future, we currently have six operating priorities. These are similar to the priorities we have had in place for close to two years, and depending on how soon the world economic environment recovers, each may take on a different relative importance:

- Protect our businesses and asset values by constantly working our assets to enhance their value;
- Generate liquidity from non-strategic assets, and extend debt maturities before they come due;
- Maintain maximum financial and operating flexibility in order to be positioned for growth as markets turn;
- Repurchase interests held by others in our assets for less than net asset value, as a result of others holding a different view of long-term value;
- Position ourselves as a preferred sponsor of acquisition transactions, based on our operating abilities, reputation with institutional investors, and ability to commit capital; and
- Build client relationships with shared investment objectives.

MARKET ENVIRONMENT

Housing markets peaked in the U.S. in late 2005, the global credit markets began to deteriorate in July 2007, and a severe liquidity crisis manifested itself in September 2008. The global stimulus packages injected into the monetary system since then have been unprecedented and in time will lay the foundation for a recovery. As

a result, we believe that we have experienced most of the equity market correction likely to occur and that credit markets will continue to improve through 2009 and substantially recover in 2010. We also believe that while the recession will be deep, it will not get out of hand and that within another year or so, the necessary corrections will be behind us. Although our business plans are predicated on these expectations, we remain cautious having taken a number of actions and measures over the past 18 months to help strengthen our management of risk in this changing environment.

We are heartened to note that many of our institutional clients are now beginning to re-implement their investment strategies. The rush to the treasury market has reduced risk-free returns to negligible yields, and with most pension funds having earnings requirements of 7% or more on their portfolios, they are starting to put funds back to work. We believe that once they have fully reassessed their strategies, they will look to increase their investment in moderate risk, higher-yielding assets, such as the products we generally offer. This bodes well for our asset management business.

Fortunately, we have entered 2009 in a strong financial position. Our balance sheet strength and long-term investment horizons should play to our advantage as some owners of assets in need of capital are required to accept substantially reduced prices. And, as we have typically financed our investments with significant equity, usually comprising 50% of the purchase price, and financed the balance with fixed-rate, long-term investment grade financing, we are not as affected as many of our competitors who have relied on the more volatile high-yield debt markets to finance their business.

As a result of all of these factors, we believe that our businesses are, with few exceptions, well positioned to generate favourable returns even during these difficult economic circumstances and that they will continue to achieve our long-term objectives over the coming years.

Furthermore, we believe the next 24 months will present us with a very favourable period to invest capital in opportunities that should generate long-term returns well in excess of those returns typically expected on the low-risk type of assets which we prefer to own.

OPERATING PLATFORM AND BUSINESS STRENGTHS

We are fortunate that our businesses are, with only a few small exceptions, performing well, our operating cash flows are strong, and our capitalization and liquidity situation is good. It is in this regard that we review some key facts regarding our financial and operating situation.

Permanent capital at our disposal – First and foremost, we have approximately \$20 billion of permanent capital to support our overall operations. In today's environment, where many companies are without access to financing, this is a tremendous advantage. This capital does not come due and its trading price in the market has little direct impact on our operations.

Strong liquidity – Excluding institutional client funds, we currently have over \$3 billion of cash, financial equivalents and undrawn committed lines of credit to pursue opportunities. In the past 24 months we have generated more cash than we have invested or utilized in our operations. As a result, our capital availability today is greater than it was two years ago when the credit turbulence started to unfold, even though we have invested capital in a number of attractive investments during this period.

Significant annual free cash flow and capital turn-over – We generate approximately \$1.5 billion of free cash flow annually. This can be used largely in whatever fashion we choose. In addition, we traditionally turn over 10% of our invested capital annually, leading to a further \$2 billion or so to deploy. During the last six months, we generated close to \$1.5 billion of net cash from asset monetizations alone, which shows the flexibility within our operations to generate cash should we desire it.

Low parent company debt – We have only \$2.3 billion of debt at the parent company and, with few exceptions, do not guarantee our subsidiaries' debts. Our deconsolidated debt-to-capitalization ratio is 15%. As you also know, most of the debt within our businesses has recourse only to specific properties. If you proportionately consolidate all of our interests in assets, the debt to capitalization is 44%, well within investment grade. We would point out that sometimes these facts are not easily visible in our financial statements because of the requirement to consolidate debt within partially owned funds that is, in reality, attributable to our institutional partners. Please have a look at our supplemental disclosures and proportionate balance sheet should you wish to review this further.

Durable, long-term cash flows – The majority of our operations have durable cash flows and are long term in nature. To put this into perspective, please review the following points concerning our two largest operations:

Renewable Power Generation

- Average life of contracts – 12 years
- Average contract prices – nearly 90% are below the level required to support new capacity

- Average term of financing – 12 years
- Average financing ratio on asset values – 40%
- Average emissions of CO₂ – virtually nil
- Diversity of facilities – 162 hydroelectric generating plants on 64 river systems
- Ability to store water – equivalent to 22% of average annual generation output

Commercial Office Properties

- Average occupancy today – 97%
- Average annual lease rollover over next three years – 4%
- Average lease duration – over 7 years
- Average tenant quality – “A” rated
- Average net rent – 30% below current market
- Average financing on asset values – 50%
- Average duration of financing – 7 years

Institutional relationships – We also have access to substantial resources through our institutional relationships in the form of commitments to our current funds, funds we are raising, and with respect to co-investment opportunities. We feel fortunate to have this access on a global basis and as we continue to build these relationships, and demonstrate how our approach to investments has weathered the recent turmoil, the relationships should only get better.

Increasing number of opportunities to invest – We think there will be many opportunities to invest in areas where we have particular expertise. To date, we have chosen to be selective in the belief that better opportunities are still coming and that the best use of our cash in the meantime has been to repurchase interests in our own assets at discounts to their underlying values.

CAPITAL RAISING INITIATIVES IN 2008 AND FINANCING PROFILE

In furtherance of our strategy of recycling capital and pruning non-strategic assets, we completed a number of initiatives during 2008 which will generate net cash proceeds, over and above regular cash flows, of approximately \$1.5 billion after repayment of associated debt. The most notable of these transactions are as follows:

<i>MILLIONS</i>	<i>Gross</i>	<i>Net</i>
Sale of timberlands in the U.S. Northwest	\$ 1,200	\$ 590
Sale of 50% of Canada Trust Tower office property	400	190
Sale of Brazilian transmission lines	275	275
Sale of Hermitage and Image Insurance	350	350
Sale of 50% contracted wind facility and power plant	120	60
	\$ 2,345	\$ 1,465

- In October 2008, we sold part of our 588,000 acres of freehold lands owned in the U.S. Northwest to an institutional investment partnership that is managed by us and where we retain an approximate 40% direct and indirect interest. Total proceeds were \$1.2 billion, generating net cash to us of approximately \$600 million.
- In July, we sold our 50% interest in the Canada Trust office property in Toronto for C\$425 million. The sale generated net cash proceeds of approximately \$190 million, after repaying the mortgage.
- In September, we sold our transmission lines in Brazil for approximately \$275 million of net cash proceeds. The transaction is expected to close in the first quarter of 2009.
- In September, we reached agreement to sell two non-core insurance operations for \$350 million in cash. Approximately \$200 million was received in the fourth quarter of 2008, and the balance expected shortly.
- In December, we sold a wind facility and our interest in a small hydro power plant to our 50% owned hydro income fund. Net proceeds, after we subscribed for additional units of the fund, were approximately \$60 million.

In addition, we extended the terms of existing financings and raised new capital aggregating approximately \$8.0 billion during the year, largely in the form of asset-specific mortgages.

As noted earlier, we hold over \$3 billion of cash, financial equivalents and undrawn committed lines of credit within Brookfield. This includes approximately \$2 billion at the corporate level and approximately \$1 billion in our principal operating subsidiaries. Our only debt maturity at the corporate level before 2012 is a \$200 million bond which is due in late 2010, and our lines of credit extend into 2012. Our subsidiaries' debt is spread out among many of our operating units with diversified maturities and we believe that most, if not all of the debt should be refinanceable at current levels, even in difficult markets.

Our financing profile is based on asset-specific mortgages which, on average, represent approximately 50% loan-to-value. These mortgages have recourse only to our power plants, office properties, transmission lines and timber stands. We believe, based on our experience of renewing mortgages, even over the past year, that we should require very little further equity investment to extend the terms of these mortgages and it is likely that some of the renewals will generate opportunities for us to withdraw capital, particularly in the case of financings put in place a number of years ago.

Lastly, we think it is important for investors in Brookfield to understand the quality and the type of debt which we have, and the reason why Brookfield finances its affairs the way it does. First, our assets have highly stable cash flows and therefore each asset, in general, can support substantial non-recourse leverage and remain investment grade. This capital structure allows us to maximize returns on equity without taking on too much risk.

Our view is that the optimal leverage level for an asset or company depends on the type of assets it is supported by, and that the duration and covenants of the loan are as important as the amount of leverage itself. Used appropriately, we believe leverage can be positive; but as with everything, if utilized excessively or in the wrong way, leverage can destabilize a financial structure and amplify bad outcomes. Thankfully, due to our experience in operating these types of assets over many years, we have a healthy respect for the cyclical nature of markets and the level and type of leverage which is appropriate. As a result, while the past 18 months have been difficult for all investors, we have not had to face the major issues which a number of others have had to, mainly because we chose a different course as to the type and amount of leverage employed.

INVESTMENTS MADE DURING 2008

During 2008, we were cautious with the deployment of our capital. However, we did make a number of investments where we believe exceptional value will be earned in the long term. Most of these were internal opportunities where we were, in a number of different ways, increasing our interests in assets which we already own. The balance of our capital resources is sitting in cash and financial assets, or has been utilized to reduce debt, either to lower the leverage on some assets as we extended maturities or to repay bank lines which are now available to be drawn for investment in the future.

During the year, we invested approximately \$1.7 billion of cash in various ways. A good portion of this capital was invested in assets and shares of companies which we know well, and which

we believe were made at very substantial discounts to long-term underlying values.

<i>MILLIONS</i>	
Brookfield and subsidiary common shares	\$ 300
Hydroelectric power plants	350
Commercial office properties	300
U.S. residential assets	250
Brazilian residential assets	100
Value investment opportunities outside the above	400
	\$ 1,700

Brookfield and subsidiary common shares – We repurchased 14.2 million common shares of the company during the year at an average price of \$20.17. While we have been a substantial buyer over the past 10 years, we had not repurchased significant amounts in the two years prior to 2008 because the shares were trading at a price closer to intrinsic value and we believed our cash was better invested elsewhere. The reduction in our share price during 2008 presented us with a great opportunity to repurchase shares. During the year, we also invested approximately \$50 million to increase our interest in a number of our subsidiaries by repurchasing their shares in the open market.

Hydroelectric power plants – We acquired additional power plants for \$350 million, including a 156 megawatt high capacity facility in Brazil.

Commercial office properties – We invested \$300 million in commercial real estate, mostly through add-on acquisitions in our primary markets, by repurchasing interests held by partners in our properties, and through selective development.

U.S. residential assets – We have committed to acquire the majority of a \$250 million rights offering for convertible preferred of our U.S. residential operations. Our ultimate ownership interest, depending on minority shareholders' subscriptions, will be between 56% and 80%, on a fully-diluted basis.

Brazilian residential assets – We own approximately 42% of one of the most profitable homebuilders in Brazil. We have underwritten a rights offering to support the growth of this business which continues to be robust. This should ensure these operations maintain their competitive position as one of the top three builders in Brazil.

Value investment opportunities – We invested approximately \$200 million in a variety of value investment opportunities, both

directly and through our restructuring funds. We also subscribed for approximately \$200 million of shares in a Norbord rights offering to strengthen their balance sheet. This increased our interest from 36% to 80% on a fully-diluted basis.

GOALS AND STRATEGY

While many investors are understandably focused on the events of the next week or month, it is important to reiterate that our primary long-term goal is to achieve a compound 12% annual growth in our cash flows from operations measured on a per share basis. This should lead to an overall return of in excess of the 12% growth in cash flows after including the appreciation in the value of assets. This increase will not occur consistently each year (and some years will decrease), but we believe we can achieve this objective over the longer term by continuing to focus on four key operating strategies:

- Build a world-class asset management firm, offering a focused group of products on a global basis for our investment partners.
- Differentiate our product offerings by utilizing our operating experience and our extended investment horizons, to generate greater returns over the long term for our partners.
- Focus our products on simple to understand, high quality, long-life, cash-generating physical assets that require minimal sustaining capital expenditures and have some form of barrier to entry, characteristics which should lead to appreciation in the value of these assets over time.
- Maximize the value of our operations by actively managing our assets to create operating efficiencies, lower our cost of capital and enhance cash flows. Given that our assets generally require a large initial capital investment, have relatively low variable operating costs, and can be financed on a long-term, low-risk basis, even a small increase in the top-line performance typically results in a much more meaningful contribution to the bottom line.

We believe we can continue to successfully grow our global asset management business, because underlying fundamentals for asset management, particularly within the infrastructure and real asset area, continue to be positive. In fact, in an uncertain world, we believe our lower-risk, lower-volatility assets should become even more appealing, especially as investors reprice risk in the marketplace.

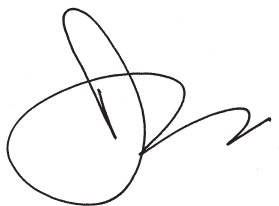
SUMMARY

We remain committed to building a world-class asset manager, and investing capital for you and our investment partners in high-quality, simple-to-understand assets which earn a solid cash-on-cash return on equity, while always emphasizing downside protection of the capital employed.

The primary objective of the company continues to be generating increased cash flows on a per share basis, and as a result, higher intrinsic value over the longer term.

It is always important to remind ourselves that there may be occasional periods of time, maybe years, when stock market values, for various reasons, may not reflect the intrinsic value of the underlying business. This reality presents opportunities to acquire assets in the public market at less than intrinsic value, but can similarly affect your shareholdings in our company for periods of time. This is particularly acute today, and while we are not pleased with this, we hope to be able to capitalize on further opportunities should this environment persist and therefore at least turn these short-term market disruptions into long-term positives for you.

And, while I personally sign this letter, I respectfully do so on behalf of all of the members of the Brookfield team, who collectively generate the results for you. Please do not hesitate to contact any of us, should you have suggestions, questions, comments, or investment ideas.



J. Bruce Flatt
*Senior Managing Partner and
Chief Executive Officer*
February 13, 2009

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report to Shareholders contains forward-looking information within the meaning of Canadian provincial securities laws and other “forward-looking statements” within the meaning of certain securities laws including Section 27A of the U.S. Securities Act of 1933, as amended, Section 21E of the U.S. Securities Exchange Act of 1934, as amended, “safe harbor” provisions of the United States Private Securities Litigation Reform Act of 1995 and in any applicable Canadian securities regulations. We may make such statements in this report, in other filings with Canadian regulators or the SEC or in other communications. The words “bodes”, “presents”, “enable”, “enhance”, “maintain”, “traditionally”, “in time”, “objective”, “growth”, “deploy”, “become”, “sustain”, “pursue”, “generate”, “think”, “raising”, “build”, “capitalize”, “beginning”, “create”, “largely”, “continue”, “believe”, “typically”, “expect”, “potentially”, “encourage”, “tend”, “primarily”, “generally”, “represent”, “anticipate”, “position”, “goal”, “likely”, “pending”, “might”, “hope”, “intend”, “estimate”, “expand”, “scheduled”, “endeavour”, “seeking”, “usually”, “often” derivations thereof and other expressions of similar import, or the negative variations thereof, and similar expressions of future or conditional verbs such as “may”, “will”, “can”, “should”, “likely”, “would” or “could” are predictions of or indicate future events, trends or prospects and which do not relate to historical matters or identify forward-looking statements. Forward-looking statements in this Annual Report include, among others, statements with respect to maximizing our returns on equity, maintaining our operating flexibility, repurchasing our assets, generating long-term returns on assets, differentiating our product offering, building and improving client relationships, furthering our goal of building a world class asset management firm, protecting our businesses and asset values, executing our business strategy, increasing our intrinsic value, positioning ourselves as a preferred sponsor of acquisition transactions, the ability of our assets to support non-recourse leverage and remain investment grade, the ability of our Brazilian residential assets to maintain a competitive position, the recovery of the monetary system and future market and economic environment, our ability to generate favourable returns during difficult economic circumstances, our ownership interest in our U.S. residential operations, future investments of institutional clients, procedures and assumptions that we intend to follow in preparing our pro forma opening balance sheet for our adoption of International Financial Reporting Standards (“IFRS”), the duration we intend to hold most of our assets, our financial and operating objectives and strategies to achieve them, capital committed to our funds, potential growth of our asset management business and related revenue streams therefrom, our core liquidity levels, the likelihood that our commercial property rents will be paid, the strength of our tenant relationships, commencement of commercial operations at our new hydroelectric facilities in Brazil, changes in long-term power prices and the effect thereof on operating expenses and borrowing costs, the expected closings during the first quarter of 2009 of the sale of our interest in transmission lines in Brazil and our United Kingdom reinsurance business within Imagine Insurance and recovery of capital from the balance of the Imagine business, residential construction levels in relation to our Brazilian operations, residential construction margins in relation to our Australian operations, scheduled occupancy of the Bay Adelaide Centre in Toronto, construction of commercial office space on Ninth Avenue in New York City, future growth of our residential development properties, the underlying value of our development assets, expected returns from disposition gains in our restructuring funds, future income tax rates, future realization gains, planned expansion of our transmission operations, the impact of the current downturn in the economy on operating margins and opportunities, our ability to create value for our shareholders and clients, enhance the long-term value of our existing businesses, capitalize on future opportunities, achieve strong performance in our power generating operations, maintain or increase our net rental income, contract power into the future, generate revenue and margin from our transmission operations, attract new tenants for our commercial properties, pre-lease our commercial office properties under development, convert our rural development properties into residential and other purpose land, finance our assets and operations on a long-term basis and repay or refinance debt maturities, expand our infrastructure activities into new sectors, maintain the necessary level of liquidity to manage our financial commitments and capitalize on opportunities, as well as the outlook for the company’s businesses and other statements with respect to our beliefs, outlooks, plans, expectations and intentions.

Although Brookfield believes that the anticipated future results, performance or achievements expressed or implied by the forward-looking statements and information are based upon reasonable assumptions and expectations, the reader should not place undue reliance on forward-looking statements and information because they involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the company to differ materially from anticipated future results, performance or achievement expressed or implied by such forward-looking statements and information.

Factors that could cause actual results to differ materially from those contemplated or implied by forward-looking statements include: economic and financial conditions in the countries in which we do business; the behaviour of financial markets, including fluctuations in interest and exchange rates; availability of equity and debt financing; strategic actions including dispositions; the ability to effectively integrate acquisitions into existing operations and the ability to attain expected benefits; the company’s continued ability to attract institutional partners to its specialty funds; adverse hydrology conditions; timber growth cycles; environmental matters; regulatory and political factors within the countries in which the company operates; acts of God, such as earthquakes and hurricanes; the possible impact of international conflicts and other developments including terrorist acts; changes in accounting policies to be adopted under IFRS; and other risks and factors detailed from time to time in the company’s form 40-F filed with the Securities and Exchange Commission and Management’s Discussion and Analysis of Financial Results as well as other documents filed by the company with the securities regulators in Canada and the United States.

We caution that the foregoing list of important factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Brookfield, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Except as may be required by law, the company undertakes no obligation to publicly update or revise any forward-looking statements or information, whether written or oral, that may be as a result of new information, future events or otherwise.

CAUTIONARY STATEMENT REGARDING USE OF NON-GAAP ACCOUNTING MEASURES

This Annual Report makes reference to cash flow from operations on a total and per share basis. Management uses cash flow from operations as a key measure to evaluate performance and to determine the underlying value of its businesses. Brookfield’s consolidated statements of cash flow from operations provides a full reconciliation between this measure and net income. Readers are encouraged to consider both measures in assessing Brookfield’s results. Operating cash flow is not a generally accepted accounting principle measure and differs from net income, and may differ from definitions of operating cash flow used by other companies. We define operating cash flow as net income prior to such items as depreciation and amortization, future income tax expense and certain non-cash items that in our view are not reflective of the underlying operations.

Management's Discussion and Analysis of Financial Results

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PART 1 – INTRODUCTION

The information in Management's Discussion and Analysis of Financial Results ("MD&A") should be read in conjunction with our audited consolidated financial statements, which are included on pages 79 through 111 of this report. Additional information, including the company's Annual Information Form, is available on the Corporation's web site at www.brookfield.com and on SEDAR's web site at www.sedar.com. For additional information on each of the five most recently completed financial years, please refer to the table on page 112 of this report.

BUSINESS OVERVIEW

Brookfield is a global asset management company, with a primary focus on property, power and infrastructure assets. We have established leading operating platforms in these sectors and, through them, own and manage a broad portfolio of high quality assets that generate long-term cash flows and opportunities to create value for our shareholders and our clients. We create value for shareholders by increasing, over time, the cash flows generated by these assets as well as income earned from managing the capital invested by our clients alongside our own.

BASIS OF PRESENTATION

We have organized the MD&A on a basis that is consistent with how we operate the business. We organize our activities into individual Operating Platforms which focus on a specific business segment. These platforms include commercial properties, power generation, infrastructure, development and other properties, specialty funds and public securities.

We use operating cash flow as a key measure of our financial performance. This is not a generally accepted accounting principle ("GAAP") measure and differs from net income, and may differ from definitions of operating cash flow used by other companies. We define operating cash flow as net income prior to such items as depreciation and amortization, future income tax expense and certain non-cash items that in our view are not reflective of the underlying operations. We provide this measure to investors as a measurement tool which we believe assists in analysis of the company, in addition to other traditional measures, which we also provide. We recognize the importance of net income as a GAAP measure to investors and provide a full reconciliation between these measures.

We present invested capital and operating cash flows on both a "total" and "net" basis. The "total" basis is similar to our consolidated financial statements with the exception that the assets and cash flows are organized by operating platforms. Total operating cash flow includes revenues from our operating platforms less direct operating costs, together with fees earned and investment and other income.

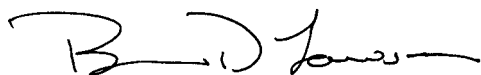
Net invested capital and net operating cash flows represent our pro rata interest in the underlying net assets and cash flows. They are, with the exception of the operations of Brookfield Properties Corporation, presented on a deconsolidated basis meaning that assets are presented net of associated liabilities and non-controlling interests. Similarly, cash flows are represented net of carrying charges associated with related liabilities and cash flow attributable to related non-controlling interests. Net invested capital and net operating cash flow are therefore representative of the amount of capital invested by us in each operation or fund and the operating cash flow that we are entitled to from the underlying activities. Furthermore, in our view, this presentation provides a more consistently comparable basis of presentation than our consolidated financial statements which include our operations under various methods, including equity accounting, proportionate consolidation and full consolidation.

We provide reconciliations between the basis of presentation in our MD&A and our consolidated financial statements in the tables on pages 54 and 55 and the accompanying discussion. We specifically reconcile operating cash flow and net income on page 39.

Assets under management include assets managed by us on behalf of our clients, as well as our own assets. We invest capital alongside our clients in many of our funds, and we continue to own a number of assets that we acquired prior to the formation of our asset management operations and are therefore not part of any fund. Assets under management include the assets reflected in our consolidated financial statements and, as a result, are based on book values that may differ materially from current market values, particularly in the case of long-life assets that we have owned for many years. Assets under management also include capital commitments that have not yet been drawn. Our calculation of assets under management may differ from that employed by other asset managers and, as a result, this measure may not be comparable to similar measures presented by other asset managers.

Co-investor commitments represent capital that has been committed to us to invest on behalf of the client. We typically earn base management fees on this capital from the time that the commitment to the fund is effective, during the period of time until the capital is invested (commonly referred to as the investment period) until such time as the investments are monetized and the capital returned to the client. Committed capital includes invested capital and commitments that have not yet been invested. Uninvested commitments represent capital available to us to invest and form part of our overall liquidity for these purposes.

Unless the context indicates otherwise, references in this MD&A to the "Corporation" refer to Brookfield Asset Management Inc., and references to "Brookfield" or "the company" refer to the Corporation and its direct and indirect subsidiaries and consolidated entities. All financial data included in the MD&A has been prepared in accordance with Canadian GAAP and specified non-GAAP measures unless otherwise noted. All figures are presented in U.S. dollars, unless otherwise noted.



Brian D. Lawson
Managing Partner and Chief Financial Officer

February 13, 2009



Sachin G. Shah
Senior Vice President, Finance

PART 2 – PERFORMANCE REVIEW

SUMMARY

We achieved solid performance during 2008, notwithstanding the difficult economic environment, and undertook a number of initiatives to protect and enhance the long-term value of our existing businesses and to better position the company to capitalize on opportunities that we expect will arise in the coming years.

Our financial results reflected the strong performance from our two largest business units, renewable power generation and commercial office properties. These results more than offset the lower cash flows generated from some of our smaller business units.

Our conservative approach to financing enables us to concentrate on running our businesses and executing our business strategies. We maintain substantial financial liquidity and finance our operations primarily at the asset level on a long-term, investment grade, non-recourse basis. During the year, we were successful in refinancing many of our near-term maturities with longer-dated debt to extend our maturity profile. Finally, the flexibility inherent in our asset base and our continued access to capital enabled us to further enhance our liquidity position.

Operating Cash Flow

Operating cash flow totalled \$1.4 billion for the year compared with \$1.9 billion in 2007 and \$1.8 billion in 2006. On a more comparable basis, which excludes major disposition gains, operating cash flow was \$1.2 billion or \$1.98 per share compared with \$1.1 billion or \$1.79 per share in 2007, representing an 8% increase.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS, EXCEPT PER SHARE AMOUNTS)

	2008	2007	2006
Operating cash flow			
Total	\$ 1,423	\$ 1,907	\$ 1,801
– per share	2.33	3.11	2.95
Excluding major disposition gains	1,214	1,120	1,191
– per share	1.98	1.79	1.93

Our power generating operations produced net operating income prior to debt service of \$886 million, a record for this business and a significant increase over the \$611 million generated in 2007. This increase was due to increased water flows and higher realized prices. We have locked in prices at attractive levels for approximately 75% of our power sales over the next two years and therefore we expect to achieve continued strong performance, assuming water flows are consistent with long-term averages.

Our office properties produced solid and stable results during 2008. Net operating cash flow increased to \$782 million from \$583 million due to increases in rental income from existing properties, the contribution from recently acquired properties and disposition gains. The overall occupancy level of the properties was 97% at year end, with an average lease term of seven years with high quality tenants and average in-place rents that are, by our estimation, 30% below comparable average market rents.

The strong performance of these two businesses provided significant stability to our results during the difficult economic environment of 2008, and the stable contracted revenue profiles of these businesses provide us with a high level of visibility and confidence for 2009 and 2010, and confidence in our ability to achieve our long-term objectives in future years as well.

Balance Sheet, Liquidity and Capitalization

We undertook a number of measures to strengthen our liquidity and capitalization. In aggregate, we completed \$8 billion of financings during the year to extend existing maturities and provide liquidity to pursue business opportunities.

Our net invested capital is financed with a substantial equity base and only modest amounts of corporate borrowings.

AS AT DECEMBER 31, 2008 (MILLIONS, EXCEPT PER SHARE AMOUNTS)	Shareholders' Equity	
	Total	Per share
Underlying value – excluding future taxes	\$ 15,021	\$ 24.32
Underlying value – including future taxes	12,801	20.62
Book value	5,788	8.93

At the corporate level, we extended \$1.2 billion of our revolving credit facilities until 2012, with the remaining \$0.2 billion not due until 2011. We also refinanced the one debt maturity that we had, of \$300 million, with C\$150 million of perpetual preferred shares and a \$150 million private placement of notes with an average term of 4.3 years. We have no maturities at the corporate level until March 2010.

Our core liquidity is approximately \$3.5 billion at the date of this report, up from \$2.8 billion at the beginning of 2008, of which \$1.8 billion is at the corporate level, \$1.0 billion is at our principal operating platforms and \$0.7 billion is under contract or has been received since year end.

The underlying values presented in this MD&A are prepared using the procedures and assumptions that we intend to follow in preparing our pro forma opening balance sheet for our adoption of International Financial Reporting Standards (“IFRS”). Accordingly, the underlying values reflect most of our tangible assets at fair value as of the balance sheet date, with corresponding adjustments to minority interests and shareholders’ equity, but do not include any adjustments to reflect value attributable to our asset management franchise and do not reflect any upward revaluation of inventories to reflect current value. We have not adjusted the carrying values of our borrowings at this time. The underlying values are reduced by accounting provisions in respect of the theoretical tax liability that might arise if we were to liquidate the business based on the underlying values at the balance sheet date, consistent with IFRS accounting principles. Our intention, however, is to hold most of our assets for extended periods of time or otherwise defer this liability. The deferred tax balance is similar in this sense to the float in an insurance company which is available for investment for extended periods of time or even indefinitely. Accordingly, we also provide our underlying values on a pre-tax basis because, in our opinion, these are more reflective of the capital that is actually deployed on behalf of shareholders.

Net Income

The following table presents net income for the past three years determined in accordance with Canadian GAAP. We do not utilize net income as a key metric in assessing the performance of our business because, in our view, it contains measures that may distort the ongoing performance and intrinsic value of the underlying operations. Nevertheless we recognize the importance of net income as a key measure for many users and provide a discussion of net income and a reconciliation to operating cash flow in this review.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS, EXCEPT PER SHARE AMOUNTS)	2008	2007	2006
Net income			
Total	\$ 649	\$ 787	\$ 1,170
– per share	1.02	1.24	1.90
Excluding major disposition gains	525	349	624
– per share	0.81	0.51	0.99

Net income excluding major disposition gains increased to \$525 million from \$349 million on a comparable basis. In total, after taking major disposition gains into consideration, net income was lower than in 2007 due to a higher level of gains in prior years.

The increase on a comparable basis reflects the growth in operating cash flow discussed above, offset by a higher level of non-cash items. In particular, we recorded increased depreciation relating to a large office property portfolio acquired in 2007 as well as the revaluation for accounting purposes of certain hedging transactions. These items were partially offset by non-cash tax credits that reflect the increased value of our tax assets and a reduction in anticipated future taxes payable.

Performance Metrics

Annualized growth over the last five years was 16% excluding major disposition gains and 20% including such items, which exceeds our long-term objective.

FOR THE YEARS ENDED DECEMBER 31	Long-term Objective	Five-Year Results	Annual Results				
			2008	2007	2006	2005	2004
Operating cash flow per share							
– excluding major disposition gains	12%	16%	\$ 1.98	\$ 1.79	\$ 1.93	\$ 1.46	\$ 1.03
– total	12%	20%	\$ 2.33	\$ 3.11	\$ 2.95	\$ 1.46	\$ 1.03

The following table presents our cash return on equity, based on our operating cash flow as a percentage of average common shareholders' equity at book values:

FOR THE YEARS ENDED DECEMBER 31	Long-term	Five-Year	Annual Results				
	Objective	Results	2008	2007	2006	2005	2004
Cash return on book equity per share	20%	26%	23%	30%	34%	21%	19%

We achieved a 23% cash return on equity during 2008 and a 26% average return over the past five years. We exceeded our target by a considerable amount in 2007 and 2006 due to the higher level of disposition gains recorded in those years.

Asset Management Activities

We continued to expand our asset management activities during the year, increasing the number of funds, third-party capital under management and associated management fees. The following table presents key metrics relating to our asset management activities over the past three years:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007	2006
Asset management revenues	\$ 449	\$ 415	\$ 257
Base management and performance returns	140	112	71
Third-party capital commitments			
– Unlisted fund and specialty issuers	9,174	7,996	5,722
– Fixed income and real estate securities	18,040	26,237	20,460

Asset management revenues increased by 8% due to a higher level of base management fees, which increased by \$30 million or 29%. The increase in base management fees reflects the growth in higher margin funds and capital under management, which offset the impact of lower fixed income and equity securities, which typically pay lower fees.

Capital committed by third-party clients to our unlisted funds and specialty issuers increased by \$1.2 billion, however this was more than offset by a reduction in the value of assets under management within our fixed income and real estate securities management operations. Assets under management as measured in U.S. currency was also impacted by changes in foreign currency exchange rates on non-U.S. assets under management.

Summary of Financial Results

The following table summarizes our underlying values, net invested capital and net operating cash flows from our operations over the past two years:

	<i>Underlying Value</i>	<i>Net Invested Capital</i>		<i>Net Operating Cash Flow</i>	
<i>AS AT AND FOR THE YEARS ENDED DECEMBER 31</i>					
<i>(MILLIONS, EXCEPT PER SHARE AMOUNTS)</i>	<i>2008</i>	<i>2008</i>	<i>2007</i>	<i>2008</i>	<i>2007</i>
Asset management income				\$ 449	\$ 415
Operating platforms					
Commercial properties	\$ 7,798	\$ 4,575	\$ 4,598	763	602
Power generation	6,639	1,215	1,425	466	261
Infrastructure	974	761	1,645	141	102
Development and other properties	3,313	3,334	3,464	205	301
Specialty funds	903	870	1,112	126	341
Investments	701	702	1,336	180	312
Cash and financial assets	1,073	1,073	892	487	693
Other assets	2,650	2,568	3,013	—	—
	\$ 24,051	\$ 15,098	\$ 17,485	\$ 2,817	\$ 3,027
Liabilities					
Corporate borrowings	\$ 2,284	\$ 2,284	\$ 2,048	\$ 163	\$ 146
Subsidiary borrowings	733	733	711	77	66
Capital securities	1,425	1,425	1,570	88	90
Other liabilities	3,267	2,654	3,482	616	450
	7,709	7,096	7,811	944	752
Capitalization					
Co-investor interests in consolidated operations	3,541	2,214	2,160	450	368
Preferred equity	870	870	870	44	44
Common equity	11,931	4,918	6,644	1,379	1,863
	16,342	8,002	9,674	1,873	2,275
	\$ 24,051	\$ 15,098	\$ 17,485	\$ 2,817	\$ 3,027
Per Share					
— including future tax liability	\$ 20.62	\$ 8.93	\$ 11.64	\$ 2.33	\$ 3.11
— excluding future tax liability	\$ 24.32				

The table above includes the assets, liabilities and operating results of our North American property company, Brookfield Properties Corporation (“Brookfield Properties”), on a consolidated basis, with interests of minority shareholders in these operations presented as “co-investor interests in consolidated operations”.

The common shareholders’ equity, on an underlying value basis, is presented in the following table prior to and after reflecting accounting provisions for future tax liabilities.

AS AT DECEMBER 31, 2008

(MILLIONS, EXCEPT PER SHARE AMOUNTS)

	<i>Total</i>	<i>Per Share</i>
Common equity – including future tax liability	\$ 11,931	\$ 20.62
Add back: future tax liability	2,220	3.70
Common equity – excluding future tax liability	\$ 14,151	\$ 24.32

We provide a detailed review of the invested capital and operating cash flows on both a consolidated basis, as well as on a net basis as presented above, in the balance of the Performance Review contained on the following pages. We also provide a reconciliation between operating cash flows and net income beginning on page 39 and a reconciliation to our consolidated financial statements beginning on pages 54 and 55.

OPERATING PLATFORMS

Commercial Properties

We own and operate high quality commercial office and retail properties on behalf of ourselves and our co-investors in North America, Australasia, Europe and Brazil.

The following table summarizes the invested capital and operating cash flows contributed by our commercial property operations:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Consolidated		Net Invested		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Office properties	\$19,657	\$20,922	\$4,485	\$4,495	\$1,773	\$1,518	\$782	\$583
Retail properties	1,326	1,698	90	103	110	48	(19)	19
	\$20,983	\$22,620	\$4,575	\$4,598	\$1,883	\$1,566	\$763	\$602
Underlying value	\$23,877		\$7,798					

Office Properties

We own and manage one of the highest quality commercial office portfolios in the world located in major financial, energy and government centre cities in North America, Australasia and Europe. Our strategy is to concentrate our operations in high growth, supply-constrained markets that have high barriers to entry and attractive tenant bases. Our goal is to maintain a meaningful presence in each of our primary markets so as to build on the strength of our tenant relationships.

AS AT DECEMBER 31, 2008	# of Properties	Total Area (000's Sq ft)	Consolidated Owned Interest (000's Sq ft)
North America			
U.S.	79	54,177	46,975
Canada	29	20,258	20,258
	108	74,435	67,233
Australasia	27	9,581	6,829
Europe			
Canary Wharf, London U.K.	16	7,900	1,185
Direct	2	732	644
	18	8,632	1,829
Total portfolio	153	92,648	75,891

Our North American operations are conducted through a 51%-owned subsidiary, Brookfield Properties, and our primary markets are New York, Boston, Houston, Los Angeles, Washington D.C., Toronto, Calgary and Ottawa. We also own a high quality portfolio of properties in Australia located primarily in Sydney, Brisbane, Melbourne and Perth. Our European operations are principally located in London, U.K. The properties in each of these geographic areas are held directly as well as through funds which we manage on behalf of ourselves and others on a contractual basis.

The following table sets out the consolidated assets and net capital invested in our office property operations by region:

AS AT DECEMBER 31 (MILLIONS)	2008				2007			
	Consolidated Assets	Consolidated Liabilities	Co-Investor Interests	Net Invested Capital	Consolidated Assets	Consolidated Liabilities	Co-Investor Interests	Net Invested Capital
Office properties								
North America	\$7,887	\$5,675	\$—	\$2,212	\$8,737	\$6,297	\$—	\$2,440
U.S. Core Office Fund	7,395	5,729	923 ¹	743	7,247	5,502	955 ¹	790
Australasia	2,458	1,283	102	1,073	2,927	2,077	127	723
Europe	986	642	—	344	796	561	—	235
Working capital	931	818	—	113	1,215	908	—	307
	\$19,657	\$14,147	\$1,025	\$4,485	\$20,922	\$15,345	\$1,082	\$4,495

¹ Includes \$711 million (2007 – \$739 million) of co-investor interests that are classified as liabilities for accounting purposes

Consolidated office property assets decreased from \$20.9 billion to \$19.7 billion. Consolidated assets and liabilities within our Canadian and Australian operations declined due to lower currency exchange rates and property sales. Net invested capital in all regions was relatively unchanged. The consolidated carrying value of our North American properties is approximately \$221 per square foot, substantially less than the estimated replacement cost of these assets.

During the year we completed \$1.2 billion of financings to refinance existing properties. Core office property debt at December 31, 2008 had an average interest rate of 5.6% and an average term to maturity of seven years.

Working capital assets include rents receivable as well as a portion of the purchase price of properties totalling \$841 million that has been attributed to items such as above-market leases and tenant relationships. Similarly, working capital liabilities include \$760 million in respect of items such as below-market tenant and land leases.

The following table shows the sources of operating cash flow by geographic region:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flow							
	2008				2007			
	Total	Interest Expense	Co-investor Interests	Net	Total	Interest Expense	Co-investor Interests	Net
North America	\$1,485	\$ 673	\$ 97 ¹	\$ 715	\$ 1,416	\$ 718	\$ 125 ¹	\$ 573
Australasia	213	178	9	26	62	57	—	5
Europe	75	34	—	41	40	34	1	5
	\$1,773	\$ 885	\$ 106	\$ 782	\$ 1,518	\$ 809	\$ 126	\$ 583

¹ Includes \$23 million (2007 – \$55 million) attributable to co-investor interests classified as liabilities and interest expenses for accounting purposes

The following table sets out the variances in operating cash flows:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	Total 2007	Variance
Same properties	\$ 1,323	\$ 1,301	\$ 22
Acquired properties	268	62	206
Dividend from Canary Wharf	31	—	31
Disposition gains	164	145	19
Other	(13)	10	(23)
Total operating cash flow	1,773	1,518	255
Interest expense and co-investor interests			
– Existing properties	(793)	(878)	85
– Acquired properties	(198)	(57)	(141)
Net operating cash flow	\$ 782	\$ 583	\$ 199

We leased 6.4 million square feet in our North American portfolio during 2008 at an average net rent of \$25.44 per square foot, replacing expiring leases that averaged \$17.80 per square foot, leading to increased rent. We continue to manage our portfolios and tenant relationships on a proactive basis which can lead to opportunities to re-lease space for increased yields while minimizing vacancies.

Property acquisitions were responsible for most of the increase in operating cash flows, which is to be expected given the stable nature of our long-term lease portfolio and the high credit quality of our tenants. The increase was \$65 million on a net basis after taking incremental borrowing costs into consideration. The Australian portfolio contributed total operating cash flows of \$213 million (2007 – \$62 million) and net operating cash flows of \$26 million (2007 – \$5 million).

The disposition gains occurred largely in our North American portfolio and in 2008 included \$164 million from the sale of a partial interest in the Canada Trust office property in Toronto while the 2007 results reflect the sale of non-core properties in Washington D.C., Toronto and Ottawa.

Interest expense and co-investors' interests decreased by \$85 million over 2007 due largely to the impact of lower interest rates on floating rate debt. Interest expense on borrowings associated with acquisitions increased by \$141 million.

Leasing Profile

Our total portfolio worldwide occupancy rate at the end of 2008 increased to 97% compared to 96% at December 31, 2007, and the average term of the leases was seven years, unchanged from the prior year.

AS AT DECEMBER 31, 2008	Current	Average	Net Rental	Currently	Expiring Leases (000's Sq ft)						
	Occupancy	Term	Area	Available	2009	2010	2011	2012	2013	2014	2015+
Core North American markets											
United States	96%	7.0	46,975	2,002	1,397	1,650	2,797	3,432	7,745	3,141	24,811
Canada	99%	7.1	18,620	179	528	933	1,199	1,230	3,111	400	11,040
Other North American	99%	7.5	1,638	21	41	181	142	90	104	45	1,014
United Kingdom	92%	18.9	644	53	—	—	35	—	—	—	556
Australasia	99%	7.6	6,829	46	360	367	334	279	276	343	4,824
Total/Average	97%	7.2	74,706	2,301	2,326	3,131	4,507	5,031	11,236	3,929	42,245
Percentage of Total			100%	3%	3%	4%	6%	7%	15%	5%	57%

As at December 31, 2008, the average term of our in-place leases in North America was seven years. Annual lease expiries average 4% over the next four years with only 3% expiring in 2009. Average in-place net rents across the portfolio have remained unchanged at \$23 per square foot from the end of last year, and continue to be at a significant discount to the average market rent of \$32 per square foot. This discount provides greater assurance that we will be able to maintain or increase our net rental income in the coming years, notwithstanding the present difficult economic environment.

Average in-place rents in our Australian portfolio are \$34 per square foot, approximately 10% below market rents. During the year we leased 1.3 million square feet of space at higher rates than the expiring leases. The occupancy rate across the portfolio remains high at 99.3% and the weighted average lease term is approximately eight years. Our fifteen largest tenants have a weighted average lease life of nine years and account for approximately 70% of our leaseable area. These tenants have an average rating profile of A+.

The high quality of our properties has enabled us to sign long-term leases with high quality tenants that have strong credit profiles. The contractual terms of these leases provide a high level of assurance that rents will be paid as expected unless a bankruptcy event occurs. Notwithstanding the recent economic turmoil, only 400,000 square feet, representing less than 1% of our net rentable area and annualized net operating income of \$3.5 million, were returned to us as a result of credit events, and we subsequently re-leased 110,000 square feet of this space at equivalent or better rents. Furthermore, the competitive positions of our properties in their respective markets enable us to attract new tenants from lower quality buildings to fill any excess in vacant space and we are in active negotiations to lease the remainder of the space returned.

Retail

Our Brascan Brasil Real Estate Partners Fund was formed in late 2006 and has \$830 million of committed capital (Brookfield's share – 25%). The fund is almost fully invested with \$1.3 billion of total assets representing one of the largest retail portfolios in Brazil. The portfolio consists of interests in 15 shopping centres and associated office space totalling 4.1 million square feet of net leasable area, located primarily in Rio de Janeiro and São Paulo as well as Curitiba, Belo Horizonte, Mogi das Cruzes and Piracicaba.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Retail properties	\$ 962	\$ 1,489	\$ 962	\$ 1,489	\$ 110	\$ 48	\$ 110	\$ 48
Working capital/operating costs	364	209	(136)	(662)			(15)	(10)
Borrowings/interest expense			(614)	(462)			(125)	(6)
Co-investor interests			(122)	(262)			11	(13)
	\$ 1,326	\$ 1,698	\$ 90	\$ 103	\$ 110	\$ 48	\$ (19)	\$ 19

Total operating cash flows increased to \$110 million in 2008 compared to \$48 million in 2007. The increase reflects the contribution from properties acquired in late 2007 and higher sales within existing properties. Many of the properties were undergoing significant redevelopment during the year, which reduced net rent and increased costs. Net operating cash flow also reflects integration and borrowing costs associated with the acquired assets. The 2007 results reflect a disposition gain of \$8 million.

The declines in consolidated assets and net invested capital are due primarily to the impact of lower currency exchange rates. Borrowings also include \$121 million of debt incurred by the fund to finance the purchase of the initial portfolio assets, which is guaranteed by the obligations of ourselves and our partners to subscribe for capital in the fund equal to the outstanding balance.

Underlying Value

The underlying values of the consolidated assets and net equity of our commercial portfolio were determined to be \$23.9 billion and \$7.8 billion, respectively, as at December 31, 2008. The key metrics used in each geographic region are set out in the following table:

	North America			Australia			United Kingdom		
	Minimum	Maximum	Average	Minimum	Maximum	Average	Minimum	Maximum	Average
Discount rate	6.5%	13.0%	8.2%	6.3%	9.4%	7.0%	5.5%	8.5%	6.2%
Terminal capitalization rate	5.7%	9.0%	6.9%	8.5%	11.0%	8.9%	5.5%	8.5%	6.2%
Exit date	2010	2041	2017	2018	2018	2018	n/a ¹	n/a ¹	n/a ¹

¹ U.K. valuations assume properties held in perpetuity

The underlying value of our combined commercial office and retail portfolio represents a 7.2% “going in” capitalization rate based on the 2008 total operating cash flows, excluding gains, of \$1.7 billion. The valuations are most sensitive to changes in the discount rate. A 100-basis point change in the discount rate results in a \$1.4 billion change in our common equity value after reflecting the interests of minority shareholders.

Renewable Power Generation

We have assembled one of the largest privately owned hydroelectric power generating portfolios in the world. Our power generating operations are predominantly hydroelectric facilities located on river systems in the U.S., Canada and Brazil. As at December 31, 2008, we owned and managed 162 conventional hydroelectric generating stations with a combined generating capacity of approximately 3,129 megawatts. Power stations are located in Ontario, Quebec, British Columbia, New York, New England, Louisiana and Brazil. This geographic distribution provides diversification of water flows to minimize the overall impact of hydrology fluctuations. Our storage reservoirs contain sufficient water to produce approximately 22% of our total annual generation and provide partial protection against short-term changes in water supply. The reservoirs also enable us to optimize selling prices by generating and selling power during higher-priced peak periods. We also own and operate two natural gas-fired plants, a 600 megawatt pumped storage facility and a 189 megawatt wind energy project. Overall, our assets represent 4,133 megawatts of generating capacity.

AS AT DECEMBER 31	Capacity (MW)		# of Stations		Long-Term Average Generation (GWh)	
	2008	2007	2008	2007	2008	2007
Hydroelectric generation						
North America						
United States	1,303	1,284	99	98	6,072	5,927
Canada	1,314	1,308	32	32	4,971	4,931
Brazil	512	295	31	26	2,152	1,257
Total hydroelectric generation	3,129	2,887	162	156	13,195	12,115
Wind energy	189	189	1	1	534	534
Co-generation and pump storage	815	815	3	3	1,264	1,168
	4,133	3,891	166	160	14,993	13,817

The following table summarizes our invested capital and the net operating cash flow generated by our power generating operations during 2008 and 2007:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Hydroelectric generation	\$ 4,223	\$ 4,299	\$ 4,223	\$ 4,299	\$ 796	\$ 531	\$ 796	\$ 531
Wind, pump storage and cogeneration	479	602	479	602	90	80	90	80
Development	253	236	253	236	—	—	—	—
	4,955	5,137	4,955	5,137	886	611	886	611
Cash and financial assets	357	784	357	784			—	—
Working capital	1,161	881	335	2			(21)	(7)
Unsecured corporate power borrowings			(653)	(797)			(40)	(41)
Property-specific debt/interest expense			(3,587)	(3,488)			(273)	(248)
Co-investor interests			(192)	(213)			(86)	(54)
	\$ 6,473	\$ 6,802	\$ 1,215	\$ 1,425	\$ 886	\$ 611	\$ 466	\$ 261
Underlying value	\$ 12,051		\$ 6,639					

Total assets in this segment decreased \$0.3 billion to \$6.5 billion from \$6.8 billion during the year due to accounting depreciation and the impact of translating non-U.S. dollar denominated assets at lower currency exchange rates, offset by the acquisition and development of facilities in North America and Brazil. In aggregate, we invested \$24 million in development and \$372 million in acquisitions during the year.

During 2008, we commenced commercial operations at three new hydroelectric facilities in Brazil that have a combined capacity to generate 61 megawatts of electricity and we currently have three other projects under construction in the country, totalling 85 megawatts of installed capacity that are expected to commence commercial operations during 2009. The acquisitions completed during 2008 added 156 megawatts in Brazil and 18 megawatts in the United States.

Property-specific debt has an average interest rate of 7%, an average term of 12 years and is all investment grade quality. The corporate unsecured notes bear interest at an average rate of 5%, have an average term of eight years and are rated BBB by S&P, BBB (high) by DBRS and BBB by Fitch.

The following table highlights the variances in operating cash flow between 2008 and 2007:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Net Operating Cash Flow		
	2008	2007	Variance
Hydroelectric generation			
North America			
United States	\$ 397	\$ 292	\$ 105
Canada	271	171	100
Brazil	128	68	60
Total hydroelectric generation	796	531	265
Other generation			
Wind energy	32	33	(1)
Co-generation and pump storage	58	47	11
Total operating cash flow	886	611	275
Cash taxes and other expenses	(21)	(7)	(14)
Interest expenses	(313)	(289)	(24)
Non-controlling interests	(86)	(54)	(32)
Net operating cash flow	\$ 466	\$ 261	\$ 205

Total operating cash flows increased by \$275 million to \$886 million due to a 9% increase in realized prices and a 24% increase in generation. Net operating cash flow increased by \$205 million to \$466 million, as the increase in total cash flows was partially offset by increased financing costs, cash taxes and other expenses, and the interests of co-investors in the increased profitability.

Realized Prices and Operating Margins

The following table illustrates revenues and operating costs for our hydroelectric facilities:

FOR THE YEARS ENDED DECEMBER 31 (GIGAWATT HOURS AND \$ MILLIONS)	2008				2007			
	Actual Production	Realized Revenues	Operating Costs	Operating Cash Flows	Actual Production	Realized Revenues	Operating Costs	Operating Cash Flows
Canada	5,277	\$ 360	\$ 89	\$ 271	3,892	\$ 250	\$ 79	\$ 171
United States	6,681	551	154	397	5,673	420	128	292
Brazil	2,267	182	54	128	1,326	105	37	68
Total	14,225	\$ 1,093	\$ 297	\$ 796	10,891	\$ 775	\$ 244	\$ 531
Per MWh		\$ 77	\$ 21	\$ 56		\$ 71	\$ 22	\$ 49

Realized prices from our hydro portfolio increased by 9% to \$77 per megawatt hour compared to 2007 levels, due to recontracting power (including short-term financial contracts) at higher prices, higher volumes for capacity and other ancillary services and our ability to surface higher revenue by generating power during peak price periods. The higher water levels provided us with a greater amount of generation that had not been previously contracted, allowing us to benefit from the high energy price environment by selling the additional energy generated at the higher spot prices. Our ability to capture peak pricing and sell other energy products, such as capacity, also contributed to higher realized prices.

Operating costs declined slightly on a per unit basis. In Canada, higher generation levels reduced the per unit impact of fixed costs. Costs in Brazil benefited from a lower currency exchange rate over the year although this also reduced the associated revenues. Operating costs in the United States were relatively unchanged on a per unit basis.

Cash flows from our non-hydro facilities, as shown in the following table, increased due to higher realized prices, despite lower generation levels. The higher realized price is a result of our ability to participate in the forward reserve market using our pump storage facility, thereby receiving incremental cash payments in return for committing our generating capacity, in addition to the revenues from actual generation.

FOR THE YEARS ENDED DECEMBER 31 (GIGAWATT HOURS AND \$ MILLIONS)	2008				2007			
	Actual Production	Realized Revenues	Operating Costs	Operating Cash Flows	Actual Production	Realized Revenues	Operating Costs	Operating Cash Flows
Co-generation and pump storage	1,249	\$ 156	\$ 98	\$ 58	1,493	\$ 147	\$ 100	\$ 47
Wind energy	456	40	8	32	478	41	8	33
Total	1,705	\$ 196	\$ 106	\$ 90	1,971	\$ 188	\$ 108	\$ 80
Per MWh		\$ 115	\$ 62	\$ 53		\$ 95	\$ 55	\$ 40

Generation

The following table summarizes generation over the past two years:

FOR THE YEARS ENDED DECEMBER 31 (GIGAWATT HOURS)	Long-Term Average	Actual Production		Variance to	
		2008	2007	Long-Term Average	Actual 2007
Existing capacity	11,851	12,921	10,665	1,070	2,256
Acquisitions – during 2007 and 2008	1,344	1,304	226	(40)	1,078
Total hydroelectric operations	13,195	14,225	10,891	1,030	3,334
Wind energy	534	456	478	(78)	(22)
Co-generation and pump storage	1,264	1,249	1,493	(15)	(244)
Total generation	14,993	15,930	12,862	937	3,068

Total hydroelectric generation increased by 3,334 gigawatt hours or 31% over 2007 due to increased generation from our conventional hydroelectric facilities. Approximately two-thirds of the increase (2,256 additional gigawatt hours) came from existing hydroelectric capacity owned throughout 2008 and 2007 (i.e. “same store” basis) due to higher water flows while approximately one-third (1,078 gigawatt hours) came from recently acquired or developed facilities. Hydroelectric generation was 8% above expected long-term averages, whereas the 2007 results were 10% below long-term averages. Our wind facilities generated 456 gigawatt hours, which was lower than the long-term average. However availability has averaged 97% since its commissioning in

2006. With respect to 2009, our reservoirs are at normal levels for this time of year and, as a result, we believe that we are in a good position to be able to operate our facilities at long-term average levels during the year, assuming normal water conditions prevail.

Contract Profile

Consistent with our strategy to establish lower volatility revenue streams, the prices for approximately 75% of our projected generation for 2009 and 2010 are contracted pursuant to long-term bilateral power sales agreements or shorter-term financial contracts. The remaining generation is sold into wholesale electricity markets when certainty of generation is confirmed.

Our long-term sales contracts, which account for more than 50% of total generation, have an average term of 12 years. The majority of our counterparties are investment grade in nature, including a number of government agencies. The financial contracts typically have a term of less than two years and are with high credit-worthy counterparties.

The following table sets out the profile of our contracts over the next five years from our existing facilities, assuming long-term average hydrology:

	Years ended December 31				
	2009	2010	2011	2012	2013
Generation (GWh)					
Contracted					
Power sales agreements	7,566	7,534	7,065	6,296	6,061
Financial contracts	4,366	2,873	—	—	—
Uncontracted	2,954	4,373	7,721	8,482	8,717
	14,886	14,780	14,786	14,778	14,778
Contracted generation					
% of total	80%	70%	48%	43%	41%
Revenue (\$millions)	805	733	495	466	461
Price (\$/MWh)	67	70	70	74	76

The average selling price for contracted power increases to \$76 per megawatt hour from \$67 per megawatt hour over the next five years, reflecting contractual step-ups in long duration contracts with locked-in prices and the expiry of lower priced contracts during the period. The decrease in these prices from those reported in prior quarters reflects the impact of lower currency exchange rates on non-U.S. contracts which should also have a mitigating impact on operating expenses and borrowing costs.

Underlying Value

The underlying value of our power generation portfolio was determined to be \$6.6 billion as at December 31, 2008 in total after deducting borrowings and minority interests. The key metrics are set out in the following table:

	United States			Canada			Brazil		
	Minimum	Maximum	Average	Minimum	Maximum	Average	Minimum	Maximum	Average
Discount rate	9.0%	12.0%	10.5%	9.0%	12.0%	10.7%	13.0%	13.0%	13.0%
Terminal capitalization rate	11.0%	12.0%	11.1%	11.0%	12.0%	11.0%	14.0%	14.0%	14.0%
Exit date	2028	2028	2028	2014	2028	2027	2028	2028	2028

The total valuation of our hydroelectric facilities of \$12.1 billion represents a “going-in” capitalization rate of 7.6% based on 2008 cash flows adjusted to reflect long-term average hydrology. The valuations are impacted primarily by the discount rate and long-term power prices. A 100-basis point change in the discount rate and a 10% change in long-term power prices will each impact the value of our net invested capital by \$0.9 billion.

INFRASTRUCTURE

Our infrastructure activities are currently concentrated in the timber and electricity transmission sectors, although we expect that, over time, we will expand into new sectors that provide similar investment characteristics. Our operations are located in the United States, Canada, Chile and Brazil and are primarily owned through managed funds. The invested capital and net operating cash flows contributed by these operations are summarized in the following table:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Timberlands	\$ 3,557	\$ 3,675	\$ 439	\$ 1,025	\$ 169	\$ 158	\$ 61	\$ 40
Transmission	856	760	322	620	166	160	80	62
	\$ 4,413	\$ 4,435	\$ 761	\$ 1,645	\$ 335	\$ 318	\$ 141	\$ 102
Underlying value	\$ 5,059		\$ 974					

Timber

We manage 2.6 million acres of high quality private freehold timberlands with an aggregate underlying value of \$4.2 billion. These assets are held primarily through two private funds that currently hold operations located on the west coast of Canada and the U.S. Pacific Northwest. We also manage a listed specialty issuer that operates in Eastern North America and a \$280 million private timber fund focused on Brazil, which is largely uninvested at this time, and hold direct interests in timber assets in Brazil.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Timberlands								
Western North America	\$ 2,613	\$ 2,708			\$ 146	\$ 130		
Eastern North America	150	185			15	20		
Brazil	63	66			8	8		
	2,826	2,959	\$ 2,826	\$ 2,959	169	158	\$ 169	\$ 158
Working capital/other expenses	731	716	158	74			(5)	—
Property-specific debt/interest expense			(1,550)	(1,691)			(89)	(85)
Co-investor interests			(995)	(317)			(14)	(33)
	\$ 3,557	\$ 3,675	\$ 439	\$ 1,025	\$ 169	\$ 158	\$ 61	\$ 40
Underlying value	\$ 4,164		\$ 613					

Consolidated assets held within our timber operations and related borrowing levels were relatively unchanged during the year. Net invested capital declined with the transfer of 30% of our U.S. Pacific Northwest operations and three-quarters of our interest in our Western Canadian operations to 40%-owned Brookfield Infrastructure Partners L.P. ("Brookfield Infrastructure Partners") as well as the subsequent transfer of our remaining 70% interest in the U.S. Pacific Northwest operations to a global timber fund in which we hold a 37% direct and indirect interest. This resulted in a corresponding increase in third-party interests and the receipt by us of \$590 million in cash proceeds.

Total operating cash flow increased to \$169 million, reflecting a full year contribution from the U.S. Pacific Northwest operations, which were acquired in April 2007, as well as a \$24 million gain from the partial sale of these assets to our global timber fund. These factors were offset by lower prices due to the slowdown in the U.S. homebuilding industry, which resulted in lower demand and prices for premium species such as high quality Douglas fir. In response, we continue to exploit the flexibility inherent in timber management which allows us to defer harvesting until prices recover and also allows the trees to continue to grow. Our Western North American operations have also increased on exports to Asia, which provided higher margins.

Interest costs were in line with the prior year while co-investor interests in operating cash flows declined in line with the reduction in operating margins and net operating cash flows. During the year we raised \$1.0 billion of non-recourse debt secured by our U.S. Pacific Northwest operations which has an average term of 7 years and a 5.2% interest rate to replace shorter-term debt that was maturing later in the year. The overall duration of timber borrowings is 9 years, compared to 5 years at the end of 2007.

The following table summarizes the operating results from our timber operations:

	2008		2007	
	Sales (000's m ³)	Revenue (\$ millions)	Sales (000's m ³)	Revenue (\$ millions)
FOR THE YEARS ENDED DECEMBER 31				
Western North America				
Douglas fir	2,397	\$ 210	2,092	\$ 191
Whitewood	1,249	74	1,318	87
Other species	657	71	353	51
	4,303	355	3,763	329
Eastern North America and Brazil	2,535	82	1,920	89
	6,838	\$ 437	5,683	\$ 418

We sold 6.8 million cubic metres of timber during 2008, up 20% compared to 2007, reflecting a full year contribution from the U.S. Pacific Northwest timberlands, partially offset by lower volumes of Douglas fir and Whitewood due to the slowdown in the U.S. homebuilding industry. Sales volumes of other species increased as a result of better relative market conditions for pulp logs and cedar. Eastern North America and Brazil volume increased relative to 2007 with higher volumes in Brazil being partly offset by the lower volumes in Eastern North America.

Realized prices across our operations declined by approximately 13% while operating costs per unit were higher due to product mix and to a lesser extent higher fuel costs. The average realized price for Douglas fir decreased by 4% compared to the prior year. Declines in prices of products sold to the domestic market were offset by a higher percentage of high value appearance and export grade products sold to off-shore markets. The average selling price for Whitewood decreased by 10% over 2007 reflecting North American market conditions. The change in the average realized price for other species is mostly attributable to alternations in the mix of products included in that category.

Transmission

Our electricity transmission operations include the largest transmission system in Chile, a smaller transmission and distribution system in Northern Ontario and interests in transmission lines in Brazil which have been sold in a transaction which is expected to close in March 2009. Our direct and indirect interests in these operations, which are held through funds managed by us, are as follows: 17% in the Chilean operations; 40% and 100% in the Northern Ontario transmission and distribution operations, respectively; and 8% in the Brazilian operations.

Our transmission operations generate stable revenues that are largely governed by regulated frameworks and long-term contracts. Accordingly, we expect this segment to produce consistent revenue and margins that should increase with inflation and other factors such as operational improvements. We also expect to achieve continued growth in revenues and income by investing additional capital into our existing operations.

	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)								
Transmission facilities and investments								
Chile	\$ 324	\$ 330			\$ 37	\$ 114		
North America	158	193			37	31		
Brazil	207	205			91	15		
	689	728	\$ 689	\$ 728	165	160	\$ 165	\$ 160
Working capital/other expenses	167	32	116	6	1	—	(22)	(4)
Property-specific debt/interest expense			(237)	(114)	—	—	(13)	(65)
	856	760	568	620	166	160	130	91
Co-investor interests			(246)	—	—	—	(50)	(29)
	\$ 856	\$ 760	\$ 322	\$ 620	\$ 166	\$ 160	\$ 80	\$ 62
Underlying value	\$ 895		\$ 361					

Consolidated assets held within our transmission operations were relatively unchanged during the year. Net invested capital declined with the transfer of our Northern Ontario transmission operations, the majority of our interest in our Chilean operations, and our interests in the Brazilian transmission lines to 40%-owned Brookfield Infrastructure Partners. This resulted in a corresponding increase in co-investor interests.

Transmission operations contributed \$80 million of net operating cash flow, after deducting carrying charges and co-investor interests, compared with \$62 million during 2007. Total operating cash flows in each year were \$166 million and \$160 million, respectively.

The operating cash flows from our Chilean operations are recorded on an equity basis (i.e. our proportionate share of the net operating cash flows after deducting interest expense and co-investor interests) for all of 2008 whereas they were fully consolidated for the first six months of 2007. This resulted in an apparent decline in reported revenue, interest expenses and co-investor interests. The contribution from these operations on a comparable basis (i.e. equity accounted), however, was \$37 million in 2008 and \$28 million in 2007. The increase reflects non-recurring revenue as a result of a retroactive rate base increase, as well as the ongoing benefit of the rate base increase, inflation indexation and capital investments which is partially offset by a decrease in our ownership interest. After adjusting for non-recurring items, the operating margins at our Chilean transmission operations were 82% which is in line with historical levels.

We exercised our rights to sell our Brazilian investment pursuant to our original purchase agreement for an inflation adjusted return of 14.8%, giving rise to a revaluation gain of \$71 million in 2008. We expect to receive total proceeds of approximately \$274 million inclusive of hedge proceeds. To date, we have received \$68 million of proceeds, of which \$41 million was received subsequent to year end. We expect to receive the balance upon closing, which should occur during the first quarter of 2009, subject to receipt of regulatory and other approvals.

Underlying Value

The net asset value of our infrastructure operations was determined to be \$0.4 billion as at December 31, 2008 after deducting borrowings and minority interests.

The valuations of our timberlands are based on independent appraisals. Key assumptions include a weighted average discount and terminal capitalization rate of 6.5% at a terminal valuation date of 72 years on average. Timber prices were based on a combination of forward prices available in the market and the price forecasts of each appraisal firm.

The valuation of our transmission operations is based on the contractual sale price for our Brazilian interests, an independent valuation of our Chilean transmission business, and an internal valuation of our Northern Ontario operations based on the regulated rate base. In valuing our Chilean transmission business, key assumptions included a weighted average discount rate of 11.0%, a terminal capitalization rate of 8.6% and an average terminal valuation date of 2023.

DEVELOPMENT AND OTHER PROPERTIES

Development and other properties include our opportunity investment funds, residential operations, properties under development and held for development and construction activities.

	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)								
Opportunity investments	\$ 1,295	\$ 1,571	\$ 183	\$ 225	\$ 115	\$ 137	\$ 45	\$ 38
Residential	3,820	3,453	171	548	38	272	106	260
Under development	1,970	2,431	742	734	(25)	3	(27)	3
Held for development	2,260	1,801	1,693	1,355	—	—	—	—
Construction activities	1,299	1,517	545	602	81	—	81	—
	\$ 10,644	\$ 10,773	\$ 3,334	\$ 3,464	\$ 209	\$ 412	\$ 205	\$ 301
Underlying value	\$ 10,619		\$ 3,313					

Opportunity Investments

We manage niche real estate opportunity funds with \$435 million of committed capital (Brookfield's share – \$247 million).

Total property assets within the funds were approximately \$1.3 billion at year end, a decrease of \$0.3 billion from the end of 2007, due to asset sales. The portfolio of 99 properties is comprised predominantly of office properties in a number of cities across North America as well as smaller investments in industrial, student housing, multi-family and other property asset classes.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Properties	\$ 1,295	\$ 1,571	\$ 1,082	\$ 1,280	\$ 72	\$ 67	\$ 72	\$ 67
Disposition gains	—	—	—	—	43	70	23	28
Property-specific mortgages/interest expense	—	—	(773)	(934)	—	—	(42)	(54)
Co-investor interests	—	—	(126)	(121)	—	—	(8)	(3)
	\$ 1,295	\$ 1,571	\$ 183	\$ 225	\$ 115	\$ 137	\$ 45	\$ 38

Due to the focus on value enhancement and the relatively short hold period for properties, we expect that most of our returns will come from disposition gains, as opposed to net rental income. Our first fund is fully invested and is continuing to sell properties that have been successfully repositioned while we continue to invest the capital committed to our second fund.

Residential

We conduct residential property operations in Canada, Brazil, Australia and the United States, in which we hold the following interests: Canada – 51%; Brazil – 42%; Australia – 100%; and United States – 58%.

We benefited from the diversification of our residential operations as the impact of the slowdown in the U.S. was offset by profitable contributions from our Canadian and Brazilian operations.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Residential properties								
Canada	\$ 478	\$ 516	\$ 478	\$ 516	\$ 144	\$ 237		
Brazil	1,878	1,009	735	612	69	92		
Australia	486	544	486	98	(7)	—		
United States	978	1,384	821	1,224	(15)	46		
Impairment charge – U.S. operations					(153)	(103)		
	3,820	3,453	2,520	2,450	38	272	\$ 38	\$ 272
Subsidiary borrowings/interest expense ¹			(1,727)	(1,363)	—	—	(6)	(18)
Cash taxes			—	—	—	—	73	18
Co-investor interests			(622)	(539)	—	—	1	(12)
	\$ 3,820	\$ 3,453	\$ 171	\$ 548	\$ 38	\$ 272	\$ 106	\$ 260

¹ Portion of interest expensed through cost of sales

Total assets, which include property assets as well as housing inventory, cash and cash equivalents and other working capital balances, increased since 2007 reflecting expansion within our Brazil operations offset by lower levels of activities in the United States. Subsidiary borrowings consist primarily of construction financings which are repaid with the proceeds received from sales of building lots, single-family houses and condominiums, and are generally renewed on a rolling basis as new construction commences.

The net operating cash flows attributable to each of these business units are as follows:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007	Variance
Canada	\$ 144	\$ 237	\$ (93)
Brazil	31	44	(13)
– Dilution loss	(18)	—	(18)
Australia	(7)	—	(7)
United States	(44)	(21)	(23)
	106	260	(154)
Less: minority interests of Brookfield Properties in Canadian operations	(71)	(116)	45
	\$ 35	\$ 144	\$ (109)

Canada

We continue to benefit from our strong market position and low-cost land bank, particularly in Alberta where we hold a 23% market share in Calgary. We own approximately 15,538 acres (December 31, 2007 – 14,864 acres) of which approximately 901 acres (December 31, 2007 – 1,004 acres) were under active development at year end. The balance of 14,637 acres (December 31, 2007 – 13,860 acres) is included in “Held for Development” because of the length of time that will likely pass before they are actively developed.

The Canadian operations contributed \$144 million of net operating cash flow for the year, compared to a record \$237 million in 2007. We share approximately 50% of the cash flows (and the changes therein) with the minority shareholders of Brookfield Properties. The net contribution, reflecting these interests, was \$73 million in 2008 and \$121 million in 2007. The decrease in cash flows is due primarily to lower lot sales, which declined from 2,089 in 2007 to 1,399 in 2008 as well as the impact of the lower Canadian dollar. Operating margins decreased to 29% compared with the record high of 34% in 2007 and 31% margin in 2006.

Brazil

The strong financial position of our Brazilian operations, bolstered by an equity issue completed in late 2006, enabled us to expand these operations through the acquisition of MB Engenharia and a merger with Company S.A. These transactions increased our market position in São Paulo and Rio de Janeiro and also established a meaningful presence in the mid-west region of Brazil, including Brasília and Goiânia. The acquisitions also extended our product offerings into the important middle income segment, thereby providing a strong complement to our existing presence in the higher income segment.

Combined launches totalled more than R\$2.7 billion (\$1.4 billion) of sales value, and contracted sales during 2008 totalled R\$1.1 billion (\$600 million) representing gross sales revenues to be earned in current and future periods. The net operating cash flow from the business during 2008 was \$31 million compared with \$44 million during 2007. The decline is due to a lower level of construction, which reduced the amount of income recognized under the percentage-of-completion basis, however, the current construction schedule should enable this business to increase returns in 2009. We recorded a dilution loss of \$18 million for accounting purposes on the merger with Company S.A.

Australia

Our Australian operations generated \$4 million of operating cash flow during 2008, however these results were offset by an impairment charge of \$11 million. The carrying values of projects reflect our acquisition of this business in 2007 and therefore already include much of the expected development profits. Accordingly, margins are expected to be lower in the first few years of ownership.

United States

Our U.S. operations incurred \$15 million of cash outflows before interest, taxes and non-controlling interests during 2008 as demand for new homes slowed and margins narrowed, compared to \$46 million of cash inflows during 2007. The operations also recorded an impairment charge of \$153 million to reduce the carrying value of higher cost land and option positions. Our share of the net operating loss, after taking into consideration interest, taxes and non-controlling interests was \$44 million, compared with a net operating loss of \$21 million during 2007. The gross margin from housing sales was approximately 13% compared with 17% last year. We closed on 750 units during the year (2007 – 839 units) at an average selling price of \$562,000 (2007 – \$662,000). The backlog at the end of 2008 was 134 units compared to 155 units in 2007. In aggregate, we own or control 24,100 lots through direct ownership, options and joint ventures.

Under Development

Properties under development include both active development projects as well as properties that we are redeveloping to enhance their value. We are also developing a number of hydroelectric generating plants and retail properties which are included under “Renewable Power Generation” and “Commercial Properties – Retail”, respectively.

AS AT DECEMBER 31 (MILLIONS)	Total		Invested Capital	
	2008	2007	Net	2007
Commercial properties				
North America				
– Bay Adelaide office tower	\$ 510	\$ 416	\$ 510	\$ 416
– Other	324	465	324	465
Australasia				
– Macquarie Tower	230	195	230	195
– Others	496	660	496	660
United Kingdom	102	533	102	533
Brazil	308	162	308	162
Borrowings	—	—	(1,228)	(1,697)
	\$ 1,970	\$ 2,431	\$ 742	\$ 734

Current development initiatives in North America are focused on the construction of a 1.2 million square foot premier office property on the Bay Adelaide Centre site located in Toronto’s downtown financial district, representing a book value of \$510 million (2007 – \$416 million), and properties in Washington, D.C. Bay Adelaide Centre is 72% leased and scheduled for occupancy in the third quarter of 2009. We are also continuing the redevelopment of a 269,000 square foot property in Washington D.C.

We have 2.7 million square feet of commercial property space under development in Australia. Current developments include a 350,000 square foot office project fully leased to Macquarie Bank in Sydney, representing a book value of \$230 million (2007 – \$195 million), which is 86% complete, as well as three properties in Sydney, Melbourne, and Auckland, all of which are substantially preleased to tenants such as Sydney Water, Australia Post and Deloitte, with a collective book value of \$262 million. We have also commenced the construction of a 900,000 square foot premier office property in Perth, which is 82% leased to BHP Billiton, representing invested capital at year end of \$94 million (2007 – \$25 million).

In the United Kingdom, we own a proportionate share of approximately 7.9 million square feet of commercial space development density at Canary Wharf in London of which 1.3 million is currently under active development, and substantially pre-leased. Invested capital declined during the year with the completion of two projects that were then transferred to our active commercial portfolios.

Property-specific financing includes debt secured by Bay Adelaide Centre in North America as well as debt associated with developments in Australia and the United Kingdom.

Held for Development

We acquire land and long-term rights on land, seek entitlements to construct, and then either sell the development once it has been improved or build the project ourselves. We typically hold these developments directly, given that they do not generate current cash flow until the project is completed, at which time it can be transferred to an existing portfolio or sold outright. Accordingly, we do not typically record ongoing cash flow in respect of properties held for development and the associated development costs are capitalized until this event occurs, at which time any disposition gain or loss is recognized.

AS AT DECEMBER 31 (MILLIONS)	Invested Capital			
	Total		Net	
	2008	2007	2008	2007
Commercial office properties				
Ninth Avenue, New York	\$ 269	\$ 207	\$ 269	\$ 207
Other North America	122	105	122	105
Australia and U.K.	310	195	310	195
Residential lots				
North America	718	712	718	712
Brazil	352	92	352	92
Australia and U.K.	353	300	353	300
Rural development lands				
Brazil	136	190	136	190
Borrowings / working capital	—	—	(567)	(446)
	\$ 2,260	\$ 1,801	\$ 1,693	\$ 1,355

Commercial Office Properties

We own well-positioned land on Ninth Avenue between 31st Street and 33rd Street in New York City which is entitled for 5.4 million square feet of commercial office space. We will commence construction of this property once the necessary pre-leasing has occurred, similar to our strategy with other commercial developments.

Residential Lots

Residential development properties include land, both owned and optioned, which is in the process of being developed for sale as residential lots, but not expected to enter the homebuilding process for more than three years. We utilize options to control lots for future years in our higher land cost markets in order to reduce risk. To that end, we hold options on approximately 11,000 lots which are located predominantly in California and Virginia. We invested additional capital into development land in Alberta to maintain our market position and hold 14,637 acres. We also hold approximately 17,000 residential lots, homes and condominium units in our markets in Australia and New Zealand, which will provide the basis for continued growth. We increased our holdings in Brazil through a corporate acquisition and a merger during the year.

Rural Development Lands

We own approximately 372,000 acres of prime agricultural development land in the Brazilian States of São Paulo, Minas Gerais, Mato Grosso do Sul and Mato Grosso. These properties are being used for agricultural purposes, including the harvest of sugar cane for its use in the production of ethanol, which is used largely as a gasoline substitute. We also hold 33,200 acres of potentially higher and better use land adjacent to our Western North American timberlands, included within our Timberlands segment, which we intend to convert into residential and other purpose land over time. The decrease in carrying values during 2008 reflects lower currency exchange rates.

Construction Activities

The following table summarizes the operating results from our construction operations during the past two years:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Australia	\$ 1	\$ —			\$ 32	\$ —		
Middle East	49	20			48	—		
United Kingdom	74	104			1	—		
	124	124	\$ 124	\$ 124	81	—	\$ 81	\$ —
Working capital	1,175	1,393	421	478			—	—
	\$ 1,299	\$ 1,517	\$ 545	\$ 602	\$ 81	\$ —	\$ 81	\$ —

We conduct the majority of our construction activities in Australia and the Middle East with each region accounting for approximately one-half of the outstanding backlog. Our construction activities are focused on large scale construction of real estate and infrastructure assets.

The revenue work book totalled \$4.8 billion at the end of the year (December 31, 2007 – \$6.0 billion) and represented 3.5 years of scheduled activity. The decline reflects early completions and the impact of foreign exchange revaluation on Australian revenues.

The following table summarizes the work book at the end of the year:

AS AT DECEMBER 31 (MILLIONS)	2008	2007
Australia	\$ 2,254	\$ 3,143
Middle East	1,828	1,693
United Kingdom	727	1,177
	\$ 4,809	\$ 6,013

Underlying Value

The underlying value of our development assets after deducting borrowings and minority interests was \$3.3 billion as at December 31, 2008 equal to the net book value of our invested capital.

The valuation of residential development lots, which are considered inventory for these purposes, reflects the lower of the existing carrying value and their expected net realizable value. Net realization value is determined as the value at the anticipated time of sale less costs to complete, discounted at a rate of 12%-15%. Many of our land holdings, particularly those located in Alberta, were acquired many years ago. Accordingly, while we believe the fair value of these lands significantly exceeds existing carrying value, the carrying value for IFRS purposes will be the lower amount.

Values attributable to commercial office property developments reflect the estimated value at completion less the remaining capital expenditures, all discounted to the current period using discount rates of 7%-9%.

SPECIALTY FUNDS

We conduct bridge lending, restructuring and real estate finance activities. Although our primary focus throughout the broader organization is property, power and infrastructure assets, our mandates within our bridge lending and restructuring funds also include related industries which have tangible assets and visible cash flows, particularly where we have expertise as a result of previous investment experience. As at December 31, 2008, we managed eight specialty funds with total committed capital of \$4.4 billion.

Specialty investment funds generated net operating cash flow of \$126 million during 2008 compared with \$341 million in 2007. The 2007 results also included a \$231 million gain on our restructuring of Stelco Inc. ("Stelco").

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Restructuring	\$ 1,625	\$ 1,538	\$ 384	\$ 361	\$ 82	\$ 54	\$ 13	\$ 16
Real estate finance	2,045	685	298	263	128	26	26	24
Bridge lending	269	488	188	488	97	70	87	70
	3,939	2,711	870	1,112	307	150	126	110
Stelco disposition gain					—	231	—	231
	\$ 3,939	\$ 2,711	\$ 870	\$ 1,112	\$ 307	\$ 381	\$ 126	\$ 341
Underlying value	\$ 4,023		\$ 903					

Restructuring

We operate two restructuring funds. Our first fund, Tricap Restructuring Fund ("Tricap I") completed its investment period last year and we continue to manage and harvest the remaining invested capital of \$295 million. We also raised additional capital for Tricap Partners II ("Tricap II"), which now has C\$1 billion of committed capital.

Our two most significant investments in Tricap I are Western Forest Products Inc. (“Western Forest Products”) and Concert Industries Ltd. (“Concert Industries”). Western Forest Products experienced a difficult year due to the economic downturn and, in particular, weakness in the U.S. homebuilding sector. Concert Industries, a leading producer of air-laid woven fabric, continues to perform well. Investments in Tricap II include Ainsworth Lumber Company Ltd., which is a Canadian-based panelboard company, and several investments in the oil and gas sector.

The following table summarizes the results from our restructuring operations:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Assets/operating cash flow	\$ 1,625	\$ 1,538	\$ 1,625	\$ 1,538	\$ 82	\$ 54	\$ 82	\$ 54
Payables/other expenses			(341)	(433)			(1)	(4)
Borrowings/interest expense			(381)	(293)			(29)	(20)
Non-controlling interests			(519)	(451)			(39)	(14)
	\$ 1,625	\$ 1,538	\$ 384	\$ 361	\$ 82	\$ 54	\$ 13	\$ 16

Net operating cash flows were \$13 million in 2008 compared to \$16 million during 2007. In 2007, we completed the sale of Stelco, an integrated steel company, for a net disposition gain of \$231 million.

Similar to our opportunity property funds, we expect that the majority of our returns will come in the form of disposition gains as cash flows during the restructuring period are often below normalized levels.

Real Estate Finance

We operate three real estate finance funds with total committed capital of approximately \$1.9 billion, of which our share is approximately \$400 million. Our first fund, the \$600 million Brookfield Real Estate Finance Partners (BREF I) completed its investment period in 2007. We raised \$275 million of additional capital for our second fund (BREF II) during the year, bringing the total commitments to \$727 million. We had \$298 million of capital invested in these operations at year end (2007 – \$263 million).

The real estate finance group increased the level of invested assets by originating a number of high quality investment opportunities resulting in a greater contribution to operating cash flows. The portfolio continues to perform in line with expectations notwithstanding difficult credit markets, and credit losses have been negligible. These activities contributed \$26 million of net operating cash flow during 2008 compared to \$24 million in 2007.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flows			
	Total Assets		Net Assets		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Real estate finance investments	\$ 2,023	\$ 650	\$ 2,023	\$ 650	\$ 126	\$ 21	\$ 126	\$ 21
Less: borrowings			(1,130)	(345)			(58)	(2)
Less: co-investor interests			(617)	(77)			(44)	—
Real estate finance fund	2,023	650	276	228	126	21	24	19
Securities – directly held	21	21	21	21	1	2	1	2
Financial assets – Mortgage REIT	1	14	1	14	1	3	1	3
	\$ 2,045	\$ 685	\$ 298	\$ 263	\$ 128	\$ 26	\$ 26	\$ 24

Bridge Lending

We operate three bridge lending funds. Our first fund had commitments of C\$700 million at the end of the year which have been fully invested and the remaining loans will mature through 2011. We have raised C\$940 million in commitments and pledges for our two follow-on funds, consisting of a senior and junior fund, and including a C\$240 million commitment from Brookfield.

The net capital invested by us in bridge loans declined to \$188 million from \$488 million due to collections and our adoption of a more cautious approach to new loan commitments. Notwithstanding the difficult environment, we recorded net gains of \$48 million on convertible securities acquired through one of our financing mandates, which offset the reduction in interest income that arose from the lower level of invested assets during the year.

Our portfolio at year end was comprised of 11 loans, and our largest single exposure at that date was \$68 million. Our share of the portfolio at year end has an average term of 18 months excluding extension privileges and generates an average spread of 10% over the relevant base rate.

Underlying Value

The net asset value of our specialty fund operations was \$0.9 billion as at December 31, 2008 for the purposes of preparing our pro forma IFRS balance sheet. The values are based on publicly available share prices where available as well as comparable valuations and internal calculations.

INVESTMENTS

We own a number of investments which will be sold once value has been maximized, integrated into our core operations or used to seed new funds. Although not core to our broader strategy, we expect to continue to make new investments of this nature and dispose of more mature assets.

The net operating cash flow generated by our investments declined to \$115 million from \$127 million in 2007, prior to disposition gains. Disposition gains in 2007 arose on the sale of stock and commodity exchange seats and joint venture interests within our Brazil operations. The gain in 2008 arose from the disposition of 10 million common shares of Norbord Inc. ("Norbord") as settlement for exchangeable debentures issued in September 2004.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Location	Invested Capital				Operating Cash Flow			
		Total		Net		Total		Net	
		2008	2007	2008	2007	2008	2007	2008	2007
Forest products									
Norbord Inc.	North America/U.K.	\$ 1,024	\$ 180	\$ 179	\$ 19	\$ 22	\$ 21	\$ 14	\$ 11
Fraser Papers Inc.	North America	415	477	118	109	(40)	(15)	(33)	(22)
Privately held	North America	126	162	91	113	(26)	11	(26)	11
Infrastructure									
Coal lands	Alberta	70	85	70	85	6	6	6	6
Business services									
Insurance	Various	1,428	2,513	157	661	81	113	67	93
Privately held	Various	133	229	2	223	95	71	63	22
Publicly listed	Canada	60	52	38	26	40	5	24	4
Property									
Privately held	Brazil	75	153	47	100	—	6	—	2
		3,331	3,851	702	1,336	178	218	115	127
Gain on sale of exchange seats	Brazil	—	—	—	—	—	204	—	168
Norbord debenture exchange	North America/U.K.	—	—	—	—	65	—	65	—
Gain on sale of joint venture interests	Brazil	—	—	—	—	—	27	—	17
Net Investment		\$ 3,331	\$ 3,851	\$ 702	\$ 1,336	\$ 243	\$ 449	\$ 180	\$ 312
Underlying value		\$ 3,549		\$ 701					

Consolidated assets and net invested capital decreased to \$3.3 billion at the end of 2008 compared to \$3.9 billion at the end of 2007 due to the sale of a portion of the insurance business. The impact on consolidated assets was offset in part by the consolidation of Norbord following the increase in our net beneficial interest to 57% at year end.

Forest Products

We own a net beneficial interest in approximately 152 million shares of Norbord representing a 57% interest. Norbord completed a rights offering at the end of December 2008, through which we invested \$72 million. This increased our net beneficial interest from the 29% that we previously held. This also resulted in our commencing to account for this investment on a consolidated basis whereas we had previously treated it as an equity-accounted investment. We further increased our net beneficial interest in Norbord to 73% in early January through additional subscriptions to the same rights offering at an additional cost of \$120 million.

Our net beneficial interest and net invested capital are reduced by debentures issued by us that are exchangeable into 10 million Norbord shares and which are recorded at the market value of the Norbord shares. The reduction in the value of debenture liability resulted in a commensurate increase in our net carrying value. The 2008 operating cash flows from Norbord reflect only the dividends received on our common shares.

Fraser Papers Inc. ("Fraser Papers") and our privately held forest products operations faced a particularly difficult environment for their products during 2008, which resulted in operating losses.

Infrastructure

We own the coal rights under approximately 475,000 acres of freehold lands in central Alberta. These lands supply approximately 25% of Alberta's total power generation through the production of approximately 13 million tonnes of coal annually. Royalties from this production generate \$6 million of operating cash flow and provide a stable source of income as they are free of crown royalties. In addition, we own a 3.5% net profit interest in 75 million tonnes of proven reserves, and 34 million tonnes of potential reserves of high quality metallurgical coal in British Columbia.

Business Services

Our insurance operations are conducted through 80%-owned Imagine Insurance ("Imagine"), a specialty reinsurance business which operates internationally; Hermitage Insurance Company ("Hermitage"), a property and casualty insurer which operates principally in the Northeast United States; and Trisura Guarantee Insurance Company, a surety company based in Toronto. We manage the securities portfolios of these companies, which totalled \$1.0 billion and consist primarily of highly rated government and corporate bonds, through our public securities operations. We completed the sale of the United Kingdom reinsurance business within Imagine, thereby recovering capital of \$200 million, and negotiated the sale of Hermitage for proceeds of \$125 million, which is expected to close in the first quarter of 2009. We intend to recover the balance of the capital from the Imagine business over time through an orderly run-off of the business.

Underlying Value

The underlying values are determined by market values, actuarial valuations and internal calculations, and total \$3.5 billion compared to our carrying value of \$3.3 billion.

CASH AND FINANCIAL ASSETS

We hold a substantial amount of financial assets, cash and equivalents that are available to fund operating activities and investment initiatives.

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Invested Capital				Operating Cash Flow			
	Total		Net		Total		Net	
	2008	2007	2008	2007	2008	2007	2008	2007
Financial assets								
Government bonds	\$ 177	\$ 420	\$ 177	\$ 420				
Corporate bonds	123	286	123	286				
Fixed income	10	22	10	22				
High-yield bonds	88	112	88	112				
Preferred shares	25	40	25	40				
Common shares	230	51	230	51				
Loans receivable	317	101	317	101				
Total financial assets	970	1,032	970	1,032	\$ 519	\$ 709	\$ 519	\$ 709
Cash and cash equivalents	290	360	290	360			—	—
Deposits and other liabilities	—	—	(187)	(500)			(32)	(16)
Net investment	\$ 1,260	\$ 1,392	\$ 1,073	\$ 892	\$ 519	\$ 709	\$ 487	\$ 693
Underlying value	\$ 1,260		\$ 1,073					

Net cash and financial asset balances increased to \$1.1 billion during 2008 from \$0.9 billion at the end of 2007 due to the sale of government and corporate bonds. We have selectively established a number of common share positions in undervalued companies. In addition to the carrying values of financial assets, we hold common equity positions with a notional value of \$nil

(2007 – \$70 million) through total return swaps and hold protection against widening credit spreads through credit default swaps with a total notional value of \$2.5 billion (2007 – \$2.4 billion). The credit default swaps have limited downside and the market value of the instruments reflected in our financial statements at December 31, 2008 was \$30 million (2007 – \$85 million).

Net invested capital includes liabilities such as broker deposits and a small number of borrowed securities that have been sold short.

Operating cash flow in 2008 included a substantial amount of unrealized gains of which \$134 million (2007 – \$129 million) were recognized in respect of credit default swaps that protected us against widening credit spreads. We also realized gains of \$119 million in respect of foreign currency positions. Operating cash flow in 2007 also included gains of \$378 million from the sales of our holdings of debentures exchangeable into common shares of a major natural resources company.

ASSET MANAGEMENT ACTIVITIES

The following table summarizes asset management income for the past two years on a “total” basis, which includes income in respect of our own capital invested in funds, as well as the income earned solely from third-party clients. The portion of the income that is earned in respect of our own capital is eliminated in determining our financial results in accordance with GAAP. On the other hand, our financial results reflect 100% of the operating costs that we incur in managing these funds. Accordingly, we present both “total” income, which includes the income earned in respect of the capital we have invested in these funds, as well as “third-party” income, which is the income earned from our clients. We believe the operating margins are more accurate if they are based on 100% of both the expenses and the associated income.

	<i>Total</i> ¹		<i>Third Party</i>	
	2008	2007	2008	2007
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>				
Asset management				
Base management fees	\$ 178	\$ 137	\$ 134	\$ 104
Performance returns	10	12	6	8
Transaction fees	18	116	15	103
Property services	301	184	277	166
Investment banking	18	34	17	34
	525	483	\$ 449	\$ 415
Direct operating costs	(392)	(264)		
	\$ 133	\$ 219		

¹ Includes fees on Brookfield invested capital

Asset Management Income

Asset management income is dependent on the amount of capital managed by us on behalf of our clients (base management fees) and our investment performance (performance returns). Base management fees typically reflect a fixed percentage of assets or capital, including committed but uninvested capital and therefore vary based on the level of such assets or capital. Performance returns include contractual arrangements whereby we are entitled to a variable amount based on the relationship between actual investment returns and a predetermined benchmark, as well as carried interests whereby we participate in investment returns through an ownership interest in the assets being managed.

Base Management Fees

Base management fees include \$134 million (2007 – \$104 million) earned from third-party clients and \$44 million (2007 – \$33 million) from the capital that we have invested in existing funds. The increase was due to new funds launched during the past two years and an increase in capital committed to existing mandates, offset in part by the return of capital from more mature funds as investments are realized as well as the decline in value of fixed income and equity portfolios under management. As at December 31, 2008, annualized base management fees on existing funds and assets under management totalled \$170 million (2007 – \$160 million), of which \$130 million (2007 – \$120 million) relates to client capital. Annualized base management fees are an important measure of the expected contribution from these activities to our overall results and represent a stable source of cash flow that we believe adds considerable value to our business.

The following table presents the base management fees earned in respect of each of our operating platforms together with the associated capital commitments:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Base Management Fees				Capital Commitments			
	Total		Third Party		Total		Third Party	
	2008	2007	2008	2007	2008	2007	2008	2007
Commercial properties	\$ 41	\$ 30	\$ 27	\$ 16	\$ 4,591	\$ 4,540	\$ 2,869	\$ 2,898
Infrastructure	31	14	21	11	3,818	1,801	2,736	1,192
Development properties	7	3	4	2	818	817	388	359
Specialty funds	41	44	26	31	4,411	5,269	3,118	3,488
Other	6	6	6	6	84	84	63	59
	126	97	84	66	13,722	12,511	9,174	7,996
Public securities	52	40	50	38	18,040	26,237	18,040	26,237
	\$ 178	\$ 137	\$ 134	\$ 104	\$ 31,762	\$ 38,748	\$ 27,214	\$ 34,233

Base management fees within our commercial property sector are earned in respect of two North American core office funds, our Brazil retail property fund, and a number of smaller Australian and European property funds. Fees increased during the year due primarily to the addition of the Australian and European funds.

The fees earned in respect of our infrastructure operations increased due to the launch of Brookfield Infrastructure Partners, an infrastructure investment partnership listed on the New York Stock Exchange at the beginning of the year, as well as the contribution from a global timber fund that commenced operations in October.

Specialty funds include the fees from our restructuring, real estate finance and bridge lending funds. The decrease during the year is due to the impact of the higher U.S. dollar on Canadian dollar fee streams and capital commitments, notwithstanding the launch of new funds in each of these areas and additional closings on third-party capital.

In our public securities group, we manage \$18 billion of fixed income and equity securities on an advisory basis for a large number of institutional and individual investors. These activities produced third-party revenues of \$50 million, which consist largely of base management fees. Management fees increased over 2007 levels due to a higher level of average assets under management following the acquisition of a real estate and equities securities manager in late 2007. Average fees earned as a percentage of assets under management also increased with the shift of our activities from traditional fixed income to equities and more value-added services such as distress portfolio management.

Performance Returns

The level of performance returns recorded in our results continues to be modest because they tend to materialize later in the life cycle of a fund and because we have elected to follow accounting guidelines that typically defer recognition in our financial statements. The following table includes performance returns from third parties on established funds that we believe have accumulated, but are not included in our reported results.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007
Accumulated returns, beginning of year	\$ 138	\$ 54
Net accumulation/(reduction) during the year	(73)	84
Total accumulated performance returns	\$ 65	\$ 138

We estimate that approximately \$9 million of direct expenses will arise on the realization of the returns that have accumulated to date. The average period of time over which these accumulated returns may be realized is six years, based on the terms of the relevant contracts. We expect that the ultimate receipt of these amounts will not result in any meaningful cash taxes.

Other Fees and Services Income

Transaction Fees

Transaction fees in 2007 include a fee of \$71 million earned in connection with our efforts to establish a North American retail property platform and an associated capital commitment. Transaction fees also include investment fees earned in respect of financing activities and include commitment fees, work fees and exit fees.

Property Services Income

Property services fees include property and facilities management, leasing and project management and a range of real estate services. The increase reflects a higher level of activity within our facilities management operations and the expansion of our operating base into Australia.

	Total		Third Party	
	2008	2007	2008	2007
FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)				
Property services revenues	\$ 301	\$ 184	\$ 277	\$ 166
Direct operating costs	(234)	(153)	(234)	(153)
	\$ 67	\$ 31	\$ 43	\$ 13

Investment Banking Fees

Our investment banking services are provided by teams located in Canada and Brazil and contributed \$17 million of fees during 2008. The group advised on transactions totalling \$9.3 billion in value during the year, and secured a number of prominent mandates. The 2007 revenues reflect the higher level of activity reflective of the capital markets at that time.

Assets Under Management

The following table summarizes total assets under management and net invested capital at the end of the past two years:

	Total Assets Under Management		Brookfield's Net Invested Capital		Third-Party Commitments	
	2008	2007	2008	2007	2008	2007
AS AT DECEMBER 31 (MILLIONS)						
Unlisted funds and specialty issuers						
Commercial properties	\$ 11,960	\$ 13,519	\$ 1,290	\$ 1,410	\$ 2,869	\$ 2,898
Infrastructure	6,201	3,766	696	609	2,736	1,192
Development properties	2,273	2,955	366	475	388	359
Specialty funds	4,817	7,362	870	1,126	3,118	3,488
Other	140	125	21	25	63	59
	25,391	27,727	3,243	3,645	9,174	7,996
Public securities mandates	18,161	26,237	20	21	18,040	26,237
Total fee bearing assets/capital	43,552	53,964	3,263	3,666	27,214	34,233
Directly held						
Operating assets	31,525	36,496	8,215	9,939		
Other assets	3,620	3,880	3,620	3,880		
	\$ 78,697	\$ 94,340	\$ 15,098	\$ 17,485	\$ 27,214	\$ 34,233

Total assets under management decreased by \$15.6 billion during the year. Approximately 50% of the decline occurred within our public securities operations and 33% of the decrease occurred within our directly held assets, which reflects the impact of the higher U.S. dollar on assets in international regions as well as the transfer of timber and transmission assets into new unlisted funds and specialty issuers during the year. The balance of the decline occurred within our unlisted funds and specialty issuers.

Unlisted Funds and Specialty Issuers

This segment includes the unlisted funds and specialty listed issuers through which we own and manage a number of property, power, infrastructure and specialized investment strategies on behalf of our clients and ourselves. The funds are listed in more detail on page 76 and elsewhere in this MD&A.

Third-party capital commitments to these funds increased by \$1.2 billion during the year, reflecting commitments to the establishment of Brookfield Infrastructure Partners, a global timber fund and a Brazil timber fund, as well as additional commitments to our restructuring and real estate finance funds. These activities more than offset the impact of the higher U.S. dollar on international funds and the return of capital to investors from more mature funds. The decline in total assets under management also reflects the currency revaluations as well as a lower level of bridge loans and real estate securities, offset by the higher level of timber and transmission assets under management.

Public Securities

We specialize in fixed income and equity securities with a particular focus on distress real estate and infrastructure. Our fixed income mandates are managed primarily by New York-based Brookfield Hyperion Asset Management Inc. Brookfield Redding LLC, based in Chicago, which has a well-established record as a leading real estate equity securities manager with a wide variety of clients throughout North America and Australasia. Brookfield Soundvest Capital Management Ltd., based in Ottawa, Canada, manages fixed income and equity securities on behalf of a number of Canadian institutional investors.

The following table summarizes assets under management within these operations. We typically do not invest our own capital in these strategies as the assets under management tend to be securities as opposed to physical assets.

AS AT DECEMBER 31 (MILLIONS)	Total Assets Under Management		Third-Party Commitments	
	2008	2007	2008	2007
Real estate and fixed income securities				
Fixed income	\$ 15,199	\$ 20,210	\$ 15,078	\$ 20,210
Equity	2,962	6,027	2,962	6,027
	\$ 18,161	\$ 26,237	\$ 18,040	\$ 26,237

Co-investor commitments declined by \$8 billion during 2008 primarily due to a reduction in market prices of securities under management. We secured \$3.4 billion of new advisory mandates during the year offset by \$4.2 billion of redemptions.

Directly Held

Operating assets and the associated net invested capital declined by \$6.0 billion and \$2.1 billion, respectively, reflecting the transfer of infrastructure assets into Brookfield Infrastructure Partners and the global timber fund, as well as currency revaluations. We hope to transfer more of the remaining operations into funds over time.

FINANCING AND OPERATING COSTS

Interest

Interest costs include interest expense on corporate borrowings, certain subsidiary borrowings, property-specific borrowings and capital securities as set out in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Total			Net		
	2008	2007	Variance	2008	2007	Variance
Corporate borrowings	\$ 163	\$ 146	\$ 17	\$ 163	\$ 146	\$ 17
Subsidiary borrowings ²	384	324	60	77 ¹	66 ¹	11
Property-specific borrowings	1,349	1,226	123	—	—	—
Capital securities	88	90	(2)	88	90	(2)
	\$ 1,984	\$ 1,786	\$ 198	\$ 328	\$ 302	\$ 26

¹ Relates to financial obligations that are guaranteed by the Corporation or issued by direct corporate subsidiaries

Interest on corporate borrowings and net interest expense both increased during the year due to a higher level of average balances. The increase in interest on subsidiary and property-specific borrowings is related to financings incurred and assumed with the acquisition of property assets in Australia, Europe, and Brazil as well as renewable power facilities in North America and Brazil.

Average borrowing costs during the past two years are as follows:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008			2007		
	Average Outstanding	Interest Expense	Average Rate	Average Outstanding	Interest Expense	Average Rate
Corporate borrowings	\$ 2,301	\$ 163	7%	\$ 1,885	\$ 146	8%
Subsidiary borrowings	6,894	384	6%	4,905	324	7%
Property-specific borrowings	22,542	1,349	6%	18,281	1,226	7%
Capital securities	1,565	88	6%	1,560	90	6%
Preferred equity	870	44	5%	798	44	6%
	\$ 34,172	\$ 2,028	6%	\$ 27,429	\$ 1,830	7%

The average rate declined from 7% to 6% due to lower rates on floating rate debt.

Operating

Operating costs relate to our asset management and corporate activities.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Total			Net		
	2008	2007	Variance	2008	2007	Variance
Asset management						
Asset management activities	\$ 158	\$ 111	\$ 47	\$ 152	\$ 111	\$ 41
Property services	234	153	81	234	153	81
	392	264	128	386	264	122
Corporate and other costs	248	200	48	220	180	40
	\$ 640	\$ 464	\$ 176	\$ 606	\$ 444	\$ 162

Operating costs include those of Brookfield Properties, and reflect the costs of our asset management activities as well as costs which are not directly attributable to specific business units. Asset management costs increased from \$111 million in 2007 to \$152 million in 2008 on a net basis, reflecting the establishment of new funds and the continued increase in invested assets. Property services expenses in 2008 reflect the addition of Australian operations to this business. The increase in corporate and other costs from \$180 million to \$220 million reflects the continued growth of our business including expansion into new geographic areas such as Australia and a number of major corporate initiatives.

We have continued to expand our resources as we grow our business which has resulted in higher operating costs, and we have also incurred a number of transaction and other costs related to growth initiatives. We believe these investments will enable us to expand our business without further commensurate increases in costs, thereby resulting in expanded margins.

Interests of Other Investors in Consolidated Operations

Co-investor interests relate primarily to the 49% minority equity interest held by others in our North American property subsidiary, Brookfield Properties.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Cash Flow					
	Total			Net		
	2008	2007	Variance	2008	2007	Variance
Commercial properties						
Brookfield Properties	\$ 419	\$ 368	\$ 51	\$ 419	\$ 368	\$ 51
Property funds and other	99	71	28	31	—	31
Renewable power generation	82	47	35	—	—	—
Infrastructure	64	38	26	—	—	—
Development and other properties	28	70	(42)	—	—	—
Specialty funds	89	13	76	—	—	—
Investments	10	29	(19)	—	—	—
	\$ 791	\$ 636	\$ 155	\$ 450	\$ 368	\$ 82

The increase in operating cash flows reflects increased returns and gains within our North American office property portfolios offset by lower operating cash flows from our Canadian residential property business, both of which are owned through Brookfield Properties. The decrease in cash flows related to development properties is due to lower returns in our U.S. homebuilding operations and the increase in cash flows related to specialty funds is due in part to the consolidation of one of our real estate finance funds.

NET INCOME

Net income was \$649 million in 2008, compared to \$787 million in 2007. The higher results in 2007 reflected a larger amount of disposition gains. Net income in 2008 also reflects depreciation and amortization with respect to assets purchased since the beginning of 2007 offset by accounting income arising from changes in future tax balances.

The following table reconciles net income and operating cash flow on a total basis and also by presenting the reconciling items on a basis that is net of non-controlling and minority interests:

	<i>Total</i>		<i>Net ¹</i>		
	<i>2008</i>	<i>2007</i>	<i>2008</i>	<i>2007</i>	<i>Variance</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>					
Operating cash flow and gains	\$ 1,423	\$ 1,907			
Less: dividends from equity accounted investments	(22)	(21)			
exchangeable debenture gain	—	(331)			
	\$ 1,401	\$ 1,555	\$ 1,401	\$ 1,555	\$ (154)
Non-cash items					
Depreciation and amortization	(1,330)	(1,034)	(773)	(553)	(220)
Equity accounted results	(46)	(72)	(46)	(72)	26
Revaluation and other items	(267)	(112)	(207)	(95)	(112)
Future income taxes	461	(88)	274	(48)	322
Non-controlling interests	430	538	—	—	—
Net income	\$ 649	\$ 787	\$ 649	\$ 787	\$ (138)

¹ Net of non-controlling and minority interests

Depreciation and Amortization

Depreciation and amortization prior to non-controlling interests increased due to the acquisition of additional assets in a number of segments during 2007 and 2008. Depreciation and amortization for each principal operating segment is summarized in the following table:

	<i>Total</i>		<i>Net ¹</i>		
	<i>2008</i>	<i>2007</i>	<i>2008</i>	<i>2007</i>	<i>Variance</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>					
Commercial properties	\$ 765	\$ 572	\$ 362	\$ 212	\$ 150
Power generation	191	164	168	141	27
Infrastructure	137	138	94	102	(8)
Development and other properties	94	65	55	33	22
Specialty funds and investments	137	89	88	59	29
Other	6	6	6	6	—
	\$ 1,330	\$ 1,034	\$ 773	\$ 553	\$ 220

¹ Net of non-controlling and minority interests

The Australian property operations contributed \$140 million of depreciation and amortization towards the increase in total and net depreciation and amortization, of \$296 million and \$220 million, respectively.

Equity Accounted Results

We recorded net equity accounted losses of \$46 million during the year from our investment in Norbord. Norbord faced a weak price environment for its principal products due to the weakness in the U.S. homebuilding sector, in addition to higher input costs. We increased our interest in Norbord to 60% at year end and commenced accounting for this business on a consolidated basis at that time. We also increased our interest in Fraser Papers to 56% during the third quarter of 2007 and began to consolidate our interest at that time, and sold our interest in Stelco during the fourth quarter of 2007 for a gain of \$231 million.

The following table summarizes the contribution from our equity accounted investments for the past two years:

	<i>2008</i>	<i>2007</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>		
Norbord	\$ (46)	\$ (17)
Fraser Papers	—	(23)
Stelco	—	(32)
	\$ (46)	\$ (72)

Revaluation and Other Items

Revaluation and other items are comprised primarily of revaluation items which are non-cash accounting adjustments that we are required to record under GAAP to reflect changes in the value of certain contractual arrangements.

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Total		Net ¹		
	2008	2007	2008	2007	Variance
Norbord exchangeable debentures	\$ 65	\$ (9)	\$ 65	\$ (9)	\$ 74
Interest rate contracts	(252)	(64)	(244)	(64)	(180)
Power contracts	94	(63)	70	(48)	118
Commercial office revaluation	(147)	—	(73)	—	(73)
Other	(27)	24	(25)	26	(51)
	\$ (267)	\$ (112)	\$ (207)	\$ (95)	\$ (112)

¹ Net of non-controlling and minority interests

We recorded a \$65 million accounting gain from the decline in value of debentures issued by us that are exchangeable into Norbord common shares, and are valued based on the Norbord share price. We hold an equivalent number of shares into which the debentures are exchangeable, but are not permitted under GAAP to mark the hedged investment to market.

We hold interest rate contracts to provide an economic hedge against the impact of possible higher interest rates on the value of our long duration interest sensitive physical assets. The U.S. 10-year treasury rate moved from 4.02% to 2.21% during 2008, which led to a \$252 million decline in the net value of these contracts of which our share was \$244 million. Accounting rules require that we revalue these contracts each period even if the corresponding assets are not revalued.

In our power operations, we enter into long-term contracts to provide generation capacity, and are required to record changes in the market value of these contracts through net income whereas we are not permitted to record the corresponding increase in the value of the capacity and generation that we have pre-sold.

We adjusted the carrying value of commercial office properties located in Minneapolis based on our intention to restructure the ownership of these properties. This led to a non-cash provision of \$147 million, of which 49% is shared with the other owners of our North American office property business.

Future Income Taxes

Future income taxes in 2008 reflected a gain of \$479 million (our share – \$238 million) arising from the conversion of the entity owning a number of our U.S. office properties to an internal REIT, thereby lowering the applicable effective tax rate on future taxable income from these properties. Previously the taxable income from these properties had been offset by tax depreciation and other tax shelter carried forward from prior years. The tax provision also reflects the benefits from increases in tax loss pools, principally in Canada, which increase the amount of taxable income that we will be able to offset in future years.

Realization and Disposition Gains

Realization gains represent amounts recorded for accounting purposes that represent the appreciation in value that we expect to achieve in many of our long-life assets and which along with current cash flows is included in assessing the expected total return on our initial investment. This portion of the total return may not be recognized for many years, if ever, and a realization event usually takes the form of gains on a direct or indirect disposition of the assets, including the transfer of assets to funds. This appreciation in value represents an important component of our long-term investment returns, but is only recognized in our results at irregular points in time.

We recognize disposition gains on investments held within our operating platforms that are not necessarily held for the long-term, such as investments in our restructuring operations.

The following table summarizes major realization and disposition items included in our operating results:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating	Cash Flow from Operations		Net Income	
	Platform	2008	2007	2008	2007
Realization gains/(losses), net of taxes and minority interest					
Longview sale	Infrastructure	\$ 24	\$ —	\$ 15	\$ —
Brazil Residential dilution loss	Development	(18)	—	(18)	—
Core office properties – disposition	Real Estate	80	—	48	—
Private equity – other operations	Private Equity	58	—	58	—
Brazil exchange seats sale	Private Equity	—	168	—	168
Core office properties – debt breakage	Real Estate	—	(14)	—	(8)
Banco Brascan joint venture gain	Private Equity	—	17	—	17
		144	171	103	177
Disposition gains/(losses), net of taxes and minority interest					
Norbord exchangeable debenture	Private Equity	65	—	21	—
Office properties – disposition	Real Estate	—	54	—	32
Sale of Stelco	Specialty Funds	—	231	—	229
Disposition gains included in opening retained earnings	Cash and Financial Assets	—	331	—	—
		65	616	21	261
Total		\$ 209	\$ 787	\$ 124	\$ 438

OUTLOOK

The consequences of the current downturn in the economy, including a rise in unemployment, a drop in consumer and business confidence and spending, and ongoing disruption and uncertainty within the capital markets are having an adverse effect on many industries as a whole. While we are not immune to these factors, we attempt to organize our operations in a manner that provides an important measure of stability, consistent with our long-term business strategy. In particular, we believe that our focus on owning high quality assets, backing revenue streams with long-term contractual arrangements, match funding long life assets with long-term financings and maintaining a high level of liquidity will benefit us during these difficult times.

Accordingly, while these events may constrain our ability to increase operating cash flows in the near term, we remain confident in our ability to achieve our long-term objectives in that regard. Furthermore, we believe we will have the opportunity to make investments during this period at very favourable values that will create attractive shareholder value in the future.

Our renewable power operations experienced higher water levels during 2008 which resulted in generation levels that were 8% above long-term averages. We believe we are well positioned to achieve our targets of long-term average generation in 2009 based on current storage levels if normal hydrology conditions prevail. The forecast for natural gas and electricity prices during 2009 is lower than the spot prices realized by us in 2008, however, we have contracted pricing for approximately 75% of our generation over the next two years at favourable prices, which significantly mitigates the impact of lower spot electricity prices.

In our office property sector, leasing demand in most of our markets has tempered and we are beginning to see increasing direct and sublease availabilities and associated downward pressure on rents and economic fundamentals. Our occupancy levels, however, are at 97% across our portfolio and only 3% of the space within our managed portfolio is scheduled to come off lease in 2009 of which a large portion is customarily renewed in the normal course. The high quality of our properties relative to others in our markets should enable us to attract new tenants if we are unsuccessful in extending leases with the existing tenants. Furthermore, we believe our in-place rents continue to be below market. In North America, the average expiring rates in 2009 are \$19 per square foot compared with an estimated average market rate of \$32 per square foot, representing a substantial discount. A general lack of development, especially in central business districts, has also created stability from a supply perspective. Nevertheless, a prolonged economic downturn could lead to tenant bankruptcies and lower market rents which could reduce our cash flows. Our strong tenant lease profile, low vacancies and rental rates that in most properties are substantially below current market rates give us a high level of confidence that we can achieve our operating targets in 2009.

Within our infrastructure operations, we expect our transmission businesses to provide operating returns consistent with those recorded in 2008. We expect our timber operations to continue to experience reduced demand and pricing due to weakness in the U.S. homebuilding sector, which has caused us to reduce harvest levels in order to preserve value and increase exports to Asia.

Residential markets remain difficult in our core markets. The current supply/demand imbalance in North American markets has reduced operating margins and must be worked through before we experience margin improvements and volume growth. Most of the land holdings within our Canadian land operations were purchased in the mid-1990s or earlier and as a result have an embedded cost advantage today. This has led to favourable margins in this region. We expanded our Brazilian operations during 2008 which we expect will lead to an increased contribution from these markets during 2009.

We continue to expand our specialty funds operations by committing additional resources and launching new funds. We will focus on maintaining a high level of invested capital by deploying the capital from new funds, which should lead to continued growth. We expect that the current difficulties in credit markets will lead to a greater number of opportunities for our restructuring operations, and more attractive pricing for our real estate finance group, although the same conditions will likely reduce opportunities to monetize investments and the opportunity to recognize disposition gains.

Within our asset management activities, our goal is to expand our distribution capabilities, our client base and the amount of capital committed to us, which should, over time, increase the capital available to invest and lead to growth in asset management income. The current environment has made it more challenging to raise additional capital commitments and earn performance income, however we expect to record a stable contribution from base management fees.

The increase in the value of the U.S. dollar against various currencies is likely to reduce the contribution from our operations that are denominated in these other currencies, notably the Canadian dollar, the Brazilian real and the Australian dollar. The recent reductions in interest rates in most economies has a beneficial impact on our results, although this is limited because most of our financings are fixed rate in nature. Similarly, the long-term nature of our borrowing base and the relatively low proportion of annual debt maturities lessens the impact of higher credit spreads on new financings.

The investment market has become less competitive and acquisition prices have declined due in large part to reduced availability of capital for many owners and investors. The access to liquidity from our own balance sheet as well as from our clients, financial partners and the capital markets has provided us with available funds to invest in our own operations and in new opportunities. We believe the breadth of our operating platform and our disciplined approach should enable us to invest this capital on a favourable basis.

We have endeavoured to extend debt maturities on a proactive basis and reduce near-term financing requirements. Although we expect to renew or replace most of our existing financings at equivalent levels, we may reduce leverage in certain areas of our business. While we expect that any deleveraging will likely have a limited impact on our short term operating results it would reduce the capital available for investment. We maintain a high level of liquidity as further discussed in Part 3 of this MD&A, and regularly replenish our liquidity through operating cash flow and asset monetizations.

There are many factors that could impact our performance in 2009, both positively and negatively. We describe the material aspects of our business environment and risks in Part 5 of this MD&A.

Summary

In the short term, we recognize that the current economic environment will likely result in continued downward pressure on operating margins and provide fewer opportunities to increase operating returns. We believe, however, that our approach to business, which includes backing revenue streams with contractual obligations and the use of long-term fixed rate financings, among other strategies, is an important mitigating factor and should provide considerable stability in our cash flows from year to year.

We also believe that there will be a number of opportunities over the next two years to invest capital in our existing operations as well as in new assets and businesses on values that will generate increased cash flow per share and shareholder values over the longer term.

As a result, we believe that our businesses are well positioned to not only withstand the difficult short term environment but to invest and build for the future. This provides us with confidence that we will meet our long-term performance objectives with respect to cash flow growth and value creation, and continue to build Brookfield as a world-class asset manager.

PART 3 – CAPITALIZATION AND LIQUIDITY

The strength of our capital structure and the liquidity that we maintain enable us to achieve a low cost of capital for our shareholders and at the same time provide us with the flexibility to react quickly to potential investment opportunities and adverse changes in economic circumstances, such as we have witnessed over the past 18 months.

The following are the key elements of our capital strategy:

- Match fund our long-life assets with long-duration mortgage financings with a diversified maturity schedule;
- Provide recourse only to the specific assets being financed, with limited cross collateralization or parental guarantees;
- Limit borrowings to investment grade levels based on anticipated performance throughout a business cycle;
- Structure our affairs to facilitate access to capital and liquidity at multiple levels of the organization; and
- Maintain access to a broad range of financing markets.

As a result of the foregoing, most of our borrowings are in the form of long-term property-specific financings such as mortgages or project financings secured only by the specific assets. The diversification of our maturity schedule means that financing requirements in any given year are manageable. Limiting recourse to specific assets or business units ensures that weak performance by one asset or business unit does not compromise our ability to finance the balance of the operations.

Our focus on structuring financings with investment grade characteristics ensures that debt levels on any particular asset or business can typically be maintained throughout a business cycle, and also enables us to limit covenants and other performance requirements, thereby reducing the risk of early payment requirements or restrictions on the distribution of cash from the assets being financed. Furthermore, our ability to finance at the parent, operating unit, and asset level on a private or public basis means that we are not overly dependent on any particular segment of the capital markets or the performance of any particular unit.

The sustainability of our capital strategy has been demonstrated by the \$8 billion in debt financings raised during 2008 and \$10 billion since August 2007, with proceeds used largely to extend the term of existing obligations and renew financings in the normal course.

To enable us to react to attractive investment opportunities and deal with contingencies when they arise, we typically maintain a high level of liquidity at the corporate level and within our key operating platforms. Our primary sources of liquidity, which we refer to as “core liquidity”, consist of our cash and financial assets, net of deposits and other associated liabilities, and undrawn committed credit facilities.

We generate substantial liquidity within our operations on an ongoing basis through our operating cash flow, which typically exceeds \$1.5 billion on an annual basis, as well as from the turnover of assets with shorter investment horizons and periodic monetization of our longer-dated assets through sales, refinancings or co-investor participations. Accordingly, we believe we have the necessary liquidity to manage our financial commitments and to capitalize on opportunities to invest capital at attractive returns. Nevertheless, we are cognizant of the current instability in the capital markets and continue to place a premium on liquidity and allocate capital in a cautious manner.

LIQUIDITY

Core Liquidity

Our core liquidity was \$2.8 billion as at December 31, 2008, supplemented by a further \$0.7 billion of transactions that have closed or are pending in early 2009. These transactions include the sale of an insurance subsidiary and Brazil transmission lines and recently completed equity and debt financings.

Corporate level liquidity consists of \$1.1 billion of cash and financial assets and \$0.7 billion of undrawn capacity on committed credit facilities as at December 31, 2008. We maintain \$1.4 billion of committed four-year term credit facilities with a group of major financial institutions. These facilities are typically renewed annually for the following four years. Facilities aggregating \$1.2 billion mature in 2012 and \$0.2 billion mature in 2011.

Core liquidity in our main operating units is approximately \$1.0 billion, represented primarily by undrawn credit facilities, with the balance being cash and financial assets. Our North American office property operations maintain \$500 million of committed bank facilities, of which \$234 million was undrawn at year end. Similarly, our renewable power operations hold \$357 million of cash and financial assets and maintain \$375 million of facilities to support forward power sales arrangements and general corporate purposes of which \$129 million was undrawn at year end. We also maintain \$450 million of committed bank facilities within our infrastructure operations, of which \$311 million was undrawn at year end.

Corporate and Subsidiary Debt Maturities

This section summarizes our corporate and subsidiary debt maturities. Corporate maturities and our proportionate share of subsidiary maturities prior to 2012 totalled \$2.3 billion. We expect to refinance or roll over most, if not all, of this debt in the normal course, and that we can fund reductions with our current liquidity.

As shown in the table below, we have no corporate maturities in 2009, a \$200 million bond maturity in 2010 and borrowings under a small number of bank facilities in 2011 that expire if not renewed earlier.

AS AT DECEMBER 31, 2008 (MILLIONS)	2009	2010	2011	2012 and After
Term debt	\$ —	\$ 200	\$ —	\$ 1,435
Commercial paper and bank borrowings	—	—	84	565
Corporate maturities	\$ —	\$ 200	\$ 84	\$ 2,000

The following table presents our proportionate share of subsidiary borrowings, based on our ownership interest in the borrowing entity, adjusted to reflect amortizations and repayments to the date of this report:

AS AT DECEMBER 31, 2008 (MILLIONS)	2009	2010	2011	2012 and After
Brookfield Renewable Power term debt	\$ 282	\$ —	\$ —	\$ 370
Brookfield Australia/term bank facility	231	529	—	—
Brookfield Properties corporate bank facilities	51	—	108	—
Retractable preferred shares	57	—	—	—
Other subsidiary borrowings	261	131	358	1,277
	\$ 882	\$ 660	\$ 466	\$ 1,647

Brookfield Renewable Power has \$282 million of public term notes that mature in December 2009 which we expect to refinance prior to maturity. The substantial cash flow generated within this business and the high quality of its asset base facilitates access to capital markets notwithstanding current volatility and in that regard, we completed a public offering of C\$300 million of 3-year notes in February 2009. The remaining borrowings consist of public notes that mature in 2018 and 2036.

The Brookfield Australia bank facility represents a loan-to-value ratio of less than 50% and the portfolio is well leased with 99% occupancy and an average lease term of seven years. We intend to permanently finance the business with asset-specific mortgages on the properties and corporate facilities prior to 2010.

Brookfield Properties maintains term credit facilities of \$500 million with a group of major financial institutions. The company recently extended \$388 million of the facilities until 2011 and is in discussions to extend the balance. The retractable preferred shares have no mandatory redemption date, although holders have the right to have them redeemed at any time.

Property-specific Debt Maturities

Our debt capitalization is largely in the form of long-term property specific financings that represent low loan-to-value, have few restrictive covenants, are secured by our high quality assets and have no recourse to either the Corporation or our subsidiaries. The following table presents our proportionate share of maturities that occur prior to 2012. We believe these maturities should be refinable at the current levels on an overall basis.

AS AT DECEMBER 31, 2008 (MILLIONS)	2009	2010	2011	2012 and After
Commercial properties				
Office – North America	\$ 277	\$ 29	\$ 1,028	\$ 2,698
Office – Australia	190	972	4	—
Office – Europe	142	56	7	520
Retail – Brazil	30	—	—	123
Power generation				
North America	63	143	58	2,400
Brazil	211	23	23	122
Infrastructure	—	16	14	551
Development and other properties				
North American opportunity funds	8	77	126	224
Residential investing and working capital – Canada	186	24	3	—
Residential investing and working capital – United States	139	112	17	—
Property development – Australia	328	631	—	50
Specialty funds	10	178	—	163
	\$ 1,584	\$ 2,261	\$ 1,280	\$ 6,851

Commercial property financings are secured by high quality office buildings on an individual or, in certain circumstances, pooled basis. Many of the financings which mature in the next three years were arranged a number of years ago and, accordingly, represent a low loan to value. As a result, we expect to refinance most of these maturities in the normal course at the same or a higher level. The average term of financings was seven years as at December 31, 2008. Financings in our North American, European and Brazilian operations, exceeded the average. The Australian property market typically utilizes shorter duration financing, which we are rolling over in the normal course and seeking to extend on a long-term basis where possible.

Within our power generating operations, our proportionate share of maturities for the following three years is modest in the context of our overall portfolio and the facilities are expected to be refinanced at the same or at higher levels given the strong operating margins and cash flows of these properties. The 2009 maturities include \$120 million of acquisition financing put in place to fund the recent purchase of a Brazilian power generating facility at a 42% loan-to-value ratio, which we expect to refinance at similar levels during the second quarter of 2009.

Development and other properties include property-specific borrowings within our opportunity funds, of which only \$211 million are scheduled for repayment before 2012. Our share of residential property borrowings is \$213 million within our Canadian-based residential operations and \$268 million within our U.S. residential business. These borrowings have been reduced substantially over the past 18 months. The residential and property development borrowings are largely of a working capital nature, financing the ongoing development and construction activities, and are typically repaid as the projects, lots or homes being financed are completed and sold, and then re-drawn against any new projects that we elect to pursue.

CAPITALIZATION

The following table presents the components of our capitalization on a deconsolidated, proportionately consolidated and fully consolidated basis. Our consolidated capitalization includes 100% of the debt of consolidated entities, even though in most cases we only own a portion of the entity and therefore our pro rata exposure to this debt is much lower. Furthermore, with very few exceptions, our subsidiary and property-specific borrowings have no recourse to the Corporation.

Accordingly, we believe that the two most meaningful bases of presentation are proportionate consolidation and deconsolidated set out in the following table. In our opinion, the consolidated capitalization is less meaningful and can only be assessed in the context of the overall asset base of the company and taking into consideration the full ownership base, including minority shareholders and institutional fund investors, which can be difficult to assess in the context of historical cost consolidated financial statements.

	<i>Deconsolidated</i>		<i>Proportionate</i>		<i>Consolidated</i>
	<i>Underlying Value</i>	<i>Book Value</i>	<i>Underlying Value</i>	<i>Book Value</i>	<i>Book Value</i>
<i>AS AT DECEMBER 31, 2008 (MILLIONS)</i>					
Corporate borrowings	\$ 2,284	\$ 2,284	\$ 2,284	\$ 2,284	\$ 2,284
Non-recourse borrowings					
Property-specific mortgages	—	—	11,976	11,976	22,889
Subsidiary borrowings ¹	733	733	3,655	3,655	5,102
Accounts payable and other	1,276	1,276	7,061	7,061	9,794
Capital securities	543	543	984	984	1,425
Non-controlling interests	1	1	14	14	6,329
Shareholders' equity	15,021 ²	5,788	15,021 ²	5,788	5,788
	\$ 19,858	\$ 10,625	\$ 40,995	\$ 31,762	\$ 53,611
Debt to capitalization	15%	28%	44%	56%	56%

¹ Includes \$675 million of subsidiary obligations which are guaranteed by the Corporation

² Based on fair values prepared for IFRS purposes

Our strategy of financing at the asset or operating unit level has resulted in us having a relatively low level of debt at the parent company level, as shown in our deconsolidated capitalization. The debt to total capitalization at December 31, 2008 on a deconsolidated basis was 15% based on pre-tax underlying values and 28% based on book values. On a proportionately consolidated basis, the debt to pre-tax underlying value capitalization was 44%, which we believe is appropriate given the quality of our long-term assets and the level of financing that assets of this nature typically support, as well as our liquidity profile. The higher ratio on a book value basis reflects the impact of accounting depreciation on our long life assets as well as the relatively low acquisition prices of assets purchased on an opportunistic basis over the years.

The strong level of cash flows generated within our operations provides favourable interest and fixed charge coverage ratios, as shown in the following table:

	<i>Operating Cash Flow</i>			
	<i>Underlying</i>		<i>Remitted</i>	
	<i>2008</i>	<i>2007</i>	<i>2008</i>	<i>2007</i>
<i>FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)</i>				
Corporate borrowings	\$ 163	\$ 146	\$ 163	\$ 146
Subsidiary borrowings ¹	77	66	77	66
Other liabilities	371	329	371	329
Capital securities	31	32	31	32
Non-controlling interests	—	2	—	2
Shareholders' equity				
Preferred equity	44	44	44	44
Common equity	1,379	1,863	1,220	1,661
Total cash flows	\$ 2,065	\$ 2,482	\$ 1,906	\$ 2,280
Interest coverage ²	9x	12x	8x	11x
Fixed charge coverage ³	7x	9x	6x	8x

¹ Guaranteed by the Corporation or issued by corporate subsidiaries

² Total cash flows divided by interest on corporate and subsidiary borrowings

³ Total cash flows divided by interest on corporate and subsidiary borrowings and distributions on capital securities and preferred equity

Corporate Borrowings

Our corporate borrowings have an average term of nine years (2007 – 11 years) and nearly 90% of the maturities extend into 2012 and beyond. The average interest rate on our corporate borrowings was 5% at year end, compared to 6% at the end of 2007.

<i>AS AT DECEMBER 31 (MILLIONS)</i>	<i>Average Term</i>	<i>Net Invested Capital</i>	
		<i>2008</i>	<i>2007</i>
Commercial paper and bank borrowings	3	\$ 649	\$ 167
Publicly traded term debt	12	1,485	1,881
Privately traded term debt	4	150	—
Total	9	\$ 2,284	\$ 2,048

Corporate debt levels increased by \$236 million during the year to fund our investment activities. We increased our bank borrowings by approximately \$500 million as they represented an attractive and flexible source of capital. We redeemed \$300 million of public bonds upon maturity in December 2008 and replaced this financing with \$150 million of private notes with a blended term and coupon of 4.3 years and 6.5%, respectively, and C\$150 million of 5% capital securities with an expected duration of 5 years.

The Corporation has \$1,445 million of committed corporate three-year and four-year revolving term credit facilities which are utilized principally as back-up credit lines to support commercial paper issuance. At December 31, 2008, \$649 million of these facilities were drawn or allocated as back-up to outstanding commercial paper, and approximately \$104 million (2007 – \$63 million) of the facilities were utilized for letters of credit issued to support various business initiatives.

Subsidiary Borrowings

We capitalize our subsidiary entities to enable continuous access to the debt capital markets, usually on an investment grade basis, thereby reducing the demand for capital from the Corporation and sharing the cost of financing equally among other equity holders in partly owned subsidiaries.

Subsidiary borrowings have no recourse to the Corporation with only a limited number of exceptions. As at December 31, 2008, subsidiary borrowings included \$733 million (2007 – \$711 million) of financial obligations that are either guaranteed by the Corporation or are issued by direct corporate subsidiaries.

AS AT DECEMBER 31 (MILLIONS)	Average Term	Deconsolidated	Proportionate	Consolidated	
		Interest	Interest	2008	2007
		2008	2008		
Subsidiary borrowings					
Commercial properties	1	\$ —	\$ 275	\$ 441	\$ 1,058
Power generation	8	—	652	652	797
Infrastructure	2	—	62	146	8
Development and other properties	2	—	835	1,097	2,337
Specialty funds	3	—	191	386	640
Investments and other	4	—	691	936	763
Corporate subsidiaries ¹	6	733	733	733	711
Co-investor capital					
Properties	5	—	216	711	762
Total	4	\$ 733	\$ 3,655	\$ 5,102	\$ 7,076

¹ Includes \$675 million of subsidiary obligations which are guaranteed by the Corporation

Property-specific Borrowings

As part of our financing strategy, we raise the majority of our debt capital in the form of property-specific mortgages that have recourse only to the assets being financed and have no recourse to the Corporation.

AS AT DECEMBER 31 (MILLIONS)	Average Term	Deconsolidated	Proportionate	Consolidated	
		Interest	Interest	2008	2007
		2008	2008		
Commercial properties	7	\$ —	\$ 6,076	\$ 13,870	\$ 13,841
Power generation	12	—	3,043	3,588	3,488
Infrastructure	9	—	581	1,642	1,796
Development and other properties	2	—	1,925	2,677	2,519
Specialty funds	4	—	351	1,112	—
Total	7	\$ —	\$ 11,976	\$ 22,889	\$ 21,644

We continue to be able to raise property-specific borrowing in the normal course of business notwithstanding the more challenging credit environment, due to the quality of the assets and the sustainability of the cash flows being financed.

Capital Securities

Distributions paid on these securities, which are largely denominated in Canadian dollars, are recorded as interest expense, even though the securities are preferred shares that are convertible into common equity at our option. The securities are classified as liabilities for Canadian GAAP purposes because the holders of the preferred shares have the right, after a fixed date, to convert the shares into common equity based on the market price of our common shares at that time unless previously redeemed by us.

AS AT DECEMBER 31 (MILLIONS)	2008	2007
Issued by the Corporation	\$ 543	\$ 517
Issued by Brookfield Properties	882	1,053
	\$ 1,425	\$ 1,570

During the year we issued C\$150 million of 5% convertible preferred shares. The carrying values of existing capital securities declined due to the lower Canadian dollar, in which most of these securities are denominated.

The average distribution yield on the capital securities at December 31, 2008 was 6% (2007 – 6%) and the average term to the holders' conversion date was six years (2007 – seven years).

Interests of Co-investors

Interests of co-investors in net assets are comprised of two components: participating interests held by other holders in our funds and subsidiary companies, and non-participating preferred equity issued by subsidiaries.

AS AT DECEMBER 31 (MILLIONS)	Number of Shares / % Interest 2008	Brookfield Invested Capital			
		Total		Net	
		2008	2007	2008	2007
Participating interests					
Commercial properties					
Brookfield Properties Corporation	196.6 / 49%	\$ 1,768	\$ 1,622	\$ 1,768	\$ 1,622
Property funds and other	various	437	320	—	—
Power generation	various	192	170	—	—
Infrastructure					
Timberlands	various	995	314	—	—
Transmission	various	246	—	—	—
Development and other properties					
Brookfield Homes Corporation	11.2 / 42%	176	245	—	—
Other		573	650	—	—
Specialty funds	various	1,186	565	—	—
Investments	various	310	346	—	—
		5,883	4,232	1,768	1,622
Non-participating interests					
Brookfield Multiplex Group		324	387	324	387
Brookfield Properties Corporation		122	151	122	151
		446	538	446	538
		\$ 6,329	\$ 4,770	\$ 2,214	\$ 2,160

We include Brookfield Properties on a fully consolidated basis in our segmented basis of presentation and accordingly the interests of others in these operations are reflected in both the total and net results. The other entities shown above are presented on a deconsolidated basis in our segmented analysis, and, as a result, the interests of other shareholders are presented in total invested capital only.

Interests of others in our infrastructure operations increased with the distribution of a 60% interest in Brookfield Infrastructure Partners to our shareholders as well as the transfer of our U.S. Pacific Northwest timber operations to a partially-owned timber fund. Specialty fund interests increased as a result of us commencing reporting our first real estate finance fund on a consolidated basis following a change in ownership during the year and raising additional third-party capital in our second such fund.

Shareholders' Equity

AS AT DECEMBER 31 (MILLIONS)	2008	2007
Preferred equity	\$ 870	\$ 870
Common equity	4,918	6,644

Preferred equity consists of perpetual preferred shares that represent an attractive form of leverage for common shareholders, and was unchanged during the year. The average dividend rate at December 31, 2008 was 5%.

We repurchased 14.2 million common shares during the year at prices ranging from \$12.12 per share to \$35.56 per share, with an average price of \$20.17 per share. Further details on the components of our equity and related distributions can be found on page 54. Common equity also declined as a result of the distribution of a 60% interest in Brookfield Infrastructure by way of a special dividend and the impact of lower foreign currency exchange rates on non-U.S. operations.

AS AT DECEMBER 31, 2008 (MILLIONS, EXCEPT PER SHARE AMOUNTS)

	Total	Per Share
Shareholders' equity		
Underlying value – pre tax	\$ 15,021	\$ 24.32
Underlying value – after tax	12,801	20.62
Book value	5,788	8.93

The underlying value of our equity is \$15.0 billion (\$24.32 per share) on a pre-tax basis and \$12.8 billion (\$20.62 per share) after deducting an accounting provision in respect of the taxes we might theoretically pay if we liquidated the company on the balance sheet date. The market capitalization of our equity, reflecting our share price at year end, was \$10.5 billion. Our book value of \$5.8 billion reflects the depreciated historical cost of many assets, such as office properties and hydroelectric facilities, which were acquired many years ago for values significantly below what they are worth today.

NON-CASH WORKING CAPITAL

Other Assets

The following is a summary of other assets:

AS AT DECEMBER 31 (MILLIONS)	Net Invested Capital	
	2008	2007
Accounts receivable	\$ 678	\$ 795
Restricted cash	294	317
Intangible assets	83	111
Prepaid and other assets	1,105	1,441
Deferred tax asset	408	349
	\$ 2,568	\$ 3,013

Other assets include working capital balances employed in our business that are not directly attributable to specific operating units. The magnitude of these balances varies somewhat based on seasonal variances. The net balances include \$1,161 million (2007 – \$985 million) associated with Brookfield Properties and \$1,407 million (2007 – \$2,028 million) associated with the Corporation.

Other Liabilities

AS AT DECEMBER 31 (MILLIONS)	Invested Capital			
	Total		Net	
	2008	2007	2008	2007
Accounts payable	\$ 3,487	\$ 3,636	\$ 1,101	\$ 1,083
Insurance liabilities	1,132	1,655	—	—
Deferred tax liability	1,461	1,925	365	1,091
Other liabilities	3,714	3,759	1,188	1,308
	\$ 9,794	\$ 10,975	\$ 2,654	\$ 3,482

Accounts payable and other liabilities include \$1,073 million associated with Brookfield Properties (2007 – \$1,398 million). Deferred taxes represent future tax obligations that arise largely due to holding assets whose book value exceeds their value for tax purposes.

PART 4 – ANALYSIS OF CONSOLIDATED FINANCIAL STATEMENTS

The information in this section enables the reader to reconcile the basis of presentation in our consolidated financial statements to that employed in the MD&A. We also provide additional information for certain items not covered within this section. The tables presented on pages 54 and 55 provide a detailed reconciliation between our consolidated financial statements and the basis of presentation throughout the balance of this MD&A.

CONSOLIDATED STATEMENTS OF INCOME

The following table summarizes our consolidated statements of net income:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007	2006
Revenues	\$ 12,868	\$ 9,343	\$ 6,897
Net operating income	4,809	4,509	3,776
Expenses			
Interest	(1,984)	(1,786)	(1,185)
Current income taxes	7	(68)	(142)
Asset management and other operating costs	(640)	(464)	(333)
Non-controlling interests in the foregoing	(791)	(636)	(468)
	1,401	1,555	1,648
Other items, net of non-controlling interests	(752)	(768)	(478)
Net income	\$ 649	\$ 787	\$ 1,170

Revenues

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007	2006
Commercial properties	\$ 2,761	\$ 2,331	\$ 1,500
Power generation	1,286	960	894
Infrastructure	455	599	428
Development and other properties	3,689	2,169	1,788
Specialty funds	2,090	1,246	908
Investment income and other	2,587	2,038	1,379
	\$ 12,868	\$ 9,343	\$ 6,897

Revenues from commercial properties increased due to the expansion of our operations including acquisitions. The increase in power generation revenues reflects higher pricing, higher water flows and increased generating capacity offset by lower currency exchange rates. Infrastructure revenues were higher in 2007 because we consolidated the results of the electricity transmission system in Chile for the first six months of that year and on an equity accounted basis thereafter. Our specialty funds' revenues increased due to the consolidation of revenues from our real estate finance fund during the year.

Net Operating Income

Net operating income includes the following items from our consolidated statements of income: fees earned; operating revenues less direct operating expenses; and investment and other income. These items are described for each business unit in Part 2 – Performance Review beginning on page 12 of this MD&A.

The following table reconciles net operating income to the total operating cash flow in the segmented basis of presentation and net operating income:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	Operating Platform	2008	2007	2006
Net operating income		\$ 4,809	\$ 4,509	\$ 3,776
Add: dividends from equity accounted investments	Investments	22	21	66
exchangeable debenture gains	Cash and Financial Assets	—	331	—
dividends from Canary Wharf	Commercial Properties	—	—	87
Total operating cash flow		\$ 4,831	\$ 4,861	\$ 3,929

Expenses and Other Items

Expenses and Other Items are discussed under Performance Review beginning on page 37 of this MD&A.

CONSOLIDATED BALANCE SHEETS

Total assets at book value decreased to \$53.6 billion as at December 31, 2008 from \$55.6 billion at the end of 2007 as shown in the following table:

AS AT DECEMBER 31 (MILLIONS)	Book Value		
	2008	2007	2006
Assets			
Cash and cash equivalents and financial assets	\$ 2,029	\$ 3,090	\$ 2,869
Investments	890	1,352	775
Accounts receivable and other	7,310	7,139	4,805
Intangible assets	1,632	2,026	1,146
Goodwill	2,011	1,528	669
Operating assets			
Property, plant and equipment	36,375	37,725	28,082
Securities	1,303	1,828	1,711
Loans and notes receivable	2,061	909	651
	\$ 53,611	\$ 55,597	\$ 40,708

The impact of lower currency exchange rates on the carrying values of assets located outside of the United States was a major contributor to the decline in total assets. Carrying values of the associated liabilities also declined, mitigating the impact on our equity.

We commenced accounting for our interests in one of our real estate finance funds and our investment in Norbord on a consolidated basis, which reduced Investments and increased Property, Plant and Equipment as well as Loans and Notes Receivable.

Investments

Investments represent equity accounted interests in partially owned companies as set forth in the following table, which are discussed further within the relevant business segments in the Description of Operating Platforms.

AS AT DECEMBER 31 (MILLIONS)	Business Segment	% of Investment		Book Value	
		2008	2007	2008	2007
Chile transmission	Transmission	17%	28%	\$ 324	\$ 330
Property funds	Commercial Office	20-25%	20-25%	233	382
Brazil transmission	Transmission	3-10%	7.5-25%	207	205
Other	Various			126	107
Norbord Inc.	Investments	—	41%	—	180
Real Estate Finance Fund	Specialty Funds	—	27%	—	148
Total				\$ 890	\$ 1,352

The carrying value of our property fund investments declined due to changes in carrying values and asset valuations. We began accounting for our investments in Norbord and the Real Estate Finance Fund on a consolidated basis following an increase in our ownership in each entity.

Accounts Receivable and Other

AS AT DECEMBER 31 (MILLIONS)	Book Value	
	2008	2007
Accounts receivable	\$ 3,056	\$ 2,892
Prepaid expenses and other assets	2,651	2,813
Restricted cash	610	627
Inventory	993	807
	\$ 7,310	\$ 7,139

These balances include amounts receivable by the company in respect of contracted revenues owing but not yet collected, and dividends, interest and fees owing to the company. Prepaid expenses and other assets include amounts accrued to reflect the straight-lining of long-term contracted revenues and capitalized lease values in accordance with accounting guidelines. Restricted cash represents cash balances placed on deposit in connection with financing arrangements and insurance contracts, including the defeasement of long-term property-specific mortgages. The distribution of these assets among our business units is presented in the tables on page 54.

Goodwill

Goodwill represents purchase consideration that is not specifically allocated to the tangible and intangible assets being acquired. The balance as at December 31, 2008 includes \$799 million of goodwill allocated to our Australian, European and Middle East operations and \$591 million of goodwill incurred on the acquisition of U.S. Pacific Northwest timberlands.

Property, Plant and Equipment

AS AT DECEMBER 31 (MILLIONS)	Book Value	
	2008	2007
Commercial properties	\$ 19,274	\$ 20,796
Power generation	4,954	5,137
Infrastructure	2,879	3,046
Development and other properties	7,282	7,696
Other plant and equipment	1,986	1,050
	\$ 36,375	\$ 37,725

The changes in these balances are discussed within each of the relevant business units within the Operating Platforms section. Commercial properties includes office and retail property assets. Development and other properties include opportunity investments, residential properties, properties under development and properties held for development. The increase in other plant and equipment is largely due to the consolidation of Norbord during 2008.

Securities

Securities include \$1.0 billion (2007 – \$1.6 billion) of largely fixed income securities held through our insurance operations, as well as our \$143 million (2007 – \$182 million) common share investment in Canary Wharf Group, which is included in our commercial office property operations in our segmented analysis, and is carried at historic cost, adjusted to reflect current exchange rates.

Loans and Notes Receivable

Loans and notes receivable consist largely of loans advanced by our bridge lending operations and real estate securities. The balances increased during the year following the consolidation of our first real estate finance fund.

CONSOLIDATED STATEMENTS OF CASH FLOWS

The following table summarizes the company's cash flows on a consolidated basis:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007
Operating activities	\$ 1,567	\$ 3,284
Financing activities	(1,121)	4,471
Investing activities	(765)	(7,398)
(Decrease) Increase in cash and cash equivalents	\$ (319)	\$ 357

We completed two major acquisitions in 2007, which resulted in a significantly higher level of aggregate financing and investment activities in that year compared to 2008. The decline in cash flow from operations is due to a smaller change in working capital balances.

Operating Activities

Cash flow from operating activities is reconciled to the operating cash flow measure utilized elsewhere in this report as follows:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007
Operating cash flow	\$ 1,423	\$ 1,907
Adjust for:		
Net change in working capital balances and other	(279)	1,141
Realization gains	(164)	(231)
Undistributed non-controlling interests in cash flow	587	467
Cash flow from operating activities	\$ 1,567	\$ 3,284

Operating cash flow is discussed in detail elsewhere in this MD&A.

We retained \$587 million (2007 – \$467 million) of operating cash flow within our consolidated subsidiaries attributable to minority interests in excess of that distributed by way of dividends.

Financing Activities

We utilized \$1.1 billion of cash within our financing activities during 2008, compared to the generation of \$4.5 billion in 2007. The 2007 results reflected proceeds from financings completed in respect of acquisitions during that year, including a major property business in Australia, retail properties in Brazil and timberlands in the US Pacific Northwest.

During 2008 we reduced the leverage in several of our operations in response to the deteriorating economic climate and through the retirement of debt associated with assets sold during the year. We also purchased a larger amount of common shares of the Corporation and our subsidiaries.

Investing Activities

We invested net capital of \$0.8 billion on a consolidated basis during 2008, compared with a net investment of \$7.4 billion during 2007. We increased our investment in power generating facilities through the acquisition of a 156 megawatt facility in Brazil, resulting in cash outflow of \$0.5 billion and invested additional capital through the development of our commercial office portfolio. In addition, we sold a partial interest in our U.S. Pacific Northwest timberlands for gross proceeds of \$0.6 billion. The most significant acquisitions in 2007 included that of Multiplex, a major retail property portfolio in Brazil and U.S. timberlands.

RECONCILIATION OF SEGMENTED DISCLOSURE TO CONSOLIDATED FINANCIAL STATEMENTS

Balance Sheet

AS AT DECEMBER 31, 2008

(MILLIONS)	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Cash and Financial Assets	Other Assets	Corporate	Consolidated
Assets										
Operating assets										
Property, plant and equipment										
Commercial properties	\$ 19,274	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 19,274
Power generation	—	4,954	—	—	—	—	—	—	—	4,954
Infrastructure	—	—	2,879	—	—	—	—	—	—	2,879
Development and other properties	38	—	105	7,092	—	47	—	—	—	7,282
Other plant and equipment	10	—	—	49	709	1,218	—	—	—	1,986
Securities	143	—	—	—	206	954	—	—	—	1,303
Loans and notes receivable	—	—	—	—	1,921	24	116	—	—	2,061
Cash and cash equivalents	166	138	61	160	124	270	323	—	—	1,242
Financial assets	24	219	—	(305)	91	(35)	793	—	—	787
Investments	252	—	544	37	27	2	28	—	—	890
Accounts receivable and other	96	1,135	228	2,217	726	808	—	2,100	—	7,310
Goodwill	121	27	591	834	23	30	—	385	—	2,011
Intangible assets	859	—	5	560	112	13	—	83	—	1,632
Total assets	\$ 20,983	\$ 6,473	\$ 4,413	\$ 10,644	\$ 3,939	\$ 3,331	\$ 1,260	\$ 2,568	\$ —	\$ 53,611
Liabilities and shareholders' equity										
Corporate borrowings	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 2,284	\$ 2,284
Property-specific financing	13,536	3,587	1,642	3,011	1,113	—	—	—	—	22,889
Other debt of subsidiaries	1,118	653	145	1,131	387	746	189	—	733	5,102
Accounts payable and other liabilities	1,318	826	624	2,419	380	1,573	—	—	2,654	9,794
Capital securities	—	—	—	—	—	—	—	—	1,425	1,425
Non-controlling interests in net assets	436	192	1,241	749	1,189	310	(2)	—	2,214	6,329
Preferred equity	—	—	—	—	—	—	—	—	870	870
Common equity / net invested capital	4,575	1,215	761	3,334	870	702	1,073	2,568	(10,180)	4,918
Total liabilities and shareholders' equity	\$ 20,983	\$ 6,473	\$ 4,413	\$ 10,644	\$ 3,939	\$ 3,331	\$ 1,260	\$ 2,568	\$ —	\$ 53,611

AS AT DECEMBER 31, 2007

(MILLIONS)	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Cash and Financial Assets	Other Assets	Corporate	Consolidated
Assets										
Operating assets										
Property, plant and equipment										
Commercial properties	\$ 20,796	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 20,796
Power generation	—	5,137	—	—	—	—	—	—	—	5,137
Infrastructure	—	—	3,046	—	—	—	—	—	—	3,046
Development and other properties	—	—	106	7,512	—	78	—	—	—	7,696
Other plant and equipment	8	—	—	10	632	398	2	—	—	1,050
Securities	182	—	—	—	—	1,646	—	—	—	1,828
Loans and notes receivable	—	—	—	—	856	53	—	—	—	909
Cash and cash equivalents	146	77	38	447	74	237	360	182	—	1,561
Financial assets	—	707	—	(41)	180	—	683	—	—	1,529
Investments	382	—	535	30	169	194	42	—	—	1,352
Accounts receivable and other	94	848	113	1,426	794	1,186	305	2,373	—	7,139
Goodwill	—	33	591	521	—	36	—	347	—	1,528
Intangible assets	1,012	—	6	868	6	23	—	111	—	2,026
Total assets	\$ 22,620	\$ 6,802	\$ 4,435	\$ 10,773	\$ 2,711	\$ 3,851	\$ 1,392	\$ 3,013	\$ —	\$ 55,597
Liabilities and shareholders' equity										
Corporate borrowings	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 2,048	\$ 2,048
Property-specific financing	13,841	3,488	1,796	2,519	—	—	—	—	—	21,644
Other debt of subsidiaries	1,820	797	9	2,337	637	371	394	—	711	7,076
Accounts payable and other liabilities	1,779	879	668	1,791	434	1,877	65	—	3,482	10,975
Capital securities	—	—	—	—	—	—	—	—	1,570	1,570
Non-controlling interests in net assets	582	213	317	662	528	267	41	—	2,160	4,770
Preferred equity	—	—	—	—	—	—	—	—	870	870
Common equity / net invested capital	4,598	1,425	1,645	3,464	1,112	1,336	892	3,013	(10,841)	6,644
Total liabilities and shareholders' equity	\$ 22,620	\$ 6,802	\$ 4,435	\$ 10,773	\$ 2,711	\$ 3,851	\$ 1,392	\$ 3,013	\$ —	\$ 55,597

Results from Operations

FOR THE YEAR ENDED DECEMBER 31, 2008

(MILLIONS)	Asset Management	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Investment Income / Gains	Corporate	Consolidated
Fees earned	\$ 449	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 449
Revenues less direct operating costs										
Commercial properties	—	1,831	—	—	—	—	—	—	—	1,831
Power generation	—	—	886	—	—	—	—	—	—	886
Infrastructure	—	—	—	196	—	—	—	—	—	196
Development and other properties	—	(1)	—	5	234	—	2	—	—	240
Specialty funds	—	—	—	—	—	304	—	—	—	304
Investment and other income	—	53	—	134	(25)	3	219	519	—	903
	449	1,883	886	335	209	307	221	519	—	4,809
Expenses										
Interest	—	1,033	313	102	50	88	22	48	328	1,984
Asset management and other operating costs	—	—	—	15	—	—	19	—	606	640
Current income taxes	—	15	21	13	(73)	4	3	—	10	(7)
Non-controlling interests	—	72	86	64	27	89	19	(16)	450	791
	449	763	466	141	205	126	158	487	(1,394)	1,401
Dividends	—	—	—	—	—	—	22	—	—	22
Cash flow from operations	\$ 449	\$ 763	\$ 466	\$ 141	\$ 205	\$ 126	\$ 180	\$ 487	\$(1,394)	\$ 1,423

Results from Operations

FOR THE YEAR ENDED DECEMBER 31, 2007

(MILLIONS)	Asset Management	Commercial Properties	Power	Infrastructure	Development and Other	Specialty Funds	Investments	Investment Income / Gains	Corporate	Consolidated
Fees earned	\$ 415	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 415
Revenues less direct operating costs										
Commercial properties	—	1,548	—	—	—	—	—	—	—	1,548
Power generation	—	—	611	—	—	—	—	—	—	611
Infrastructure	—	—	—	290	—	—	—	—	—	290
Development and other properties	—	—	—	7	419	—	(9)	1	—	418
Specialty funds	—	—	—	—	—	370	—	—	—	370
Investment and other income	—	18	—	21	(7)	11	437	377	—	857
	415	1,566	611	318	412	381	428	378	—	4,509
Expenses										
Interest	—	870	289	174	72	22	44	13	302	1,786
Asset management and other operating costs	—	—	—	—	—	—	23	—	441	464
Current income taxes	—	10	7	4	(18)	4	49	3	9	68
Non-controlling interests	—	84	54	38	57	14	21	—	368	636
	415	602	261	102	301	341	291	362	(1,120)	1,555
Dividends	—	—	—	—	—	—	21	—	—	21
Xstrata debenture gain	—	—	—	—	—	—	—	331	—	331
Cash flow from operations	\$ 415	\$ 602	\$ 261	\$ 102	\$ 301	\$ 341	\$ 312	\$ 693	\$(1,120)	\$ 1,907

PART 5 – BUSINESS STRATEGY, ENVIRONMENT AND RISKS

In this section we discuss our business strategy, our capabilities as they relate to our ability to execute our strategy, the key performance factors that form an integral part of this strategy and key financial measures that are indicative of our progress. This section also contains a review of certain aspects of the business environment and risks that could affect our performance.

BUSINESS STRATEGY

We are a global asset management company focused on property, renewable power and infrastructure assets. Our goal is to establish Brookfield as a global asset manager of choice for investment clients who wish to benefit from the ownership of these types of assets. We have spent many years building high quality operating platforms that enable us to acquire, finance and optimize the value of assets for our own benefit, and for our clients whose capital we manage.

We believe that the best way to create long-term shareholder value is to generate increasing operating cash flows, measured on a per share basis, over a very long period of time. Accordingly, we concentrate on high quality long-life assets that generate sustainable cash flows, require minimal sustaining capital expenditures and tend to appreciate in value over time. Often these assets will benefit from some form of barrier to entry due to regulatory, physical or cost structure factors. While high quality assets may initially generate lower returns on capital, we believe that the sustainability and future growth of their cash flows are more assured over the long term, and as a result, warrant higher valuation levels. We also believe that the high quality of our asset base protects the company against future uncertainty and enables us to invest with confidence when opportunities arise.

Consistent with this focus, we own and operate large portfolios of core office properties, hydroelectric power generating stations, private timberlands and regulated transmission systems that, in our opinion, share these common characteristics. These assets represent important components of the infrastructure that supports the global economy.

We believe the demand from institutional investors to own assets of this nature is increasing as they seek to earn increasing yields to meet their investment objectives. These assets, in our view, represent attractive alternatives to traditional fixed income investments, providing in many cases a “real return” that increases over time, relatively low volatility and strong capital protection. There is a substantial supply of investment opportunities in the form of existing assets as well as the need for continued development in an ever expanding global economy. At the same time there are relatively few global organizations focused on managing assets of this nature as a primary component of their strategy.

Accordingly, an important component of our long-term strategy for growth is centred around expanding our assets under management, which should lead to increased fee revenues and long-term opportunities to earn performance returns. We plan to achieve this within our existing operating platforms, through geographic expansion beyond our current focus in North America, South America, Europe and Australia, and by developing and acquiring platforms to operate new asset classes that demonstrate characteristics that are similar to our existing assets. We also plan to achieve growth by expanding our distribution capabilities to access a broader range of investment partners, thereby increasing our access to capital. This increased capital, when coupled with new investment opportunities, should increase our assets under management and the associated income as well as direct investment returns, thereby increasing shareholder value.

Capabilities

We believe that we have the necessary capabilities to execute our business strategy and achieve our performance targets. We focus on disciplined and active hands-on management of assets and capital. We strive for excellence and quality in each of our core operating platforms in the belief that this approach will produce superior returns over the long term.

We endeavour to operate as a value investor and follow a disciplined investment approach. Our management team has considerable capabilities in investment analysis, mergers and acquisitions, divestitures and corporate finance that enable us to acquire assets for value, finance them effectively, and to ultimately realize value created during our ownership.

Our operating platforms and depth of experience in managing these assets differentiate us from some competitors that have shorter investment horizons and more of a financial focus. Over time we have established a number of high quality operating platforms that are fully integrated into our organization. This has required considerable investment in building the management teams and the necessary resources; however, we believe these platforms enable us to optimize the cash returns and values of the assets that we manage.

We have established strong relationships with a number of leading institutions and believe we are well positioned to expand our sources of co-investment capital and clients. In order to expand our assets under management, we are investing in our distribution capabilities to encourage existing and potential clients to commit capital to our investment strategies. We are devoting expanded resources to these activities, and our efforts continue to be assisted by strong investment performance.

The diversification within our operations allows us to offer a broad range of products and investment strategies to our clients. We believe this is of considerable value to investors with large amounts of capital to deploy. In addition, our commitment to transparency and governance as a well-capitalized public company listed on major North American and European stock exchanges positions us as a desirable long-term partner for our clients.

Finally, our commitment to invest a meaningful amount of capital alongside our investors creates a strong alignment of interest between us and our investment partners and also differentiates us from many of our competitors. Accordingly, our strategy calls for us to maintain considerable surplus financial resources relative to other managers. This capital also supports our ability to commit to investment opportunities on our own account when appropriate or in anticipation of future syndications.

Key Performance Factors

Our ability to increase our operating cash flows is impacted by our ability to generate attractive returns on the capital invested on behalf of ourselves and our clients, and our ability to increase the amount of the capital that we manage on behalf of our clients. These two criteria are linked, in that the quality of our investment returns will encourage clients to commit capital to us, and our access to this capital will enable us to pursue a broader range of investment opportunities.

Investment returns are influenced by a number of factors that are specific to each asset and industry segment. There are however, four key objectives that we focus on across the organization.

- Acquire assets “for value”: meaning that the projected cash flows and value appreciation of the asset represent an attractive risk-adjusted return to ourselves and our co-investors.
- Optimize the cash returns and value of the asset on an ongoing basis. In most cases, this is the responsibility of one of our operating platforms, and is evidenced by the return on asset metrics and operating margins.
- Finance assets effectively, using a prudent amount of leverage. We believe this is very important in maximizing the net returns to investors from property and infrastructure assets, given the lower return on assets compared to a number of other businesses. Fortunately, these assets are well suited to support a relatively high level of investment grade secured debt with long maturity dates given the predictability of the cash flows and tendency of these assets to retain substantial value throughout economic cycles. This is reflected in our return on net capital deployed, our overall return on capital and our cost of capital.
- Have the ability to realize the maximum value of assets through a direct or indirect sale or monetization of the assets. Many of our assets tend to appreciate in value over time and accordingly they may be held for very long periods of time. As a result, this “back-end” appreciation may not be recognized in our financial results until there is a specific transaction.

Expanding our client relationships is impacted not only by our investment returns, as discussed above, but also by the quality of our distribution capabilities and by maintaining a high level of ongoing client service. This involves transparent and timely communication of results, ongoing engagement and responsiveness to client objectives and generation of attractive investment opportunities.

Key Financial Measures

Our key performance measure is the long-term growth rate of operating cash flow on a per share basis. We also measure the cash return on book equity, which demonstrates how effective we are at deploying the capital with which we have been entrusted by shareholders. Our current targets are 12% and 20%, respectively. We revisit these targets periodically in light of the current operating environment to ensure that they are realistic and can be achieved without exposing the organization to inappropriate risk.

The amount of co-investor capital commitments is also an important measure. One of our most important objectives is to expand the amount of capital committed to us by our clients because this provides us with capital to expand our business and also entitles us to earn asset management income based on our ability to successfully invest this capital. “Third-Party” asset management

income is an important measure in that it is indicative of the cash flow generated from our asset management activities, which is an important source of potential growth in our operating cash flows.

We utilize operating cash flow as a key operating metric as opposed to net income, principally because operating cash flow does not include certain items that we believe can distort operations results, such as depreciation and amortization expense, and future income tax expense.

Depreciation as prescribed by GAAP, for example, implies these assets decline in value on a pre-determined basis over time, whereas we believe that the value of most of our assets, as long as regular sustaining capital expenditures are made, will typically increase over time. This increase in value will inevitably vary based on a number of market and other conditions that cannot be determined in advance, and may sometimes be negative in a particular period. Future income tax expense, in our case, is derived primarily from changes in the magnitude and quality of our tax losses and the differences between the tax values and book values of our assets, as opposed to current cash liabilities. Brookfield has access to significant tax shields as a result of the nature of our asset base, and we do not expect to incur any meaningful cash tax liability in the near future from ongoing operations.

Our operating cash flow is derived from two principal activities: operations and asset management. We invest our own capital in most of the assets and capital that we manage for our clients, and accordingly participate in the operating cash flow produced by these assets and businesses and the associated value appreciation. In addition, our clients compensate us for asset management activities that we perform in respect of the capital and assets that we manage on their behalf. Accordingly, we distinguish operating cash flows between those attributable to our asset management activities and those that represent investment returns from the capital deployed in established funds and directly held assets. Asset management activities include strategic oversight, investment analysis, capital allocation activities such as acquisitions, divestitures and financing, and the provision of specific services such as investment banking, facilities management and leasing. While currently modest, we intend to significantly increase the contribution from asset management as we continue to expand these activities.

BUSINESS ENVIRONMENT AND RISKS

The following is a review of certain risks that could adversely impact our financial condition, results of operation and the value of our common shares. Additional risks and uncertainties not previously known to the Corporation, or that the Corporation currently deems immaterial, may also impact our operations and financial results.

General Risks

We are exposed to the local, regional, national and international economic conditions and other events and occurrences that affect the markets in which we own assets and operate businesses. In general, a protracted decline in economic conditions will result in downward pressure on our operating margins and asset values as a result of lower demand for the services and products that we provide. We believe that the long-life nature of our assets and, in many cases, the long-term nature of revenue contracts mitigates this risk to some degree.

Each segment of our business is subject to competition in varying degrees. This can result in downward pressure on revenues which can, in turn, reduce operating margins and thereby reduce operating cash flows and investment returns. In addition, competition could result in scarcity of inputs which can impact certain of our businesses through higher costs. We believe that the high quality and low operating costs of many of our assets and businesses provides some measure of protection in this regard.

A number of our long-life assets are interest rate sensitive: an increase in long-term interest rates will, absent all else, tend to decrease the value of the assets. We mitigate this risk in part by financing assets with long-term fixed rate debt, which will typically decrease in value as rates increase. In addition, we believe that many conditions that lead to higher interest rates, such as inflation, can also give rise to higher revenues which will, absent all else, tend to increase values.

The trading price of our common shares in the open market cannot be predicted. The trading price could fluctuate significantly in response to factors such as: variations in our quarterly or annual operating results and financial condition; changes in government regulations affecting our business; the announcement of significant events by our competitors; market conditions and events specific to the industries in which we operate; changes in general economic conditions; differences between our actual financial and operating results and those expected by investors and analysts; changes in analysts' recommendations or projections; the depth and liquidity of the market for our common shares; investor perception of our business and industry; investment restrictions; and our dividend policy. In addition, securities markets have experienced significant price and volume fluctuations in recent years

that have often been unrelated or disproportionate to the operating performance of particular companies. These broad fluctuations have, in the past, and may, in the future, adversely affect the trading price of our common shares.

Execution of Strategy

Our strategy for building shareholder value is to acquire or develop high quality assets and businesses that generate sustainable and increasing cash flows on behalf of ourselves and co-investors, with the objective of achieving higher returns on invested capital and increasing asset management fees over the long term.

We consider effective capital allocation to be one of the most important components to achieving long-term investment success. As a result, we apply a rigorous approach towards the allocation of capital among our operations. Capital is invested only when the expected returns exceed pre-determined thresholds, taking into consideration both the degree and magnitude of the relative risks and upside potential and, if appropriate, strategic considerations in the establishment of new business activities.

The successful execution of a value investment strategy requires careful timing and business judgment, as well as the resources to complete asset purchases and restructure them as required, notwithstanding difficulties experienced in a particular industry. Our diversified business base, liquidity and the sustainability of our cash flows provide important elements of strength.

We endeavour to maintain an appropriate level of liquidity in order to invest on a value basis when attractive opportunities arise. Our approach to business entails adding assets to our existing businesses when the competition for assets is lowest, either due to depressed economic conditions or when concerns exist relating to a particular industry. However, there is no certainty that we will be able to acquire or develop additional high quality assets at attractive prices to supplement our growth. Conversely, overly favourable economic conditions can limit the number of attractive investment opportunities and thereby restrict our ability to increase assets under management and the related income streams. Competition from other well-capitalized investors may significantly increase the purchase price or prevent us from completing an acquisition. We may be unable to finance acquisitions on favourable terms, or newly acquired assets and businesses may fail to perform as expected. We may underestimate the costs necessary to bring an acquisition up to standards established for its intended market position or may be unable to quickly and efficiently integrate new acquisitions into our existing operations.

We develop property and power generation assets. In doing so, we must comply with extensive and complex regulations affecting the development process. These regulations impose on us additional costs and delays, which may adversely affect our business and results of operations. In particular, we are required to obtain the approval of numerous governmental authorities regulating matters such as permitted land uses, levels of density, the installation of utility services, zoning and building standards. We must comply with local, state and federal laws and regulations concerning the protection of health and the environment, including laws and regulations with respect to hazardous or toxic substances. These environmental laws and regulations sometimes result in delays, which cause us to incur additional costs, or severely restrict development activity in environmentally sensitive regions or areas.

Our ability to successfully expand our asset management business is dependent on our reputation with our current and potential investment partners. We believe that our track record and recent investments, as well as adherence to operating principles that emphasize a constructive management culture, will enable us to continue to develop productive relationships with institutional investors. However, competition for institutional capital, particularly in the asset classes on which we focus, is intense. Although we seek to differentiate ourselves there is no assurance that we will be successful in doing so and this competition may reduce the margins of our asset management business and may decrease the extent of institutional investor involvement in our activities.

The decline in market value of financial instruments and other investments has had an adverse effect on the investment portfolios of the insurance companies, pension funds, endowments, sovereign wealth funds and other institutional investors that we seek to partner with in our investments. In the long run, we believe that investors will be increasingly attracted to our approach to asset management which focuses on high quality real assets, conservative financing and an operations-based approach to creating value. In the nearer term, however, the financial market dynamics may reduce the ability of our investment partners to commit to new investments unless they are pursuant to existing commitments. This has reduced our ability to expand our asset management platform.

Our executive and other senior officers have a significant role in our success. Our ability to retain our management group or attract suitable replacements should any members of the management group leave is dependent on the competitive nature of the

employment market. The loss of services from key members of the management group or a limitation in their availability could adversely impact our financial condition and cash flow. Further, such a loss could be negatively perceived in the capital markets. The conduct of our business and the execution of our growth strategy rely heavily on teamwork. Co-operation amongst our operations and our team-oriented management structure are essential to responding promptly to opportunities and challenges as they arise. We believe that our hiring and compensation practices encourage retention and teamwork.

We participate in joint ventures, partnerships, co-tenancies and funds affecting many of our assets and businesses. Investments in partnerships, joint ventures, co-tenancies or other entities may involve risks not present were a third-party not involved, including the possibility that our partners, co-tenants or co-venturers might become bankrupt or otherwise fail to fund their share of required capital contributions. Additionally, our partners, co-venturers or co-tenants might at any time have different economic or other business interests or goals. In addition, we do not have sole control of certain major decisions relating to these assets and businesses, including: decisions relating to the sale of the assets and businesses; refinancing; timing and amount of distributions of cash from such entities to the Corporation; and capital expenditures.

Some of our management arrangements permit our partners to terminate the management agreement in limited circumstances relating to enforcement of the managers' obligations. In addition, the sale or transfer of interests in some of our entities is subject to rights of first refusal or first offer and some agreements provide for buy-sell or similar arrangements. Such rights may be triggered at a time when we may not want to sell but may be forced to do so because we may not have the financial resources at that time to purchase the other party's interest. Such rights may also inhibit our ability to sell our interest in an entity within our desired time frame or on any other desired basis.

Financial and Liquidity Risks

We employ debt and other forms of leverage in the ordinary course of our business in order to enhance returns to shareholders and our co-investors. We attempt to match the profile of the leverage to the associated assets and accordingly typically fund shorter-duration floating rate assets with shorter-term floating rate debt and fund long-term fixed rate and equity-like assets with long-term fixed rate and equity capital. Most of the debt within our business has recourse only to the assets or subsidiary being financed and has no recourse to the Corporation.

Accordingly, we are subject to the risks associated with debt financing. These risks, including the following, may adversely affect our financial condition and results of operations: our cash flow may be insufficient to meet required payments of principal and interest; payments of principal and interest on borrowings may leave us with insufficient cash resources to pay operating expenses; we may not be able to refinance indebtedness on our assets at maturity due to company and market factors including: the estimated cash flow of our assets; the value of our assets; liquidity in the debt markets; financial, competitive, business and other factors, including factors beyond our control; and if refinanced, the terms of a refinancing may not be as favourable as the original terms of the related indebtedness. We attempt to mitigate these risks through the use of long-term debt and by diversifying our maturities over an extended period of time. We also strive to maintain adequate liquidity to refinance obligations.

The terms of our various credit agreements and other financing documents require us to comply with a number of customary financial and other covenants, such as maintaining debt service coverage and leverage ratios, insurance coverage and, in limited circumstances, rating levels. These covenants may limit our flexibility in our operations, and breaches of these covenants could result in defaults under the instruments governing the applicable indebtedness even if we had satisfied our payment obligations.

If we are unable to refinance our indebtedness on acceptable terms, or at all, we may need to utilize available liquidity, which would reduce our ability to pursue new investment opportunities, or dispose of one or more of our assets upon disadvantageous terms. Moreover, prevailing interest rates or other factors at the time of refinancing could increase our interest expense, and if we pledge assets to secure payment of indebtedness and are unable to make required payments, the creditor could foreclose upon such asset or appoint a receiver to receive an assignment of the associated cash flows.

A large proportion of our capital is invested in physical assets which can be hard to sell, especially if local market conditions are poor. Such liquidity could limit our ability to vary our portfolio or assets promptly in response to changing economic or investment conditions. Additionally, financial or operating difficulties of other owners resulting in distress sales could depress asset values in the markets in which we operate in times of illiquidity. These restrictions could reduce our ability to respond to changes in the performance of our investments and market conditions and could adversely affect our financial condition and results of operations.

We periodically enter into agreements that commit us to acquire assets or securities. In some cases we may enter into such agreements with the expectation that we will syndicate or assign all or a portion of our commitment to other investors prior to, at the same time as, or subsequent to the anticipated closing. We may be unable to complete this syndication or assignment which may increase the amount of capital that we are required to invest. These activities can have an adverse impact on our liquidity which may reduce our ability to pursue further acquisitions or meet other financial commitments.

We periodically enter into joint venture, consortium or other arrangements that have contingent liquidity rights in our favour or in favour of our counterparties that may have implications for us. These include buy-sell arrangements, put and call rights, en-bloc sale rights, registration rights and other customary arrangements. A counterparty may seek to exercise these rights in response to their own liquidity considerations or other reasons internal to the counterparty. Our agreements generally have embedded protective terms that mitigate the risk to us. However, in some circumstances we may need to utilize some of our own liquidity in order to preserve value or protect our interests.

We enter into financing commitments in the normal course of business and, as a result, may be required to fund these. Although we do not typically do so, we from time to time guarantee the obligations of funds or other entities that we manage and/or invest in. If we are unable to fulfill any of these commitments, this could result in damages being pursued against us or a loss of opportunity through default of contracts that are otherwise to our benefit.

Our business is impacted by changes in currency rates, interest rates, commodity prices and other financial exposures. We selectively utilize financial instruments to manage these exposures. The company's risk management and derivative financial instruments are more fully described in the notes to our Consolidated Financial Statements.

We have pursued and intend to continue to pursue growth opportunities in international markets and often invest in countries where the U.S. dollar is not the notional currency. As a result, we are subject to foreign currency risk due to potential fluctuations in exchange rates between foreign currencies and the U.S. dollar. A significant depreciation in the value of the foreign currency of one or more countries where we have a significant investment may have a material adverse effect on our results of operations and financial position. We attempt to mitigate adverse effects by borrowing under debt agreements denominated in foreign currencies and through the use of financial contracts, however, there can be no assurance that those attempts to mitigate foreign currency risk will be successful.

We typically finance assets that generate predictable long-term cash flows with long-term fixed rate debt in order to provide stability in cash flows and protect returns in the event of changes in interest rates. We also make use of fixed rate preferred equity financing as well as financial contracts to provide additional protection in this regard. Similarly, we typically finance shorter term floating rate assets with floating rate debt.

As at December 31, 2008, our net floating rate liability position was \$1.8 billion (2007 – asset of \$0.2 billion). As a result, a 10 basis point increase in interest rates would decrease operating cash flow by \$18 million. We are required to record certain financial instruments at market value and any changes in value recorded as current income, with the result that a 10 basis point increase in long-term interest rates will result in a corresponding increase in income of \$7 million before tax and vice versa, based on our year end positions.

We selectively utilize credit default swaps and other derivatives to hedge financial positions and may establish unhedged positions from time to time. These instruments are typically utilized as a hedge or an alternative to purchasing or selling the underlying security when they are more effective from a capital employment perspective.

Commercial Office Properties

Our strategy is to invest in high quality commercial office properties as defined by the physical characteristics of the assets and, more importantly, the certainty of receiving rental payments from large corporate tenants which these properties attract. Nonetheless, we remain exposed to certain risks inherent in the commercial office property business.

Commercial office property investments are generally subject to varying degrees of risk depending on the nature of the property. These risks include changes in general economic conditions (such as the availability and cost of mortgage funds), local conditions (such as an oversupply of space or a reduction in demand for real estate in markets in which we operate), the attractiveness of the properties to tenants, competition from other landlords and our ability to provide adequate maintenance at an economical cost.

Certain significant expenditures, including property taxes, maintenance costs, mortgage payments, insurance costs and related charges, must be made regardless of whether or not a property is producing sufficient income to service these expenses. Our commercial office properties are subject to mortgages which require substantial debt service payments. If we become unable or unwilling to meet mortgage payments on any property, losses could be sustained as a result of the mortgagee's exercise of its rights of foreclosure or of sale. We believe the stability and long-term nature of our contractual revenues is an effective mitigant to these risks.

Our commercial office properties generate a relatively stable source of income from contractual tenant rent payments. We endeavour to stagger our lease expiry profile so that we are not faced with a disproportionate amount of space expiring in any one year. Continued growth of rental income is dependent on strong leasing markets to ensure expiring leases are renewed and new tenants are found promptly to fill vacancies. While we believe the long-term outlook for commercial office rents is positive, it is possible that rental rates could decline, tenant bankruptcies could increase or that renewals may not be achieved particularly in an event of a protracted disruption in the economy such as the onset of a recession. The company is, however, substantially protected against short-term market conditions, since most of our leases are long-term in nature.

Our commercial office portfolio is concentrated in large metropolitan areas, some of which have been or may be perceived to be subject to terrorist attacks. Furthermore, many of our properties consist of high-rise buildings, which may also be subject to this actual or perceived threat, which could be heightened in the event that the United States continues to engage in armed conflict. This could have an adverse effect on our ability to lease office space in our portfolio. Each of these factors could have an adverse impact on our operating results and cash flows. Our commercial office property operations have insurance covering certain acts of terrorism for up to \$500 million of damage and business interruption costs. We continue to seek additional coverage equal to the full replacement cost of our assets; however, until this type of coverage becomes commercially available on a reasonably economic basis, any damage or business interruption costs as a result of uninsured acts of terrorism could result in a material cost to the company.

Power Generating Operations

Our power generating operations, which are primarily hydroelectric generating facilities, are subject to changes in hydrology and price, but also including equipment and dam failure, counterparty performance, water rental costs, changes in regulatory requirements and other material disruptions.

The revenues generated by our power facilities are correlated to the amount of electricity generated, which in turn is dependent upon available water flows. Hydrology has natural variation from year to year and may also change permanently because of climate change or other factors, and a natural disaster could impact water flows within the watersheds in which we operate.

A significant portion of our power generating operation revenues are tied, either directly or indirectly, to the wholesale market price for electricity in the markets in which we operate. Wholesale market electricity prices are impacted by a number of external factors. As a result, we cannot accurately predict future electricity prices.

There is a risk of equipment failure or dam failure due to wear and tear, latent defect, design error or operator error, among other things. The occurrence of such failures could result in a loss of generating capacity and repairing such failures could require the expense of significant amounts of capital and other resources. Such failures could result also in exposure to significant liability for damages.

A significant portion of the power we generate is sold under long-term power purchase agreements, as well as shorter-term financial instruments and physical electricity and natural gas contracts that are above market. If for any reason any of the counterparties are unable or unwilling to fulfill their contractual obligations, we may not be able to replace the agreement with an agreement on equivalent terms and conditions.

We are required to make rental payments and pay property taxes for water rights or pay similar fees for use of water. Significant increases in water rental costs or fees or changes in the way that governments regulate water supply could have a material adverse effect on our financial condition.

The operation of our generation assets is subject to extensive regulation by various government agencies at the municipal, provincial, state and federal level. As legal requirements frequently change and are subject to interpretation and discretion, we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. Any new law or regulation could

require additional expenditure to achieve or maintain compliance. In addition, we may not be able to renew, maintain or obtain all necessary licenses, permits and governmental approvals required for the continued operation or further development of our projects.

Our power generation assets could be exposed to effects of significant events, such as severe weather conditions, natural disasters, major accidents, action of malicious destruction, sabotage or terrorism, which could limit our ability to generate or sell power. In certain cases, some events may not excuse us from performing our obligations pursuant to agreements with third parties and we may be liable for damages or suffer further losses as a result. In addition, many of our generation assets are located in remote areas which makes access for repair of damage difficult.

Timberlands

The financial performance of our timberland operations depends on the state of the wood products and pulp and paper industries. Decreases in the level of residential construction activity generally reduce demand for logs and wood products, resulting in lower revenues, profits and cash flows for our customers. Depressed prices for wood products, pulp or paper or market irregularities may cause mill operators to temporarily or permanently shut down their mills if their product prices fall to a level where mill operation would be uneconomic. Any of these circumstances could significantly reduce the prices that we realize for our timber and the amount of timber that such operators purchase from us.

Weather conditions, timber growth cycles, access limitations, aboriginal claims and regulatory requirements associated with forestry practices, sale of logs and environmental matters, may restrict our harvesting, as may other factors, including damage by fire, insect infestation, disease, prolonged drought and other natural and man-made disasters. Although management believes it follows best practices with regard to forest sustainability and general forest management, there can be no assurance that our forest management planning, including silviculture, will have the intended result of ensuring that our asset base appreciates in value over time. If management's estimates of merchantable inventory are incorrect, harvesting levels on our timberlands may result in depletion of our timber assets.

Transmission Infrastructure

Our transmission operations are subject to regulation. The regulated rates are designed to recover allowed costs, including debt financing costs, and permit earning a specified rate of return on assets or equity. Any changes in the rate structure for the transmission assets or any reallocation or redetermination of allowed costs relating to the transmission assets, could have a material adverse effect on our transmission revenues and operating margins.

Residential Properties

We have residential land development and homebuilding operations located in the United States of America, Canada, Brazil and Australia. These operations are concentrated in areas which we believe have positive long-term demographic and economic characteristics. Despite this, 2008 was another challenging year for the U.S. housing industry, as the downturn in the housing market intensified, further adversely affecting our operations.

The residential homebuilding and land development industry is cyclical and is significantly affected by changes in general and local economic and industry conditions, such as consumer confidence, employment levels, availability of financing for homebuyers and interest rates, levels of new and existing homes for sale, demographic trends and housing demand. Competition from rental properties and resale homes, including homes held for sale by investors and foreclosed homes, may reduce our ability to sell new homes, depress prices and reduce margins for the sale of new homes. Homebuilders are also subject to risks related to the availability and cost overruns. Furthermore, the market value of undeveloped land, buildable lots and housing inventories held by us can fluctuate significantly as a result of changing economic and real estate market conditions. If there are significant adverse changes in economic or real estate market conditions, we may have to sell homes at a loss or hold land in inventory longer than planned. Inventory carrying costs can be significant and can result in losses in a poorly performing project or market. Our residential property operations may be particularly affected by changes in local market conditions in California, Virginia, Alberta and Brazil where we derive a large proportion of our residential property revenue. During 2008, we recorded approximately \$153 million of charges against our U.S. revenues to reflect changing conditions.

Virtually all of our customers finance their home acquisitions through lenders providing mortgage financing. Mortgage rates have recently been at or near their lowest levels in many years. Despite this, and given the dramatic issues being experienced in the mortgage markets in the U.S. and by many lenders, fewer loan products and tighter loan qualification requirements have made it more difficult for borrowers to procure mortgages.

Even if potential customers do not need financing, changes in interest rates and mortgage availability could make it harder for them to sell their homes to potential buyers who need financing, which in the U.S. has resulted in reduced demand for new homes. As a result, rising mortgage rates could adversely affect our ability to sell new homes and the price at which we can sell them.

Specialty Investment Funds

Our specialty funds operations are focused on the ownership and management of securities and businesses that are supported by underlying tangible assets and cash flows. The principal risks in this business are potential loss of invested capital as well as insufficient investment or fee income to cover operating expenses and cost of capital.

Unfavourable economic conditions could have a significant impact on the value and liquidity of our investments and the level of investment income. Since most of our investments are in our areas of expertise and given that we strive to maintain adequate supplemental liquidity at all times, we are well positioned to assume ownership of and operate most of the assets and businesses that we finance. Furthermore, if this situation does arise, we typically acquire the assets at a discount to the underwritten value, which protects us from loss.

Other Risks

As an owner and manager of real property, we are subject to various federal, provincial, state and municipal laws relating to environmental matters. These laws could hold us liable for the costs of removal and remediation of certain hazardous substances or wastes released or deposited on or in our properties or disposed of at other locations. The failure to remove or remediate such substances, if any, could adversely affect our ability to sell our real estate or to borrow using real estate as collateral, and could potentially result in claims or other proceedings against us. We are not aware of any material non-compliance with environmental laws at any of our properties. We are also not aware of any material pending or threatened investigations or actions by environmental regulatory authorities in connection with any of our properties or any material investigations or actions by environmental regulatory authorities in connection with any of our properties or any material pending threatened claims relating to environmental conditions at our properties. We have made and will continue to make the necessary capital expenditures for compliance with environmental laws and regulations. Environmental laws and regulations can change rapidly and we may become subject to more stringent environmental laws and regulations in the future. Compliance with more stringent environmental laws and regulations could have an adverse effect on our business, financial condition or results of operation.

The ownership and operation of our assets carry varying degrees of inherent risk of liability related to worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to contravention of health, safety and environmental laws, licenses, permits and other approvals, and potential civil liability. Compliance with health, safety and environmental laws (and any future laws or amendments enacted) and the requirements of licenses, permits and other approvals will remain material to our business. We have incurred and will continue to incur significant capital and operating expenditures to comply with health, safety and environmental laws and to obtain and comply with licenses, permits and other approvals and to assess and manage potential liability exposure. Nevertheless, from time to time it is possible that we may be unsuccessful in obtaining an important license, permit or other approval or become subject to government orders, investigations, inquiries or other proceedings (including civil claims) relating to health, safety and environmental matters. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licenses, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures. As a consequence, no assurance can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to our business and operations.

We carry various insurance coverages that provide comprehensive protection for first-party and third-party losses to our properties. These coverages contain policy specifications, limits and deductibles customarily carried for similar properties. We also self-insure a portion of certain of these risks. We believe all of our properties are adequately insured.

There are certain types of risks (generally of a catastrophic nature such as war or environmental contamination such as toxic mold) which are either uninsurable or not economically insurable. Should any uninsured or underinsured loss occur, we could lose our investment in, and anticipated profits and cash flows from, one or more of our assets or operations, and would continue to be obligated to repay any recourse mortgage indebtedness on such properties.

In the normal course of our operations, we become involved in various legal actions, including claims relating to personal injuries, property damage, property taxes, land rights and contract and other commercial disputes. We endeavour to maintain adequate provisions for outstanding or pending claims. The final outcome with respect to outstanding, pending or future actions cannot be predicted with certainty, and therefore there can be no assurance that their resolution will not have an adverse effect on our financial position or results of our operations in a particular quarter or fiscal year. We believe that we are not currently involved in any litigation, claims or proceedings in which an adverse outcome would have a material adverse effect on our consolidated financial position or results.

Ongoing changes to the physical climate in which we operate may have an impact on our business. In particular, changes in weather patterns may impact hydrology levels thereby influencing generation levels and power generation levels. Climate change may also give rise to changes in regulations and consumer sentiment that could impact other areas of our business.

The U.S. Investment Company Act of 1940 (the “Act”) requires the registration of any company which holds itself out to the public as being engaged primarily in the business of investing, reinvesting or trading in securities. In addition, the Act may also require the registration of a company that is engaged or proposes to engage in the business of investing, reinvesting, owning, holding or trading in securities and which owns or proposes to acquire investment securities with a value of more than 40% of the company’s assets on an unconsolidated basis. We are not currently an investment company in accordance with the Act and we believe we can continue to arrange our business operations in ways so as to avoid becoming an investment company within the meaning of the Act. If we were required to register as an investment company under the Act, we would, among other things, be restricted from engaging in certain businesses and issuing certain securities. In addition, certain of our contracts may become void.

There are many other laws and governmental regulations that apply to us, our assets and businesses. Changes in these laws and governmental regulations, or their interpretation by agencies or the courts, could occur. Further, economic and political factors, including civil unrest, governmental changes and restrictions on the ability to transfer capital across borders in the United States, but primarily in the foreign countries in which we have invested, can have a major impact on us as a global company.

A portion of the workforce in our operations is unionized and if we are unable to negotiate acceptable contracts with any of our unions as existing agreements expire, we could experience a significant disruption of the affected operations, higher ongoing labour costs and restriction of its ability to maximize the efficiency of its operations, which could have an adverse effect on our operations and financial results.

PART 6 – INTERNATIONAL FINANCIAL REPORTING STANDARDS

International Financial Reporting Standards

The Accounting Standards Board (“AcSB”) confirmed in February 2008 that International Financial Reporting Standards (“IFRS”) will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on and after January 1, 2011. We applied to the Canadian Securities Administrators (“CSA”) and were granted exemptive relief to prepare our financial statements in accordance with IFRS earlier and intend to do so for periods beginning January 1, 2010 and prepare our first financial statements in accordance with IFRS for the three month period ended March 31, 2010. These financial statements will include comparative results for the periods commencing January 1, 2009.

The following discussion has been prepared on a basis consistent with the presentation under Canadian GAAP. The classification and components of account balances under IFRS are expected to be different than under Canadian GAAP. Additionally, as we continue to assess the impact of our transition to IFRS, additional differences may be identified which could impact the above amounts.

Impact of Adoption of IFRS

IFRS are premised on a conceptual framework similar to Canadian GAAP, however, significant differences exist in certain matters of recognition, measurement and disclosure. While we believe that the adoption of IFRS will not have a material impact on our reported cash flows, it will likely have a material impact on our consolidated balance sheets and statements of income. In particular, our opening balance sheet will reflect the revaluation of substantially all property, plant and equipment to fair value, irrespective of the accounting treatment on a prospective basis. In addition, a significant portion of our intangible assets and liabilities will no longer be recognized. Finally, all changes to the opening balance sheet will require that a corresponding tax asset or liability be established based on the resultant differences between the carried value of assets and liabilities and their associated tax bases. Our initial estimate of the impact of all of these differences to common equity totals approximately \$7.0 billion, resulting in common equity to shareholders of \$12.0 billion. The following disclosure highlights the initial adjustments required to be made on adoption of IFRS in order to provide an opening balance sheet and the significant accounting policies, required or expected to be applied by us subsequent to adoption that will be significantly different from our current accounting policies.

IFRS 1: First-time Adoption of International Financial Reporting Standards

Our adoption of IFRS will require the application of IFRS 1 *First-time Adoption of International Financial Reporting Standards* (“IFRS 1”), which provides guidance for an entity’s initial adoption of IFRS. IFRS 1 generally requires that an entity apply all IFRS effective at the end of its first IFRS reporting period retrospectively. However, IFRS 1 does require certain mandatory exceptions and limited optional exemptions in specified areas of certain standards from this general requirement. The following are the optional exemptions available under IFRS 1 significant to us that we expect to apply in preparing our first financial statements under IFRS.

Fair value of revaluation as deemed cost

IFRS 1 allows an entity to initially measure an item of property, plant and equipment upon transition to IFRS at fair value or under certain circumstances using a previous GAAP revaluation, as opposed to recreating depreciated cost under IFRS. We will for items of property, plant and equipment use either fair value or a previous GAAP revaluation as deemed cost. We expect to use fair value as a measure of deemed cost for a significant portion of our property, plant and equipment, the cumulative effect of which is expected to result in higher carrying values under IFRS compared to those under Canadian GAAP. This increase in carrying value is primarily the result of the accounting depreciation taken under Canadian GAAP no longer attributed to the assets at transition, in addition to the value appreciation of such assets in aggregate since acquisition.

Business combinations

IFRS 1 allows for the guidance under IFRS 3R *Business Combinations* (“IFRS 3R”) to be applied either retrospectively or prospectively. Retrospective application would require that we restate all business combinations occurring before the date of our transition to IFRS which is January 1, 2009. We expect to adopt IFRS 3R prospectively. Accordingly, all business combinations on or after January 1, 2009 would be accounted for in accordance with IFRS 3R.

Cumulative translation differences

IAS 21 *The Effects of Changes in Foreign Exchange Rates* requires an entity to determine the translation differences in accordance with IFRS from the date on which a subsidiary was formed or acquired. IFRS allows cumulative translation differences for all foreign operations to be deemed zero at the date of transition to IFRS, with future gains or losses on subsequent disposal of any foreign operations to exclude translation differences arising from periods prior to the date of transition to IFRS. We expect to deem all cumulative translation differences to be zero on transition to IFRS.

IFRS 1 allows for certain other optional exemptions; however, we do not expect such exemptions to be significant to our adoption of IFRS.

Impact of IFRS 1 on the Balance Sheet

The following paragraphs quantify and describe the expected impact of significant differences between our December 31, 2008 balance sheet under Canadian GAAP and our January 1, 2009 opening balance sheet under IFRS. This discussion has been prepared using the standards and interpretations currently issued and expected to be effective at the end of our first annual IFRS reporting period, which we intend to be December 31, 2010. Certain accounting policies expected to be adopted under IFRS may not be adopted and the application of such policies to certain transactions or circumstances may be modified and as a result the pro-forma January 1, 2009 underlying values prepared on a basis consistent with IFRS are subject to change. The amounts have not been audited or subject to review by our external auditor.

Property, Plant and Equipment

We expect the book value of our property, plant and equipment at January 1, 2009 to increase by approximately \$9.7 billion under IFRS compared to the book value as prepared in accordance with Canadian GAAP. This increase is primarily related to recording the majority of property, plant and equipment at fair value for purposes of establishing deemed cost under IFRS. The following describes the impact of this change on the major components of our property, plant and equipment.

Commercial Property

Our commercial properties are considered investment properties under IAS 40, *Investment Property* ("IAS 40"). Investment property includes land and buildings held primarily to earn rental income or for capital appreciation or both, rather than for use in the production or supply of goods or for sale in the ordinary course of business. Similar to Canadian GAAP, investment property is initially measured at cost under IAS 40. However, subsequent to initial recognition, IFRS requires that an entity choose either the cost or fair value model to account for its investment property. We will determine our policy upon adoption. At December 31, 2008, we initially determined the deemed cost of our commercial property portfolio to be approximately \$3.6 billion greater than the carrying value under Canadian GAAP, net of intangible assets and straight-line rent recorded under Canadian GAAP. We determined the fair value of each investment property based upon, among other things, rental income from current leases and assumptions about rental income from future leases reflecting current conditions less future cash outflows in respect of such leases. Fair values were primarily determined by discounting the expected future cash flows, generally over a term of 10 years and using weighted average discount and terminal capitalization rates of 8.2% and 7.1%, respectively.

Power Generating Stations

We have chosen to measure certain property, plant and equipment of our power generation business at fair value for purposes of establishing deemed cost as opposed to recreating depreciated cost using IFRS principles since inception. At December 31, 2008, we initially determined the fair value of our power generation assets to be approximately \$5.1 billion greater than their carrying value under Canadian GAAP. These valuations were generally completed by discounting the expected future cash flows of each station over a 20 year term and using a weighted average discount and terminal capitalization rate of 11.5%.

Timberlands

Under IFRS our timberlands are considered biological assets, recorded under IAS 41 *Agriculture* ("IAS 41") are carried at fair value, less estimated point-of-sale costs. Fair value has been determined as the future expected market price for similar species and age of timberlands less costs to sell, discounted to the measurement date. At December 31, 2008, we have initially determined the fair value of our timberland assets to be approximately \$0.8 billion greater than their carrying value under Canadian GAAP, net of Canadian GAAP depletion. Key assumptions include a weighted average discount and terminal capitalization rate of 6.5% at a terminal valuation date of 72 years on average.

Transmission

For purposes of establishing deemed cost, we have chosen to use the fair value of its transmission assets as opposed to recreating depreciated cost under IFRS. At December 31, 2008, we had initially determined the fair value of our transmission assets to be approximately equal to their carrying value under Canadian GAAP.

Development Properties and Residential Inventory

Inventories are carried at the lower of cost or net realizable value under both IFRS and Canadian GAAP. Under IFRS, however, net realizable value is determined based on the discounted value of future cash flows whereas under Canadian GAAP such cash flows are not discounted. Accordingly, this difference results in a lower determination of net realizable value under IFRS than Canadian GAAP. Brookfield has assessed net realizable value for purposes of IFRS, generally using discount rates between 12% and 15%. The net realizable value of most residential inventory was greater than cost, however this excess value was not reflected in the IFRS carrying value. In certain cases, net realizable value, when determined on a discounted basis, was lower than cost resulting in a \$0.1 billion reduction in carrying value under IFRS when compared to the non-discounted basis under Canadian GAAP.

Other Property, Plant and Equipment

Additional differences also relate to the deconsolidation of certain property, plant and equipment related to entities that are consolidated or proportionately consolidated under Canadian GAAP that are equity accounted under IFRS. This decrease in property, plant and equipment is offset by increases in the carried value of certain property, plant and equipment of investee companies initially recorded at fair value, for purposes of establishing deemed cost, in addition to other adjustments. In aggregate these differences increase property, plant and equipment by an additional \$0.4 billion.

Investments

We expect investments at January 1, 2009 to increase by approximately \$1.6 billion under IFRS than as prepared in accordance with Canadian GAAP. The increase primarily relates to entities that are consolidated or proportionately consolidated under Canadian GAAP that will be equity accounted under IFRS and accordingly included in the investments account. The impact to net equity as a result of corresponding minority interest after deferred taxes is \$0.6 billion primarily related to initially measuring, for purposes of IFRS, the property, plant and equipment of such entities at fair value to establish an initial carrying value.

Securities

We expect securities at January 1, 2009 to increase by approximately \$0.3 billion under IFRS than as prepared in accordance with Canadian GAAP. This increase primarily relates to securities held by us that are not traded in an active market but for which fair value can be reliably determined. Under Canadian GAAP these securities are held at cost whereas under IFRS these securities are measured at fair value.

Accounts Receivable, Other and Intangible Assets and Liabilities

We expect accounts receivable, other and intangible assets and liabilities at January 1, 2009 to decrease on a net basis by approximately \$1.1 billion under IFRS than as prepared in accordance with Canadian GAAP. This decrease primarily relates to the deconsolidation of assets held by entities that are consolidated or proportionately consolidated under Canadian GAAP that will be equity accounted under IFRS and the removal of certain assets otherwise included in the fair value of commercial properties, such as straight-line rent receivables and above-market leases that are separately accounted for under Canadian GAAP but are reflected as part of the fair value of investment property for IFRS.

Accounts Payable and Other Liabilities

We expect accounts payable and other liabilities at January 1, 2009 to increase by approximately \$3.3 billion under IFRS than as prepared in accordance with Canadian GAAP. This change primarily relates to a \$2.8 billion increase in future income tax liabilities associated with the increased carrying values of assets within our commercial property, power generation and transmission businesses. These items are offset by the removal of liabilities in respect of below market leases related to our commercial properties and the deconsolidation of certain liabilities of entities consolidated or proportionately consolidated under Canadian GAAP that will be equity accounted under IFRS in addition to other adjustments.

Corporate Borrowings, Property Specific Mortgages, Subsidiary Borrowings, and Capital Securities

We expect property specific mortgages and subsidiary borrowings at January 1, 2009 to decrease by approximately \$1.0 billion under IFRS than as prepared in accordance with Canadian GAAP. The decrease primarily relates to the deconsolidation of debt held by entities that are consolidated or proportionately consolidated under Canadian GAAP that will be equity accounted under IFRS. We have not yet determined whether or not we will measure any of these liabilities at fair value.

Goodwill

We expect goodwill at January 1, 2009 to decrease by approximately \$0.1 billion under IFRS than as prepared in accordance with Canadian GAAP. This decrease primarily relates to the allocation of goodwill previously recorded on acquisition of investment properties that under IFRS are recorded at fair value. As the investment properties to which goodwill relates are carried at fair value, goodwill is reduced accordingly under IFRS.

Non-controlling Interests

We expect non-controlling interests at January 1, 2009 to increase by approximately \$1.4 billion under IFRS than as prepared in accordance with Canadian GAAP. The change in minority interests is primarily related to the recognition of others' interests in the increased asset values offset by deconsolidation of certain entities.

Ongoing IFRS to Canadian GAAP differences – Balance Sheet

Basis of Consolidation

Under Canadian GAAP we determine whether we should consolidate an entity using two different frameworks: the variable interest entity ("VIE") and voting control models. Under IFRS we will consolidate an entity if it is determined to be controlled by us. Control is defined as the power to govern the financial and operating policies of an entity to obtain benefit. Control is presumed to exist when the parent owns, directly or indirectly through subsidiaries, more than one half of an entity's voting power, but also exists when the parent owns half or less of the voting power but has legal or contractual rights to control, or de facto control. This change in policy will result in certain entities being consolidated by us that were not consolidated under Canadian GAAP as a result of our legal or contractual rights to control the entity, as defined by IFRS. This change will also result in certain entities that are currently consolidated by us under the VIE model to be deconsolidated.

Joint Ventures

The International Accounting Standards Board ("IASB") is currently considering Exposure Draft 9 *Joint Arrangements* ("ED 9") which is intended to modify IAS 31 *Interests in Joint Ventures* ("IAS 31") which sets out the current requirements for the accounting for interests in joint ventures under IFRS. The IASB has indicated that it expects to issue a new standard to replace IAS 31 in early 2009 and we expect to apply this new standard in its IFRS financial statements for 2010. Currently, under Canadian GAAP we proportionately account for interests in joint ventures. ED 9 proposes to eliminate the option to proportionately consolidate interests in jointly controlled entities and requires an entity to recognize its interest, which is considered its share of the outcome generated by the activities of a group of assets and liabilities subject to joint control, using the equity method.

Biological Assets

Under IFRS timberlands are considered biological assets and recorded under IAS 41. Currently under Canadian GAAP our timberland assets are recorded at cost, less accumulated depletion which is based upon harvested amounts. Depletion amounts are recorded in cost of goods sold at the time of sale. Under IAS 41 timberland assets will be measured at the end of each reporting period at fair value, less estimated point-of-sale costs. Fair value is determined based upon the future expected market price for similar species and age of timberlands less costs to sell, discounted to the measurement date. Changes in fair value or point-of-sale costs after initial recognition are recognized in income in the period in which the change arises.

Inventory

For both Canadian GAAP and IFRS, residential inventory is recorded at the lower of cost and net realizable value, however, under IFRS net realizable value is determined based on the discounted value of future cash flows whereas under Canadian GAAP such cash flows are not discounted.

Ongoing IFRS to Canadian GAAP differences – Income Statement

Commercial Property

IFRS permits the measurement of investment property using the fair value model under IAS 40, which requires us to record a gain or loss in income arising from a change in the fair value of investment property in the period of change. Income related to commercial properties may be greater or less than as determined under Canadian GAAP depending on whether an increase or decrease in fair value occurs during the period of measurement. Furthermore, if we were to choose, upon adoption, the fair value model for investment property no depreciation would be recognized. Accordingly, net income would be greater under IFRS than as determined under Canadian GAAP, to the extent there is no change in fair value of the underlying property, as no depreciation will be recorded. Upon recognition of commercial property at fair value for IFRS, all intangible assets and liabilities recorded under Canadian GAAP related to previous business combinations will be de-recognized and will no longer be amortized into income. In 2008 under Canadian GAAP approximately \$0.8 billion is charged to income annually in respect of depreciation and amortization of intangible assets, prior to minority interests, related to our commercial property portfolio.

Use of Deemed Cost

We have chosen to initially measure certain property, plant and equipment upon transition to IFRS at fair value or under certain circumstances using a previous GAAP revaluation, as opposed to recreating depreciated cost under IFRS. In most cases the resulting carrying value under IFRS will be higher than the carrying value under Canadian GAAP. As a result, the amount of depreciation recorded under IFRS related to such assets will be greater than what would be charged to income under Canadian GAAP. We expect annual depreciation to be approximately \$0.2 billion greater under IFRS than Canadian GAAP in aggregate for all property, plant and equipment other than our commercial property portfolio.

Timberlands

As described above under IFRS, our timberlands are considered biological assets and recorded under IAS 41. At each reporting period our timberland assets will be measured at fair value, less estimated point-of-sale costs with changes in fair value recognized in income in the period in which the change arises. Certain expenditures capitalized under Canadian GAAP, such as silviculture and other conservation costs, will be expensed under IFRS. These amounts are approximately \$0.1 billion annually. Depending on the change in fair value of timberland assets during each reporting period, income could either be greater or less than under Canadian GAAP.

PART 7 – SUPPLEMENTAL INFORMATION

This section contains information required by applicable continuous disclosure guidelines and to facilitate additional analysis.

CONTRACTUAL OBLIGATIONS

The following table presents the contractual obligations of the company by payment periods:

AS AT DECEMBER 31, 2008 (MILLIONS)	Total	Payments Due by Period			
		Less than One Year	2 – 3 Years	4 – 5 Years	After 5 Years
Long-term debt					
Property-specific mortgages	\$ 22,889	\$ 2,424	\$ 8,130	\$ 3,779	\$ 8,556
Other debt of subsidiaries	5,102	1,423	1,326	1,117	1,236
Corporate borrowings	2,284	—	284	1,065	935
Capital securities	1,425	—	164	574	687
Lease obligations	28	5	11	7	5
Commitments	1,269	1,269	—	—	—
Interest expense ¹					
Long-term debt	6,537	1,633	2,528	1,604	772
Capital securities	480	89	168	123	100
Interest rate swaps	618	256	263	52	47

¹ Represents aggregate interest expense expected to be paid over the term of the obligations. Variable interest rate payments have been calculated based on current rates

Commitments of \$1,269 million (2007 – \$1,068 million) represent various contractual obligations of the company and its subsidiaries assumed in the normal course of business, including commitments to provide bridge financing, and letters of credit and guarantees provided in respect of power sales contracts and reinsurance obligations, of which \$211 million (2007 – \$95 million) is included as liabilities in the consolidated balance sheets.

OFF BALANCE SHEET ARRANGEMENTS

We conduct our operations primarily through entities that are fully or proportionately consolidated in our financial statements. We do hold non-controlling interests in entities which are accounted for on an equity basis, as are interests in some of our funds, however we do not guarantee any financial obligations of these entities other than our contractual commitments to provide capital to a fund, which are limited to predetermined amounts.

We utilize various financial instruments in our business to manage risk and make better use of our capital. The fair values of these instruments that are reflected on our balance sheets, are disclosed in Note 18 to our Consolidated Financial Statements and under Financial and Liquidity Risks beginning on page 60.

RELATED-PARTY TRANSACTIONS

In the normal course of operations, the company enters into various transactions on market terms with related parties, which have been measured at exchange value and are recognized in the consolidated financial statements. There were no such transactions, individually or in aggregate, that were material to our overall operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to select appropriate accounting policies to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. In particular, critical accounting policies and estimates utilized in the normal course of preparing the company's financial statements require the determination of future cash flows utilized in assessing net recoverable amounts and net realizable values; depreciation and amortization; value of goodwill and intangible assets; ability to utilize tax losses; the determination of the primary beneficiary of variable interest entities; effectiveness of financial hedges for accounting purposes; and fair values for recognition, measurement and disclosure purposes.

In making estimates, management relies on external information and observable conditions where possible, supplemented by internal analysis as required. These estimates have been applied in a manner consistent with that in the prior year and there are no

known trends, commitments, events or uncertainties that we believe will materially affect the methodology or assumptions utilized in this report. The estimates are impacted by, among other things, movements in interest rates and other factors, some of which are highly uncertain, as described in the analysis of Business Strategy, Environment and Risks beginning on page 56 and in the section entitled Financial and Liquidity Risk beginning on page 60. The interrelated nature of these factors prevents us from quantifying the overall impact of these movements on the company's financial statements in a meaningful way. For further reference on critical accounting policies, see our significant accounting policies contained in Note 1 and Changes in Accounting Policies as described below.

CHANGES IN ACCOUNTING POLICIES

Financial Instruments – Disclosures and Presentation

On December 1, 2006, the Canadian Institute of Chartered Accountants ("CICA") issued two new accounting standards, Section 3862, *Financial Instruments – Disclosures* and Section 3863, *Financial Instruments – Presentation*. These standards replace Section 3861, *Financial Instruments – Disclosure and Presentation* and enhance the disclosure of the nature and extent of risks arising from financial instruments and how the entity manages those risks. These new standards became effective for the company on January 1, 2008 and the related disclosure is included as Note 1 to the consolidated financial statements in this report.

Capital Disclosures

On December 1, 2006, the CICA issued Section 1535, *Capital Disclosures*. Section 1535 requires the disclosure of: (i) an entity's objectives, policies and process for managing capital; (ii) quantitative data about an entity's managed capital; (iii) whether an entity has complied with capital requirements; and (iv) if an entity has not complied with such capital requirements, the consequences of such non-compliance. This new standard became effective for the company on January 1, 2008 and the related disclosure is included as Note 20 to the consolidated financial statements in this report.

Inventories

In June 2007, the CICA issued Section 3031, *Inventories*, replacing Section 3030, *Inventories*. This standard provides guidance on the determination of the cost of inventories and the subsequent recognition as an expense, including any write-down to net realizable value. This new standard became effective for the company on January 1, 2008. The impact of adopting this new standard was a \$4 million reduction of opening retained earnings.

FUTURE CHANGES IN ACCOUNTING POLICIES

Goodwill and Intangible Assets

In February 2008, the CICA issued Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Handbook Sections 3062, *Goodwill and Other Intangible Assets* and 3450, *Research and Development Costs*. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to the financial statements relating to fiscal years beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition of intangible assets by profit-oriented enterprises. The company is currently evaluating the impact of Section 3064 on its financial statements.

International Financial Reporting Standards

The AcSB confirmed in February 2008 that IFRS will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on and after January 1, 2011. The company applied to the CSA and was granted exemptive relief to prepare its financial statements in accordance with IFRS earlier than required and intends to do so for periods beginning January 1, 2010, preparing its first financial statements in accordance with IFRS for the three month period ended March 31, 2010. These financial statements will include comparative results for the periods commencing January 1, 2009.

ASSESSMENT AND CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

Management has evaluated the effectiveness of the company's internal control over financial reporting. Refer to Management's Report on Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting during the year ended December 31, 2008 that have materially affected, or are reasonably likely to materially affect the internal control over financial reporting.

DISCLOSURE CONTROLS

Management, including the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as defined in the Canadian Securities Administrators National Instrument 52-109). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that such disclosure controls and procedures were effective as of December 31, 2008 in providing reasonable assurance that material information relating to the company and the consolidated subsidiaries would be made known to them within those entities.

CORPORATE DIVIDENDS

The distributions paid by Brookfield on outstanding securities during the past three years are as follows:

	<i>Distribution per Security</i>		
	<i>2008</i>	<i>2007</i>	<i>2006</i>
Class A Common Shares	\$ 0.51	\$ 0.47	\$ 0.40
Class A Common Shares – special ¹	0.94	—	—
Class A Preferred Shares			
Series 2	0.83	0.99	0.88
Series 4 + Series 7	0.83	0.99	0.88
Series 8	1.18	1.10	1.10
Series 9	1.02	1.01	1.25
Series 10	1.35	1.34	1.27
Series 11	1.29	1.28	1.22
Series 12	1.27	1.26	1.19
Series 13	0.83	0.99	0.88
Series 14	3.06	3.57	3.10
Series 15	0.99	1.15	1.00
Series 17 ²	1.12	1.11	0.12
Series 18 ³	1.12	0.71	—
Series 21 ⁴	0.58	—	—
Preferred Securities			
Due 2050 ⁵	—	0.01	1.85
Due 2051 ⁶	—	0.95	1.84

¹ Represents the book value of Brookfield Infrastructure special dividend

² Issued November 20, 2006

³ Issued May 9, 2007

⁴ Issued June 25, 2008

⁵ Redeemed January 2, 2007

⁶ Redeemed July 3, 2007

QUARTERLY RESULTS

Net income and operating cash flows for the eight recently completed quarters are as follows:

(MILLIONS)	2008				2007			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total revenues	\$ 3,006	\$ 3,216	\$ 3,436	\$ 3,210	\$ 3,158	\$ 2,219	\$ 2,125	\$ 1,841
Fees earned	113	109	113	114	92	96	95	132
Revenues less direct operating costs								
Commercial property	388	595	427	421	414	350	396	388
Power generation	158	213	264	251	148	105	170	188
Infrastructure	68	36	44	48	33	54	114	89
Development and other properties	(5)	62	119	64	115	40	117	146
Specialty funds	49	32	119	104	233	16	59	62
Investment and other income	207	242	142	312	337	248	143	129
	978	1,289	1,228	1,314	1,372	909	1,094	1,134
Expenses								
Interest	447	535	475	527	510	454	424	398
Asset management and other operating costs	160	167	148	165	141	108	105	110
Current income taxes	(47)	2	21	17	28	(6)	26	20
Non-controlling interest in net income before the following	176	235	212	168	124	103	204	205
Net income before the following	242	350	372	437	569	250	335	401
Equity accounted income (loss) from investments	(12)	(6)	(15)	(13)	(4)	—	(29)	(39)
Depreciation and amortization	(355)	(333)	(328)	(314)	(294)	(250)	(267)	(223)
Revaluation and other items	(262)	104	(46)	(63)	(95)	(33)	11	5
Future income taxes	545	(105)	3	18	35	11	(69)	(65)
Non-controlling interests in the foregoing items	13	161	124	132	135	115	172	116
Net income	\$ 171	\$ 171	\$ 110	\$ 197	\$ 346	\$ 93	\$ 153	\$ 195

Cash flow from operations for the last eight quarters are as follows:

(MILLIONS, EXCEPT PER SHARE AMOUNTS)	2008				2007			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Net income before the following	\$ 242	\$ 350	\$ 372	\$ 437	\$ 569	\$ 250	\$ 335	\$ 401
Dividends from equity accounted investments	5	5	6	6	6	5	5	5
Exchangeable debenture gain	—	—	—	—	—	66	100	165
Cash flow from operations and gains	247	355	378	443	575	321	440	571
Preferred share dividends	9	11	12	12	12	13	10	9
Cash flow to common shareholders	\$ 238	\$ 344	\$ 366	\$ 431	\$ 563	\$ 308	\$ 430	\$ 562
Common equity – book value	\$ 4,918	\$ 5,821	\$ 6,284	\$ 6,140	\$ 6,644	\$ 6,328	\$ 6,337	\$ 6,061
Common shares outstanding ¹	572.6	583.4	583.8	581.7	583.6	581.0	583.6	582.2
Per common share ¹								
Cash flow from operations	\$ 0.41	\$ 0.58	\$ 0.62	\$ 0.72	\$ 0.94	\$ 0.52	\$ 0.72	\$ 0.93
Net income	0.27	0.27	0.17	0.31	0.56	0.13	0.24	0.31
Dividends	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.11
Book value	8.93	10.22	11.15	10.95	11.64	11.17	11.07	10.59
Market trading price (NYSE)	15.27	27.44	32.54	26.83	35.67	38.50	39.90	34.84

¹ Adjusted to reflect three-for-two stock split

For the three months ended December 31, 2008, we reported net income of \$171 million and \$346 million for the same period in 2007. Operating cash flow was \$247 million for the fourth quarter of 2008, compared to \$575 million during the same period in 2007 as shown in the table on the following page. The results for the three months ended December 31, 2007 included a large number of major disposition gains compared with the fourth quarter of 2008.

Commercial office property operations tend to produce consistent results throughout the year due to the long-term nature of the contractual lease arrangements subject to the intermittent recognition of disposition gains. Quarterly seasonality does exist in our power generation and residential property operations. With respect to our power generation operations, seasonality exists in water inflows and pricing. During the fall rainy season and spring thaw, water inflows tend to be the highest leading to higher generation during those periods; however prices tend not to be as strong as the summer and winter seasons due to the more moderate weather

conditions during those periods and associated reductions in demand for electricity. With respect to our residential operations, the fourth quarter tends to be the strongest as this is the period during which most of the construction is completed and homes are delivered although in 2007 and 2008 the company has recorded provisions in respect of higher priced land positions. We periodically record realization and other gains, special distributions, as well as gains and losses on unhedged financial positions throughout our operations and, while the timing of these items is difficult to predict, the dynamic nature of our asset base tends to result in these items occurring on a relatively frequent basis.

ADDITIONAL SHARE DATA

Basic and Diluted Earnings Per Share

The components of basic and diluted earnings per share are summarized in the following table:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007
Net income	\$ 649	\$ 787
Preferred share dividends	(44)	(44)
Net income available for common shareholders	\$ 605	\$ 743
Weighted average – common shares	581	582
Dilutive effect of the conversion of options using treasury stock method	11	17
Common shares and common share equivalents	592	599

Issued and Outstanding Common Shares

The number of issued and outstanding common shares changed as follows:

FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008	2007
Outstanding at beginning of year	583.6	581.8
Issued (repurchased)		
Dividend reinvestment plan	0.2	0.1
Management share option plan	3.0	4.9
Issuer bid purchases	(14.2)	(5.0)
Acquisition	—	1.8
Outstanding at end of year	572.6	583.6
Unexercised options	27.7	27.4
Total diluted common shares at end of year	600.3	611.0

In calculating our book value per common share, the cash value of our unexercised options of \$446 million (2007 – \$469 million) is added to the book value of our common share equity of \$4,918 million (2007 – \$6,644 million) prior to dividing by the total diluted common shares presented above.

As of March 13, 2009, the Corporation had outstanding 571,687,632 Class A Limited Voting Shares and 85,120 Class B Limited Voting Shares.

ASSETS UNDER MANAGEMENT

The following tables set forth the assets, net invested capital and commitments managed by Brookfield, including the amounts managed on behalf of co-investors:

		Total Assets Under Management			Co-investor Interests		Brookfield's
	Year		Net Invested	Committed	Net Invested	Committed	Ownership
AS AT DECEMBER 31, 2008 (MILLIONS)	Formed	Assets	Capital	Capital ¹	Capital	Capital	Level
Core and Value Add							
U.S. Core Office ²	2006	\$ 7,662	\$ 1,777	\$ 1,950	\$ 999	\$ 1,025	62%
Canadian Core Office ²	2005	1,320	867	867	545	545	25%
Multiplex Funds ³	2007	1,652	944	944	627	689	various
West Coast Timberlands ⁴	2005	889	496	496	382	382	28%
East Coast Timber Fund	2006	167	87	87	59	59	45%
Global Timber Fund	2008	2,411	825	1,348	593	780	37%
Transmission – Chile ⁴	2006	2,202	1,363	1,363	1,172	1,172	17%
Transmission – Canada/Brazil ⁴	2008	532	244	244	113	113	various
Bridge Loan I	2003	545	545	570	407	409	39%
Bridge Loan II	2007	150	150	773	101	576	25%
Real Estate Finance	various	2,497	1,354	1,892	1,212	1,487	4-51%
Brookfield Real Estate Services Fund	2003	140	84	84	63	63	25%
		20,167	8,736	10,618	6,273	7,300	
Opportunity and Private Equity							
Real Estate Opportunity	2006	913	201	227	105	105	52%
Real Estate Opportunity II	2007	382	109	208	48	83	60%
Brazil Retail Property	2006	1,326	438	830	348	610	25%
Brazil Timber Fund	2008	—	—	280	—	230	—
Residential Properties – U.S. ⁵	2007	978	383	383	200	200	29%
Tricap Restructuring I	2002	733	295	295	150	150	48%
Tricap Restructuring II	2006/7	892	593	881	354	496	39%
		5,224	2,019	3,104	1,205	1,874	
Listed Securities and Fixed Income							
Equity Funds	various	2,962	2,962	2,962	2,962	2,962	3%
Fixed Income Funds	various	15,199	15,078	15,078	15,078	15,078	n/a
		18,161	18,040	18,040	18,040	18,040	
Total fee bearing assets/capital		43,552	28,795	31,762	\$ 25,518	\$ 27,214	n/a
Directly Held Non-Fee Bearing Assets							
Core Office – North America ²		9,335	2,096	2,096			
Core Office – Europe		1,068	368	368			
Core Office – Australia		2,670	1,600	1,600			
Residential Properties – Canada ² /Brazil/Australia		2,842	434	434			
Power Generation – North America		6,473	1,407	1,407			
Timber – Brazil		90	65	65			
Other		12,667	7,103	7,103			
		35,145	13,073	13,073			
		\$ 78,697	\$ 41,868	\$ 44,835			

¹ Includes incremental co-investment capital

² Held by 51%-owned Brookfield Properties

³ Comprised of four funds with ownerships ranging from 20% to 25%

⁴ Represents direct interests plus pro rata share of indirect interests held by 40%-owned Brookfield Infrastructure Partners

⁵ Held by 58%-owned Brookfield Homes

Internal Control Over Financial Reporting

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of Brookfield Asset Management Inc. ("Brookfield") is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and the Chief Financial Officer and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles as defined in Regulation 240.13a-15(f) or 240.15d-15(f).

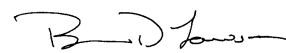
Management assessed the effectiveness of Brookfield's internal control over financial reporting as of December 31, 2008, based on the criteria set forth in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that, as of December 31, 2008, Brookfield's internal control over financial reporting is effective. Management excluded from its assessment the internal control over financial reporting at Norbord Inc. ("Norbord"), which was acquired during 2008, and whose total assets, net assets, total revenues, and net income constitute approximately 2%, 1%, nil% and nil% respectively of the consolidated financial statement amounts as of and for the year ended December 31, 2008.

Management's assessment of the effectiveness of Brookfield's internal control over financial reporting as of December 31, 2008, has been audited by Deloitte & Touche, LLP, Independent Registered Chartered Accountants, who also audited Brookfield's Consolidated Financial Statements for the year ended December 31, 2008. As stated in the Report of Independent Registered Chartered Accountants, Deloitte & Touche, LLP expressed an unqualified opinion on Brookfield's internal control over financial reporting as of December 31, 2008.

Toronto, Canada
March 13, 2009



J. Bruce Flatt
Chief Executive Officer



Brian D. Lawson
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Brookfield Asset Management Inc.

We have audited the internal control over financial reporting of Brookfield Asset Management Inc. and subsidiaries (the "Company") as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in Management's Report on Internal Control over Financial Reporting, management excluded from its assessment the internal control over financial reporting at Norbord Inc. ("Norbord") which was acquired in 2008 and whose financial statements constitute approximately 1% and 2% of net and total assets, respectively, nil% of revenues, and nil% of net income of the consolidated financial statement amounts as of and for the year ended December 31, 2008. Accordingly, our audit did not include the internal control over financial reporting at Norbord. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable

assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2008 of the Company and our report dated March 13, 2009 expressed an unqualified opinion on those financial statements.

Deloitte + Touche LLP

Toronto, Canada
March 13, 2009

Deloitte & Touche, LLP
*Independent Registered Chartered Accountants
Licensed Public Accountants*

Consolidated Financial Statements

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

The accompanying consolidated financial statements and other financial information in this Annual Report have been prepared by the company's management which is responsible for their integrity, consistency, objectivity and reliability. To fulfill this responsibility, the company maintains policies, procedures and systems of internal control to ensure that its reporting practices and accounting and administrative procedures are appropriate to provide a high degree of assurance that relevant and reliable financial information is produced and assets are safeguarded. These controls include the careful selection and training of employees, the establishment of well-defined areas of responsibility and accountability for performance and the communication of policies and code of conduct throughout the company. In addition, the company maintains an internal audit group that conducts periodic audits of all aspects of the company's operations. The Chief Internal Auditor has full access to the Audit Committee.

These consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada, and where appropriate, reflect estimates based on management's judgment. The financial information presented throughout this Annual Report is generally consistent with the information contained in the accompanying consolidated financial statements.

Deloitte & Touche, LLP, the independent registered chartered accountants appointed by the shareholders, have examined the consolidated financial statements set out on pages 80 through 111 in accordance with auditing standards generally accepted in Canada to enable them to express to the shareholders their opinion on the consolidated financial statements. Their report is set out below.

The consolidated financial statements have been further reviewed and approved by the Board of Directors acting through its Audit Committee, which is comprised of directors who are not officers or employees of the company. The Audit Committee, which meets with the auditors and management to review the activities of each and reports to the Board of Directors, oversees management's responsibilities for the financial reporting and internal control systems. The auditors have full and direct access to the Audit Committee and meet periodically with the committee both with and without management present to discuss their audit and related findings.



Toronto, Canada
March 13, 2009

J. Bruce Flatt
Chief Executive Officer

Brian D. Lawson
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Brookfield Asset Management Inc.

We have audited the accompanying consolidated balance sheets of Brookfield Asset Management Inc. and subsidiaries (the "Company") as at December 31, 2008 and 2007, and the related consolidated statements of income, retained earnings, comprehensive (loss) income, accumulated other comprehensive (loss) income and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Oversight Board (United States). These standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2008, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 13, 2009 expressed an unqualified opinion on the Company's internal control over financial reporting.



Toronto, Canada
March 13, 2009

Independent Registered Chartered Accountants
Licensed Public Accountants

CONSOLIDATED BALANCE SHEETS

AS AT DECEMBER 31 (MILLIONS)

	Note	2008	2007
Assets			
Cash and cash equivalents		\$ 1,242	\$ 1,561
Financial assets	3	787	1,529
Investments	4	890	1,352
Accounts receivable and other	5	7,310	7,139
Intangible assets	6	1,632	2,026
Goodwill	2	2,011	1,528
Operating assets			
Property, plant and equipment	7	36,375	37,725
Securities	8	1,303	1,828
Loans and notes receivable	9	2,061	909
		\$ 53,611	\$ 55,597
Liabilities and shareholders' equity			
Corporate borrowings	10	\$ 2,284	\$ 2,048
Non-recourse borrowings			
Property-specific mortgages	11	22,889	21,644
Subsidiary borrowings	11	5,102	7,076
Accounts payable and other liabilities	12	8,903	9,863
Intangible liabilities	13	891	1,112
Capital securities	14	1,425	1,570
Non-controlling interests in net assets	15	6,329	4,770
Shareholders' equity			
Preferred equity	16	870	870
Common equity	17	4,918	6,644
		\$ 53,611	\$ 55,597

On behalf of the Board:



Robert J. Harding, FCA, Director



Marcel R. Coutu, Director

CONSOLIDATED STATEMENTS OF INCOME

YEARS ENDED DECEMBER 31 (MILLIONS, EXCEPT PER SHARE AMOUNTS)

	Note	2008	2007
Total revenues		\$ 12,868	\$ 9,343
Fees earned		449	415
Revenues less direct operating costs	21		
Commercial properties		1,831	1,548
Power generation		886	611
Infrastructure		196	290
Development and other properties		240	418
Specialty funds		304	370
		3,906	3,652
Investment and other income		903	857
		4,809	4,509
Expenses			
Interest		1,984	1,786
Current income taxes	23	(7)	68
Asset management and other operating costs		640	464
Non-controlling interests in net income before the following	22	791	636
		1,401	1,555
Other items			
Equity accounted loss from investments	24	(46)	(72)
Depreciation and amortization		(1,330)	(1,034)
Provisions and other		(267)	(112)
Future income taxes	23	461	(88)
Non-controlling interests in the foregoing items	22	430	538
Net income		\$ 649	\$ 787
Net income per common share	17		
Diluted		\$ 1.02	\$ 1.24
Basic		\$ 1.04	\$ 1.27

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

<i>YEARS ENDED DECEMBER 31 (MILLIONS)</i>	<i>2008</i>	<i>2007</i>
Retained earnings, beginning of year	\$ 4,867	\$ 4,222
Change in accounting policy	(4)	292
Net income	649	787
Preferred equity issue costs	—	(6)
Shareholder distributions – preferred equity	(44)	(44)
– common equity	(843)	(272)
Amount paid in excess of book value of common shares purchased for cancellation	(257)	(112)
	\$ 4,368	\$ 4,867

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

<i>YEARS ENDED DECEMBER 31 (MILLIONS)</i>	<i>Note</i>	<i>2008</i>	<i>2007</i>
Net income		\$ 649	\$ 787
Other comprehensive (loss) income	3		
Foreign currency translation		(780)	410
Available-for-sale securities		(277)	(79)
Derivative instruments designated as cash flow hedges		(45)	(73)
Future income taxes on above items		(113)	44
		(1,215)	302
Comprehensive (loss) income		\$ (566)	\$ 1,089

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

<i>YEARS ENDED DECEMBER 31 (MILLIONS)</i>	<i>2008</i>	<i>2007</i>
Balance, beginning of year	\$ 445	\$ —
Transition adjustment – January 1, 2007	—	143
Other comprehensive (loss) income	(1,215)	302
Balance, end of year	\$ (770)	\$ 445

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEARS ENDED DECEMBER 31 (MILLIONS)

	Note	2008	2007
Operating activities			
Net income		\$ 649	\$ 787
Adjusted for the following non-cash items			
Depreciation and amortization		1,330	1,034
Future income taxes and other provisions		(194)	200
Realization gains		(164)	(231)
Non-controlling interest in non-cash items	22	(430)	(538)
Equity accounted loss and dividends received from investments		68	93
		1,259	1,345
Net change in non-cash working capital balances and other		(279)	1,472
Undistributed non-controlling interests in cash flows		587	467
		1,567	3,284
Financing activities			
Corporate borrowings, net of repayments	27	333	476
Property-specific mortgages, net of issuances	27	(1,022)	2,484
Other debt of subsidiaries, net of issuances	27	(500)	1,824
Capital provided by non-controlling interests		533	268
Capital securities issuance/(redemption)		143	(225)
Corporate preferred equity issuance		—	181
Common shares repurchased, net of issuances	27	(249)	(121)
Common shares of subsidiaries repurchased, net of issuances		(17)	(100)
Shareholder distributions		(342)	(316)
		(1,121)	4,471
Investing activities			
Investment in or sale of operating assets, net			
Commercial properties	27	73	(5,140)
Power generation	27	(529)	(452)
Infrastructure	27	361	(1,330)
Development and other properties	27	(699)	(658)
Securities and loans	27	126	(528)
Financial assets	27	319	636
Investments		(187)	115
Other property, plant and equipment		(229)	(41)
		(765)	(7,398)
Cash and cash equivalents			
(Decrease)/Increase		(319)	357
Balance, beginning of year		1,561	1,204
Balance, end of year		\$ 1,242	\$ 1,561

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with generally accepted accounting principles ("GAAP") as prescribed by the Canadian Institute of Chartered Accountants ("CICA").

(a) Basis of Presentation

All currency amounts are in United States dollars ("U.S. dollars") unless otherwise stated. The consolidated financial statements include the accounts of Brookfield Asset Management Inc. (the "company") and the entities over which it has voting control, as well as Variable Interest Entities ("VIEs") for which the company is considered to be the primary beneficiary.

The company accounts for investments over which it has significant influence using the equity basis. Interests in jointly controlled partnerships and corporate joint ventures are proportionately consolidated. Measurement of investments in which the company does not have a significant influence depends on the financial instrument classification.

Certain prior year amounts have been reclassified to conform to the current year's presentation.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates are required in the determination of cash flows and probabilities in assessing net recoverable amounts and net realizable values, tax and other provisions, hedge effectiveness, and fair values.

(b) Reporting Currency

The U.S. dollar is the functional currency of the company's head office operations and the U.S. dollar is the company's reporting currency.

The accounts of self-sustaining subsidiaries having a functional currency other than the U.S. dollar are translated using the current rate method. Gains or losses on translation are deferred and included in other comprehensive income in the cumulative translation adjustment account. Gains or losses on foreign currency denominated balances and transactions that are designated as hedges of net investments in these subsidiaries are reported in the same manner.

Foreign currency denominated monetary assets and liabilities of the company and integrated subsidiaries are translated at the rate of exchange prevailing at year end and revenues and expenses at average rates during the period. Gains or losses on translation of these items are included in the Consolidated Statements of Income. Gains or losses on transactions which hedge these items are also included in the Consolidated Statements of Income. Gains or losses on translation of foreign currency denominated available-for-sale financial instruments are included in other comprehensive income.

(c) Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, demand deposits and all highly liquid short-term investments with original maturities less than 90 days.

(d) Operating Assets

(i) Commercial Properties

Commercial properties held for investment are carried at cost less accumulated depreciation. Depreciation on buildings is provided during the year on a straight-line basis over the estimated useful lives of the properties to a maximum of 60 years. Depreciation is determined with reference to the carried value, remaining estimated useful life and residual value of each rental property. Tenant improvements and re-leasing costs are deferred and amortized over the lives of the leases to which they relate.

CICA Handbook EIC-140, *Accounting for Operating Leases Acquired in either an Asset Acquisition or a Business Combination* and CICA Handbook EIC-137, *Recognition of Customer Relationships Acquired in a Business Combination* require that when a company acquires real estate in either an asset acquisition or business combination, a portion of the purchase price should be allocated to the in-place leases to reflect the intangible amounts of leasing costs, above or below market tenant and land leases, and tenant relationship values, if any. These intangible costs are amortized over their respective lease terms.

(ii) Power Generation

Power generating facilities are recorded at cost, less accumulated depreciation. Depreciation on power generating facilities and equipment is provided at various rates on a straight-line basis over the estimated service lives of the assets, which are up to 60 years for hydroelectric generation assets.

Power generating facilities under development are recorded at cost, including pre-development expenditures, unless impairment is identified requiring a write-down to estimated fair value.

(iii) Infrastructure

(a) Timberlands

Timber assets are carried at cost, less accumulated depletion. Depletion of timber assets is determined based on the number of cubic metres of timber harvested annually at a fixed rate.

(b) Transmission Infrastructure

Transmission assets are carried at cost, less accumulated depreciation. Depreciation on transmission and distribution facilities is provided at various rates on a straight-line basis over the estimated service lives of the assets, which is up to 40 years.

(iv) Development and Other Properties

Development and other properties consist of residential properties, properties for which a major repositioning program is being conducted and properties which are under construction. These properties are recorded at cost, including pre-development expenditures. Homes and other properties held for sale, which include properties subject to sale agreements, are recorded at the lower of cost and estimated fair value. Income received relating to homes and other properties held for sale is applied against the carried value of these properties. Costs are allocated to the saleable acreage of each project or subdivision in proportion to the anticipated revenue.

(v) Financial Assets, Investments and Securities

Financial Assets include securities that are not an active component of the company's asset management operations and are designated as either held-for-trading or available-for-sale. Investments in securities that are actively deployed in the company's operations are classified as securities and are designated as either held-for-trading or available-for-sale. Financial Assets and Securities are recorded at fair value, with changes in fair value accounted for in net income or other comprehensive income as applicable. Equity instruments designated as available-for-sale financial assets and securities that do not have a quoted market price from an active market are carried at cost.

Investments include investments in the securities of affiliates and are accounted for using the equity method of accounting.

Provisions are established in instances where, in the opinion of management, the carrying values of financial assets or securities classified as available-for-sale have been other than temporarily impaired.

(vi) Loans and Notes Receivable

Loans and notes receivable are recorded initially at their fair value and, with the exception of receivables designated as held-for-trading, are subsequently measured at amortized cost using the effective interest method, less any applicable provision for impairment. Loans and notes receivable designated as held-for-trading are recorded at fair value with changes in fair value accounted for in net income in the period in which they arise. A provision for impairment is established when there is objective evidence that the company will not be able to collect all amounts due according to the original terms of the receivables.

(e) Asset Impairment

For assets other than securities and loans and notes receivable, a write-down to estimated fair value is recognized if the estimated undiscounted future cash flows from an asset or group of assets are less than their carried value. The projections of future cash flows take into account the relevant operating plans and management's best estimate of the most probable set of economic conditions anticipated to prevail in the market.

(f) Accounts Receivable and Other

Trade receivables are recognized initially at fair value and subsequently measured at amortized cost using the effective interest method, less any provision for impairment. Included in accounts receivable and other are restricted cash and inventories which are

carried at the lower of average cost and net realizable value and materials and supplies which are valued at the lower of average cost and replacement cost.

(g) Intangible Assets and Liabilities

Intangible assets and liabilities with a finite life are amortized on a straight-line basis over their estimated useful lives, generally not exceeding 20 years, and are tested for impairment when conditions exist which may indicate that the estimated undiscounted future net cash flows from the asset are less than its carrying amount.

(h) Goodwill

Goodwill represents the excess of the price paid for the acquisition of a consolidated entity over the fair value of the net identifiable tangible and intangible assets acquired.

Goodwill is evaluated for impairment annually or more often if events or circumstances indicate there may be an impairment. If the carrying value of a subsidiary, including the allocated goodwill, exceeds its fair value, goodwill impairment is measured as the excess of the carrying amount of the subsidiary's allocated goodwill over the implied fair value of the goodwill, based on the fair value of the assets and liabilities of the subsidiary. Any goodwill impairment is charged to income in the period in which the impairment is identified.

(i) Revenue and Expense Recognition

(i) Asset Management Fee Income

Revenues from performance-based incentive fees are recorded on the accrual basis based upon the amount that would be due under the incentive fee formula at the end of the measurement period established by the contract where it is no longer subject to adjustment based on future events. In some cases this will require that the recognition of performance-based incentive fees be deferred to the end, or towards the end of the contract at which point performance can be more accurately measured.

(ii) Commercial Property Operations

Revenue from a commercial property is recognized upon the earlier of attaining a break-even point in cash flow after debt servicing, or the expiration of a reasonable period of time following substantial completion, but no later than one year following substantial completion. Prior to this, the property is categorized as a property under development, and related revenue is applied to reduce development costs.

The company has retained substantially all of the risks and benefits of ownership of its rental properties and therefore accounts for leases with its tenants as operating leases. The total amount of contractual rent to be received from operating leases is recognized on a straight-line basis over the term of the lease; a straight-line or free rent receivable, as applicable is recorded for the difference between the rental revenue recorded and the contractual amount received. Rental revenue includes percentage participating rents and recoveries of operating expenses, including property, capital and similar taxes. Percentage participating rents are recognized when tenants' specified sales targets have been met. Operating expense recoveries are recognized in the period that recoverable costs are chargeable to tenants.

Revenue from commercial land sales is recognized at the time that the risks and rewards of ownership have been transferred, possession or title passes to the purchaser, all material conditions of the sales contract have been met, and a significant cash down payment or appropriate security is received.

(iii) Power Generation

Revenue from the sale of electricity is recorded at the time power is provided based upon output delivered and capacity provided at rates specified under contract terms or prevailing market rates.

(iv) Infrastructure

(a) Timberlands

Revenue from timberlands is derived from the sale of logs and related products. The company recognizes sales to external customers when the product is shipped and title passes, and collectibility is reasonably assured.

(b) **Transmission Infrastructure**

Revenue from transmission infrastructure assets is derived from the transmission and distribution of electricity to industrial and retail customers. Revenue is recognized at contracted rates when the electricity is delivered, and collectibility is reasonably assured.

(v) **Development and Other Properties**

Revenue from residential land sales is recognized at the time that the risks and rewards of ownership have been transferred, possession or title passes to the purchaser, all material conditions of the sales contract have been met, and a significant cash down payment or appropriate security is received.

Revenue from the sale of homes is recognized when title passes to the purchaser upon closing and at which time all proceeds are received or collectibility is assured.

Revenue from the sale of condominium units is recognized using the percentage-of-completion method at the time that construction is beyond a preliminary stage, sufficient units are sold and all proceeds are received or collectability is assured.

Revenue from construction projects is recognized by the percentage-of-completion method at the time that construction is beyond a preliminary stage, there are indications that the work will be completed according to plan and all proceeds are received or collectibility is assured.

(vi) **Securities and Loans and Notes Receivable**

Revenue from notes receivable, loans and securities, less a provision for uncollectible amounts, is recorded on the accrual basis.

(vii) **Other**

The net proceeds recorded under reinsurance contracts are accounted for as deposits until a reasonable possibility that the company may realize a significant loss from the insurance risk does not exist.

(j) Derivative Financial Instruments

The company and its subsidiaries selectively utilize derivative financial instruments primarily to manage financial risks, including interest rate, commodity and foreign exchange risks. Hedge accounting is applied when the derivative is designated as a hedge of a specific exposure and there is reasonable assurance that it will continue to be effective as a hedge based on an expectation of offsetting cash flows or fair value. Hedge accounting is discontinued prospectively when the derivative no longer qualifies as a hedge or the hedging relationship is terminated. Once discontinued, the cumulative change in fair value of a derivative that was previously deferred by the application of hedge accounting is recognized in income over the remaining term of the original hedging relationship. Balances in respect of unrealized mark-to-market gains or losses on derivative financial instruments are recorded in Accounts Receivables and Other or Accounts Payable and Other Liabilities.

(i) **Items Designated as Hedges**

Realized and unrealized gains and losses on foreign exchange forward contracts and currency swap contracts designated as hedges of currency risks are included in other comprehensive income when the currency risk relates to a net investment in a self-sustaining subsidiary and are otherwise included in income in the same period as when the underlying asset, liability or anticipated transaction affects income.

Unrealized gains and losses on interest rate forward and swap contracts designated as hedges of future interest payments are included in other comprehensive income when the interest rate risk relates to an anticipated interest payments. Unrealized gains and losses on interest rate swaps carried to offset corresponding changes in the values of assets and cash flow streams that are not reflected in the consolidated financial statements at December 31, 2008 and 2007 are recorded in other comprehensive income. The periodic exchanges of payments on interest rate swap contracts designated as hedges of debt are recorded on an accrual basis as an adjustment to interest expense. The periodic exchanges of payments on interest rate contracts designated as hedges of future interest payments are amortized into income over the term of the corresponding interest payments.

Unrealized gains and losses on electricity forward and swap contracts designated as hedges of future power generation revenue are included in other comprehensive income. The periodic exchanges of payments on power generation commodity swap contracts designated as hedges are recorded on a settlement basis as an adjustment to power generation revenue.

(ii) Items not Designated as Hedges

Derivative financial instruments that are not designated as hedges are carried at estimated fair value, and gains and losses arising from changes in fair value are recognized in income in the period the changes occur. Realized and unrealized gains and losses on equity derivatives used to offset the change in share prices in respect of vested Deferred Share Units and Restricted Share Appreciation Units are recorded together with the corresponding compensation expense. Realized and unrealized gains or losses on other derivatives not designated as hedges are recorded in investment and other income.

(k) Income Taxes

The company uses the asset and liability method whereby future income tax assets and liabilities are determined based on differences between the carrying amounts and tax bases of assets and liabilities, and measured using the tax rates and laws that will be in effect when the differences are expected to reverse.

(l) Other Items

(i) Capitalized Costs

Capitalized costs on assets under development and redevelopment include all expenditures incurred in connection with the acquisition, development and construction of the asset until it is available for its intended use. These expenditures consist of costs and interest on debt that is related to these assets. Ancillary income relating specifically to such assets during the development period is treated as a reduction of costs.

(ii) Pension Benefits and Employee Future Benefits

The costs of retirement benefits for defined benefit plans and post-employment benefits are recognized as the benefits earned by employees. The company uses the accrued benefit method pro-rated using the length of service and management's best estimate assumptions to value its pension and other retirement benefits. Assets are valued at fair value for purposes of calculating the expected return on plan assets. For defined contribution plans, the company expenses amounts as paid.

(iii) Liabilities and Equity

Financial instruments that must or could be settled by a variable number of the company's common shares upon their conversion by the holders as well as the related accrued distributions are classified as liabilities on the Consolidated Balance Sheets under the caption "Capital Securities" and are translated into U.S. dollars at period end rates. Dividends and yield distributions on these instruments are classified as Interest expense in the Consolidated Statements of Income.

(iv) Asset Retirement Obligations

Obligations associated with the retirement of tangible long-lived assets are recorded as liabilities when those obligations are incurred, with the amount of the liabilities initially measured at fair value. These obligations are capitalized to the book value of the related long-lived assets and are depreciated over the useful life of the related asset.

(v) Stock-Based Compensation

The company and most of its consolidated subsidiaries account for stock options using the fair value method. Under the fair value method, compensation expense for stock options is determined based on the fair value at the grant date using an option pricing model and charged to income over the vesting period. The company's publicly traded U.S. and Brazilian homebuilding subsidiaries record the liability and expense of stock options based on their intrinsic value using variable plan accounting, reflecting differences in how these plans operate. Under this method, vested options are revalued each reporting period, and any change in value is included in income.

(m) Changes in Accounting Policies Adopted During 2008

(i) Financial Instruments – Disclosures and Presentation

On December 1, 2006, the Canadian Institute of Chartered Accountants ("CICA") issued two new accounting standards, Section 3862, *Financial Instruments – Disclosures* and Section 3863, *Financial Instruments – Presentation*. These standards replace Section 3861, *Financial Instruments – Disclosure and Presentation* and enhance the disclosure of the nature and extent of risks arising from financial instruments and how the entity manages those risks. These new standards became effective for the company on January 1, 2008 and the related disclosures are included as Note 19 to the consolidated financial statements in this report.

(ii) Capital Disclosures

On December 1, 2006, the CICA issued Section 1535, *Capital Disclosures*. Section 1535 requires the disclosure of: (i) an entity's objectives, policies and process for managing capital; (ii) quantitative data about an entity's managed capital; (iii) whether an entity has complied with capital requirements; and (iv) if an entity has not complied with such capital requirements, the consequences of such non-compliance. This new standard became effective for the company on January 1, 2008 and the related disclosures are included as Note 20 to the consolidated financial statements in this report.

(iii) Inventories

In June 2007, the CICA issued Section 3031, *Inventories*, replacing Section 3030, *Inventories*. This standard provides guidance on the determination of the cost of inventories and subsequent recognition as an expense, including any write-down to net realizable value. This new standard became effective for the company on January 1, 2008. The impact of adopting this new standard was a \$4 million reduction of opening retained earnings.

(n) Future Changes in Accounting Policies

(i) Goodwill and Intangible Assets

In February 2008, the CICA issued Handbook Section 3064, *Goodwill and Intangible Assets*, replacing Handbook Sections 3062, *Goodwill and Other Intangible Assets* and 3450, *Research and Development Costs*. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to the financial statements relating to fiscal years beginning January 1, 2009. It establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition of intangible assets by profit-oriented enterprises. The company is currently evaluating the impact of Section 3064 on its financial statements.

(ii) International Financial Reporting Standards

The Accounting Standards Board ("AcSB") confirmed in February 2008 that International Financial Reporting Standards ("IFRS") will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on and after January 1, 2011. The company applied to the Canadian Securities Administrators ("CSA") and was granted exemptive relief to prepare its financial statements in accordance with IFRS earlier than required and intends to do so for periods beginning January 1, 2010, preparing its first financial statements in accordance with IFRS for the three month period ended March 31, 2010. These financial statements will include comparative results for the periods commencing January 1, 2009.

2. ACQUISITIONS

The company accounts for business combinations using the purchase method of accounting which establishes specific criteria for the recognition of intangible assets separately from goodwill. The cost of acquiring a business is allocated to its identifiable tangible and intangible assets and liabilities on the basis of the estimated fair values at the date of purchase with any excess allocated to goodwill.

(a) Completed During 2008

During the first quarter of 2008, the company increased its ownership interest in Brookfield Real Estate Finance Partners ("BREF I") to 33%. As a result, the company consolidates BREF I under the VIE rules. BREF I originates high quality real estate finance investments on a leveraged basis.

The company completed the acquisition of Itiquira Energetica S.A. ("Itiquira") during the second quarter of 2008. Itiquira owns and operates a 156 megawatt hydroelectric facility located on the Itiquira River in Mato Grosso, Brazil.

During the second quarter of 2008, the company acquired MB Engenharia S.A. ("MB"). MB's operations focus on land development and homebuilding in the middle and middle-low segments throughout Brazil.

In the fourth quarter of 2008, a subsidiary of the company merged with Company S.A. ("Company"), diluting Brookfield's ownership in the consolidated entity. Company's operations focus on land development and residential.

In December 2008, the company increased its ownership interest in Norbord Inc. ("Norbord") from 36% to 60% through the purchase of 99 million common shares and 50 million warrants issued as a result of a rights offering. As a result of the increase in

ownership, the company ceased equity accounting for its investment in Norbord and commenced consolidating Norbord. Norbord is an international producer of wood-based panels and oriented strand board.

In addition, the company also acquired \$222 million of net assets which primarily relate to its timber, residential, retail mall and power generation operations.

The following table summarizes the balance sheet impact of significant acquisitions in 2008:

(MILLIONS)	<i>BREF I</i>	<i>Itiquira</i>	<i>MB</i>	<i>Company</i>	<i>Norbord</i>	<i>Other</i>	<i>Total</i>
Cash, accounts receivable and other	\$ 1,389	\$ 67	\$ 212	\$ 396	\$ 127	\$ 8	\$ 2,199
Intangible assets	—	—	—	—	—	28	28
Goodwill	—	—	57	172	—	13	242
Property, plant and equipment	—	436	246	181	791	477	2,131
Non-recourse and corporate borrowings	(977)	(44)	(277)	(418)	(507)	(108)	(2,331)
Accounts payable and other liabilities	(134)	(7)	(174)	(45)	(160)	(21)	(541)
Future income tax asset (liability)	—	(59)	6	—	(73)	(4)	(130)
Non-controlling interests in net assets	(246)	—	(41)	(165)	(106)	(171)	(729)
	\$ 32	\$ 393	\$ 29	\$ 121	\$ 72	\$ 222	\$ 869

(b) Completed During 2007

On April 20, 2007, the company completed the acquisition of Longview Fibre Company for approximately \$2.3 billion including assumed debt and recorded \$593 million of goodwill. With this transaction, the company has acquired 588,000 acres of prime, freehold timberlands in Washington and Oregon and an integrated manufacturing operation that produces specialty papers and containers.

The company completed the acquisition of the Multiplex Group's ("Multiplex") stapled securities in the fourth quarter of 2007, comprising the shares of Multiplex Limited and the units of Multiplex Property Trust for A\$5.05 per stapled security and recorded goodwill of \$694 million. Multiplex is a diversified property business with operations throughout Australia, New Zealand, the United Kingdom and the Middle East. The Multiplex portfolio consists of 24 commercial properties, in addition to construction, development, facilities and funds management divisions.

In December 2007, the company completed the acquisition of a retail mall portfolio consisting of four properties in the São Paulo area and one in Rio de Janeiro. The properties were acquired for approximately \$950 million.

In addition, the company acquired \$972 million of net assets including other commercial properties, hydro generation facilities, and hydro generation developments, together with associated intangibles, working capital and borrowings. Included in this balance is the acquisition of a real estate equity securities manager which resulted in the recording of goodwill of \$55 million in 2007.

The following table summarizes the balance sheet impact of the significant acquisitions in 2007:

(MILLIONS)	<i>Longview</i>	<i>Multiplex</i>	<i>Retail Malls</i>	<i>Other</i>	<i>Total</i>
Cash, accounts receivable and other	\$ 487	\$ 1,650	\$ 13	\$ 56	\$ 2,206
Intangible assets	—	766	—	32	798
Goodwill	593	694	13	57	1,357
Property, plant and equipment	1,985	5,123	1,070	1,777	9,955
Non-recourse and corporate borrowings	(1,350)	(4,325)	(95)	(724)	(6,494)
Accounts payable and other liabilities	(160)	(1,379)	(57)	(29)	(1,625)
Intangible liabilities	—	65	—	(107)	(42)
Future income tax asset (liability)	(593)	87	6	(9)	(509)
Non-controlling interests in net assets	—	(514)	—	(62)	(576)
Preferred equity	—	—	—	(19)	(19)
	\$ 962	\$ 2,167	\$ 950	\$ 972	\$ 5,051

3. FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of a financial instrument 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 bid or ask prices, as appropriate, in the most advantageous active market for that instrument to which the company has immediate access. Where bid and ask prices are unavailable, the closing price of the most recent transaction of that instrument is used. In the absence of an active market, fair values are determined based on prevailing market rates (bid and ask prices, as appropriate) for instruments with similar characteristics and risk profiles or internal or external valuation models, such as option pricing models and discounted cash flow analysis, using observable market inputs.

Fair values determined using valuation models require the use of assumptions concerning the amount and timing of estimated future cash flows and discount rates. In determining those assumptions, the company looks primarily to external readily observable market inputs such as interest rate yield curves, currency rates, and price and rate volatilities as applicable. The fair value of interest rate swap contracts which form part of financing arrangements is calculated by way of discounted cash flows using market interest rates and applicable credit spreads. In limited circumstances, the company uses input parameters that are not based on observable market data and believes that using alternative assumptions will not result in significantly different fair values.

Fair Value of Financial Instruments

Financial instruments classified or designated as held-for-trading or available-for-sale are typically carried at fair value on the Consolidated Balance Sheets. Equity instruments designated as available-for-sale that do not have a quoted market price from an active market are carried at cost. The carrying amount of available-for-sale financial assets that do not have a quoted market price from an active market was \$143 million at December 31, 2008 (2007 – \$182 million). Any changes in the fair values of financial instruments classified as held-for-trading or available-for-sale are recognized in Net Income or Other Comprehensive Income, respectively. The cumulative changes in the fair values of available-for-sale securities previously recognized in Accumulated Other Comprehensive Income are reclassified to Net Income when the underlying security is either sold or there is a decline in value that is considered to be other than temporary. During the year ended December 31, 2008, \$26 million of net deferred losses previously recognized in Accumulated Other Comprehensive Income were reclassified to Net Income as a result of the sale of available-for-sale securities and other than temporary impairment of securities.

Available-for-sale securities measured at fair value or cost are assessed for impairment at each reporting date. As at December 31, 2008, unrealized gains and losses in the fair values of available-for-sale financial instruments measured at fair value amounted to \$25 million (2007 – \$164 million) and \$169 million (2007 – \$243 million) respectively. Unrealized gains and losses for debt and equity securities are primarily due to changing interest rates, market prices and foreign exchange movements. As at December 31, 2008, the company did not consider any investments to be other than temporarily impaired.

Gains or losses arising from changes in the fair value of held-for-trading financial assets are presented in the Consolidated Statements of Income, within investment and other income in the period in which they arise. Dividends on held-for-trading and available-for-sale financial assets are recognized in the Consolidated Statements of Income as part of investment and other income when the company's right to receive payment is established. Interest on available-for-sale financial assets is calculated using the effective interest method and recognized in the Consolidated Statements of Income as part of investment and other income.

Carrying Value and Fair Value of Selected Financial Instruments

The following table provides a comparison of the carrying values and fair values for selected financial instruments as at December 31, 2008 and December 31, 2007.

December 31, 2008						December 31, 2007			
<i>Financial Instrument Classification</i>	<i>Held-for-Trading</i>	<i>Available-for-Sale</i>		<i>Held-to-Maturity</i>	<i>Loans Receivable and Other Liabilities</i>	<i>Total</i>		<i>Total</i>	
<i>Measurement Basis (MILLIONS)</i>	<i>(Fair Value)</i>	<i>(Fair Value)</i>	<i>(Cost)</i>		<i>(Amortized Cost)</i>	<i>(Carrying Value)</i>	<i>(Fair Value)</i>	<i>(Carrying Value)</i>	<i>(Fair Value)</i>
Financial assets									
Cash and cash equivalents	\$ 1,242	\$ —	\$ —	\$ —	\$ —	\$ 1,242	\$ 1,242	\$ 1,561	\$ 1,561
Financial Assets									
Government bonds	130	46	—	—	—	176	176	420	420
Corporate bonds	139	90	—	—	—	229	229	371	371
Fixed income securities	3	33	—	—	—	36	36	62	62
Common shares	72	100	—	—	—	172	172	308	308
Loans receivable	—	—	—	—	174	174	174	368	368
	344	269	—	—	174	787	787	1,529	1,529
Accounts receivable and other	610	—	—	—	3,056	3,666	3,666	3,519	3,519
Securities									
Government bonds	—	381	—	—	—	381	381	465	465
Corporate bonds	—	344	—	—	—	344	344	670	670
Fixed income securities	—	408	—	—	—	408	408	449	449
Common shares	—	27	143	—	—	170	473	244	1,138
	—	1,160	143	—	—	1,303	1,606	1,828	2,722
Loans and notes receivable	—	—	—	1,752	309	2,061	1,596	909	909
	\$ 2,196	\$ 1,429	\$ 143	\$ 1,752	\$ 3,539	\$ 9,059	\$ 8,897	\$ 9,346	\$ 10,240
Financial liabilities									
Corporate borrowings	\$ —	\$ —	\$ —	\$ —	\$ 2,284	\$ 2,284	\$ 2,144	\$ 2,048	\$ 2,068
Property-specific mortgages	—	—	—	—	22,889	22,889	22,376	21,253	21,253
Subsidiary borrowings	—	—	—	—	5,102	5,102	4,863	7,463	7,470
Accounts payable and other	371	—	—	—	7,070	7,441	7,441	8,051	8,051
liabilities									
Capital securities	—	—	—	—	1,425	1,425	1,293	1,570	1,561
	\$ 371	\$ —	\$ —	\$ —	\$ 38,770	\$ 39,141	\$ 38,117	\$ 40,385	\$ 40,403

Hedging Activities

The company uses derivatives and non-derivative financial instruments to manage or maintain exposures to interest, currency, credit and other market risks. When derivatives are used to manage exposures, the company determines for each derivative whether hedge accounting can be applied. Where hedge accounting can be applied, a hedge relationship is designated as a fair value hedge, a cash flow hedge or a hedge of foreign currency exposure of a net investment in a self-sustaining foreign operation. To qualify for hedge accounting the derivative must be highly effective in accomplishing the objective of offsetting changes in the fair value or cash flows attributable to the hedged risk both at inception and over the life of the hedge. If it is determined that the derivative is not highly effective as a hedge, hedge accounting is discontinued prospectively.

Cash Flow Hedges

The company uses energy derivative contracts primarily to hedge the sale of power, interest rate swaps to hedge the variability in cash flows related to a variable rate asset or liability, and equity derivatives to hedge the long-term compensation arrangements. All components of each derivative's change in fair value have been included in the assessment of cash flow hedge effectiveness. For the year ended December 31, 2008, pre-tax net unrealized gains of \$3 million (2007 – loss of \$73 million) were recorded in Other Comprehensive Income for the effective portion of the cash flow hedges.

Net Investment Hedges

The company uses foreign exchange contracts and foreign currency denominated debt instruments to manage its foreign currency exposures to net investments in self-sustaining foreign operations having a functional currency other than the U.S. dollar. For the year ended December 31, 2008, unrealized pre-tax net gains of \$285 million (2007 – loss of \$208 million) were recorded in Other Comprehensive Income for the effective portion of hedges of net investments in self-sustaining foreign operations.

4. INVESTMENTS

Equity accounted investments include the following:

(MILLIONS)	% of Investment		Book Value	
	2008	2007	2008	2007
Chile Transmission	17%	28%	\$ 324	\$ 330
Property funds	20 - 25%	20 - 25%	233	382
Brazil Transmission	3 - 10%	7.5 - 25%	207	205
Norbord Inc.	—	41%	—	180
Real Estate Finance Fund	—	27%	—	148
Other			126	107
Total			\$ 890	\$ 1,352

On March 12, 2008, following a change in the ownership structure of the Real Estate Finance Fund, the company commenced accounting for its investment on a consolidated basis. During the fourth quarter of 2008, the company increased its ownership interest in Norbord Inc. and began accounting for its investment on a consolidated basis.

5. ACCOUNTS RECEIVABLE AND OTHER

(MILLIONS)	Note	2008	2007
Accounts receivable	(a)	\$ 3,056	\$ 2,892
Prepaid expenses and other assets	(b)	3,644	3,620
Restricted cash	(c)	610	627
Total		\$ 7,310	\$ 7,139

(a) Accounts Receivable

Included in accounts receivable are loans receivable from employees of the company and consolidated subsidiaries of \$6 million (2007 – \$4 million).

(b) Prepaid Expenses and Other Assets

Prepaid expenses and other assets includes \$778 million (2007 – \$773 million) of levelized receivables arising from straight-line revenue recognition for commercial property leases and power sales contracts. Also included is \$711 million (2007 – \$932 million) of future income tax assets and \$993 million (2007 – \$807 million) of inventory primarily related to completed residential properties and pulp and paper products.

(c) Restricted Cash

Restricted cash relates primarily to commercial property and power generating financing arrangements including defeasement of debt obligations, debt service accounts and deposits held by the company's insurance operations.

6. INTANGIBLE ASSETS

Intangible assets includes \$1,470 million (2007 – \$1,953 million) related to leases and tenant relationships allocated from the purchase price on the acquisition of commercial properties which is presented net of \$526 million (2007 – \$275 million) accumulated amortization.

7. PROPERTY, PLANT AND EQUIPMENT

(MILLIONS)	Note	2008	2007
Commercial properties	(a)	\$ 19,274	\$ 20,796
Power generation	(b)	4,954	5,137
Infrastructure	(c)	2,879	3,046
Development and other properties	(d)	7,282	7,696
Other plant and equipment	(e)	1,986	1,050
Total		\$ 36,375	\$ 37,725

(a) Commercial Properties

(MILLIONS)	2008	2007
Commercial properties	\$ 20,711	\$ 22,086
Less: accumulated depreciation	1,437	1,290
Total	\$ 19,274	\$ 20,796

Commercial properties carried at a net book value of approximately \$3,934 million (2007 – \$4,000 million) are situated on land held under leases or other agreements largely expiring after the year 2099. Minimum rental payments on land leases are approximately \$29 million (2007 – \$28 million) annually for the next five years and \$3,298 million (2007 – \$3,256 million) in total on an undiscounted basis.

Construction costs of \$103 million and interest costs of \$46 million were capitalized to the commercial property portfolio for properties undergoing redevelopment in 2008 (2007 – \$40 million and \$31 million respectively).

(b) Power Generation

(MILLIONS)	2008	2007
Hydroelectric power facilities	\$ 5,233	\$ 5,095
Wind energy	326	393
Co-generation and pumped storage	313	362
	5,872	5,850
Less: accumulated depreciation	1,018	949
	4,854	4,901
Generating facilities under development	100	236
Total	\$ 4,954	\$ 5,137

Generation assets includes the cost of the company's 162 hydroelectric generating stations, wind energy, pumped storage and two natural gas-fired cogeneration facilities. The company's hydroelectric power facilities operate under various agreements for water rights which extend to or are renewable over terms through the years 2009 to 2046.

(c) Infrastructure

(MILLIONS)	Note	2008	2007
Timberlands	(i)	\$ 2,721	\$ 2,853
Transmission	(ii)	158	193
Total		\$ 2,879	\$ 3,046

(i) Timberlands

(MILLIONS)	2008	2007
Timberlands	\$ 2,987	\$ 3,202
Other property, plant and equipment	19	21
	3,006	3,223
Less: accumulated depletion and amortization	285	370
Total	\$ 2,721	\$ 2,853

(ii) Transmission

<i>(MILLIONS)</i>	<i>2008</i>	<i>2007</i>
Transmission lines and infrastructure	\$ 167	\$ 186
Other property, plant and equipment	82	90
	249	276
Less: accumulated depreciation	91	83
Total	\$ 158	\$ 193

The company's transmission infrastructure assets are comprised of power transmission and distribution networks, which are operated under regulated rate base arrangements that are applied to the company's invested capital.

(d) Development and Other Properties

Development and other properties include properties relating to the company's opportunity investments, residential properties, properties under development and properties held for development, and construction operations.

<i>(MILLIONS)</i>	<i>Note</i>	<i>2008</i>	<i>2007</i>
Opportunity investments	<i>(i)</i>	\$ 850	\$ 981
Residential	<i>(ii)</i>	1,927	1,850
Under development	<i>(iii)</i>	2,141	3,660
Held for development	<i>(iii)</i>	2,240	1,158
Construction		124	47
Total		\$ 7,282	\$ 7,696

(i) Opportunity Investments

<i>(MILLIONS)</i>	<i>2008</i>	<i>2007</i>
Commercial and other properties	\$ 926	\$ 1,017
Less: accumulated depreciation	76	36
Total	\$ 850	\$ 981

(ii) Residential

<i>(MILLIONS)</i>	<i>2008</i>	<i>2007</i>
Residential properties — owned	\$ 1,858	\$ 1,747
— optioned	69	103
Total	\$ 1,927	\$ 1,850

Residential properties include infrastructure, land (owned and under option), and construction in progress for single-family homes and condominiums. During 2008, the company capitalized \$148 million of interest (2007 – \$85 million) of interest to its residential land operations.

(iii) Under Development and Held for Development

Properties that are currently under development or held for future development include commercial developments, residential land, and rural lands held for future development in agricultural or residential areas. During 2008, the company capitalized construction related costs of \$298 million (2007 – \$203 million) and interest costs of \$99 million (2007 – \$58 million) to its commercial development sites.

(e) Other Plant and Equipment

Other plant and equipment includes capital assets associated primarily with the company's investments in Fraser Papers, Norbord, Western Forest Products, and restructuring funds.

8. SECURITIES

(MILLIONS)	2008	2007
Government bonds	\$ 381	\$ 465
Corporate bonds	344	670
Fixed income securities	408	449
Common shares	27	62
Canary Wharf Group common shares	143	182
Total	\$ 1,303	\$ 1,828

Securities represent holdings that are actively deployed in the company's financial operations and include \$954 million (2007 – \$1,638 million) owned through the company's insurance operations.

Corporate bonds include fixed-rate securities totalling \$340 million (2007 – \$634 million) with an average yield of 6.1% (2007 – 5.2%) and an average maturity of approximately three years. Government bonds and fixed-income securities include predominantly fixed-rate securities.

During the fourth quarter of 2008, the company transferred its investment in Canary Wharf Group to a pound sterling self-sustaining subsidiary.

9. LOANS AND NOTES RECEIVABLE

Loans and notes receivable include corporate loans, bridge loans and other loans, either advanced directly or acquired in the secondary market.

The fair value of the company's loans and notes receivable at December 31, 2008 is below the carrying value by \$465 million (2007 – \$nil million) based on expected future cash flows, discounted at market rates for assets with similar terms and investment risks.

The loans and notes receivable mature over the next eight years (2007 – five years), with an average maturity of approximately one year (2007 – two years) and include fixed rate loans totalling \$107 million (2007 – \$5 million) with an average yield of 7.4% (2007 – 10.0%).

10. CORPORATE BORROWINGS

(MILLIONS)	Market	Maturity	Annual Rate	Currency	2008	2007
Term debt	Public – U.S.	December 12, 2008	8.13%	US\$	\$ —	\$ 300
Term debt	Public – U.S.	March 1, 2010	5.75%	US\$	200	200
Term debt	Public – U.S.	June 15, 2012	7.13%	US\$	350	350
Term debt	Private – U.S.	October 23, 2012	6.40%	US\$	75	—
Term debt	Private – U.S.	October 23, 2013	6.65%	US\$	75	—
Term debt	Public – U.S.	April 25, 2017	5.80%	US\$	250	250
Term debt	Public – Canadian	April 25, 2017	5.29%	C\$	205	250
Term debt	Public – U.S.	March 1, 2033	7.38%	US\$	250	250
Term debt	Public – Canadian	June 14, 2035	5.95%	C\$	246	300
Commercial paper and bank borrowings			L + 63 b.p.	US\$/C\$	649	167
Deferred financing costs ¹					(16)	(19)
Total					\$ 2,284	\$ 2,048

¹ Deferred financing costs are amortized to interest expense over the term of the borrowing following the effective interest method

L – One month LIBOR b.p. – Basis Points

Term debt borrowings have a weighted average interest rate of 6.3% (2007 – 6.6%), and include \$451 million (2007 – \$550 million) repayable in Canadian dollars equivalent to C\$550 million (2007 – C\$550 million).

The fair value of corporate borrowings at December 31, 2008 was below the company's carrying values by \$140 million (2007 – exceeded by \$20 million), determined by way of discounted cash flows using market rates adjusted for the company's

credit spreads. Corporate borrowings are recorded initially at their fair value, net of transaction costs incurred, and are subsequently reported at their amortized cost calculated using the effective interest method.

In October 2008, the company issued \$150 million of unsecured private placement term debt comprising \$75 million of 5 year, 6.65% notes and \$75 million of 4 year 6.4% notes. In December 2008, the company repaid a \$300 million corporate debt maturity.

11. NON-RECOURSE BORROWINGS

(a) Property-Specific Mortgages

Principal repayments on property-specific mortgages due over the next five years and thereafter are as follows:

(MILLIONS)	Commercial Properties	Power Generation	Infrastructure	Development and Other Properties	Specialty Funds	Annual Repayments	Total
2009	\$ 1,109	\$ 329	\$ —	\$ 956	\$ 30	\$	\$ 2,424
2010	1,315	199	34	1,022	580		3,150
2011	4,487	182	32	279	—		4,980
2012	264	639	—	292	66		1,261
2013	1,925	103	424	66	—		2,518
Thereafter	4,770	2,136	1,152	61	437		8,556
Total – 2008	\$ 13,870	\$ 3,588	\$ 1,642	\$ 2,676	\$ 1,113	\$	\$ 22,889
Total – 2007	\$ 13,314	\$ 3,488	\$ 1,796	\$ 3,046	\$ —	\$	\$ 21,644

Property-specific mortgages include \$3,005 million (2007 – \$3,211 million) repayable in Canadian dollars equivalent to C\$3,670 million (2007 – C\$3,206 million); \$846 million (2007 – \$164 million) in Brazilian real equivalent to R\$1,978 million (2007 – R\$291 million); \$725 million (2007 – \$561 million) in British pounds equivalent to £496 million (2007 – £283 million); \$101 million (2007 – \$nil) in New Zealand dollars equivalent to NZ\$171 million (2007 – NZ\$nil); and \$2,074 million (2007 – \$2,360 million) in Australian dollars equivalent to A\$2,943 million (2007 – A\$2,697 million). The weighted average interest rate at December 31, 2008 was 5.8% per annum (2007 – 6.1%).

Property-specific mortgages are recorded initially at their fair value, net of transaction costs incurred, and are subsequently reported at their amortized cost calculated using the effective interest method.

The fair value of property-specific mortgages was below the company's carrying values by \$513 million (2007 – \$nil), determined by way of discounted cash flows using market rates adjusted for credit spreads applicable to the debt.

(b) Subsidiary Borrowings

Principal repayments on subsidiary borrowings over the next five years and thereafter are as follows:

(MILLIONS)	Commercial Properties	Power Generation	Infrastructure	Development and Other Properties	Other	Annual Repayments	Total
2009	\$ 360	\$ 369	\$ 4	\$ 393	\$ 297	\$	\$ 1,423
2010	80	—	1	497	168		746
2011	—	—	141	54	385		580
2012	—	—	—	19	273		292
2013	711	—	—	99	15		825
Thereafter	—	284	—	33	919		1,236
Total – 2008	\$ 1,151	\$ 653	\$ 146	\$ 1,095	\$ 2,057	\$	\$ 5,102
Total – 2007	\$ 2,793	\$ 797	\$ 8	\$ 1,389	\$ 2,089	\$	\$ 7,076

The fair value of subsidiary borrowings was below the company's carrying values by \$239 million (2007 – exceeded by \$7 million), determined by way of discounted cash flows using market rates adjusted for applicable credit spreads.

Subsidiary borrowings include \$1,034 million (2007 – \$1,504 million) repayable in Canadian dollars equivalent to C\$1,262 million (2007 – C\$1,502 million); \$552 million (2007 – \$820 million) in Brazilian real equivalent to R\$1,290 million (2007 – R\$1,455 million); \$9 million (2007 – \$9 million) in British pounds equivalent to £6 million (2007 – £4 million); \$47 million (2007 – \$25 million) in European euros equivalent to €33 million (2007 – €17 million); \$760 million (2007 – \$1,573 million) in Australian dollars

equivalent to A\$1,078 million (2007 – A\$1,798 million); and \$nil (2007 – \$126 million) in Japanese yen equivalent to ¥nil (2007 – ¥14,030 million). The weighted average interest rate at December 31, 2008 was 6.4% per annum (2007 – 9.3%).

Commercial properties includes \$240 million (2007 – \$257 million) invested by investment partners in the form of debt capital in entities that are required to be consolidated into the company's accounts.

Residential property debt represents amounts drawn under construction financing facilities which are typically established on a project-by-project basis. Amounts drawn are repaid from the proceeds on the sale of building lots, single-family homes and condominiums and redrawn to finance the construction of new homes.

Subsidiary borrowings include obligations pursuant to financial instruments which are recorded as liabilities. These amounts include \$675 million (2007 – \$584 million) of subsidiary obligations relating to the company's international operations that are subject to credit rating provisions and which are supported by corporate guarantees.

Subsidiary borrowings are recorded initially at their fair value, net of transaction costs incurred, and are subsequently reported at their amortized costs calculated using the effective interest method.

12. ACCOUNTS PAYABLE AND OTHER LIABILITIES

(MILLIONS)	Note	2008	2007
Accounts payable	(a)	\$ 4,494	\$ 5,020
Other liabilities and future tax liabilities	(b)	4,409	4,843
Total		\$ 8,903	\$ 9,863

(a) Accounts Payable

Accounts payable include \$1,014 million (2007 – \$1,560 million) of insurance deposits, claims and other liabilities incurred by the company's insurance subsidiaries.

(b) Other Liabilities and Future Tax Liabilities

Other liabilities include the fair value of the company's obligations to deliver securities it did not own at the time of sale and obligations pursuant to financial instruments. Future tax liabilities as at December 31, 2008 are \$1,461 million (2007 – \$1,925 million).

13. INTANGIBLE LIABILITIES

Intangible liabilities represent below-market tenant leases and above-market ground leases assumed on acquisitions, net of accumulated amortization. At December 31, 2008, \$891 million (2007 – \$1,112 million) of below market leases were recorded net of \$374 million amortization (2007 – \$218 million).

14. CAPITAL SECURITIES

The company has the following capital securities outstanding:

(MILLIONS)	Note	2008	2007
Corporate preferred shares	(a)	\$ 543	\$ 517
Subsidiary preferred shares	(b)	882	1,053
Total		\$ 1,425	\$ 1,570

(a) Corporate Preferred Shares and Preferred Securities

(MILLIONS, EXCEPT SHARE INFORMATION)	Shares Outstanding	Description	Cumulative Distribution Rate	Currency		
					2008	2007
Class A preferred shares	10,000,000	Series 10	5.75%	C\$	\$ 205	\$ 251
	4,032,401	Series 11	5.50%	C\$	83	101
	7,000,000	Series 12	5.40%	C\$	143	175
	6,000,000	Series 21	5.00%	C\$	123	—
Deferred financing costs					(11)	(10)
Total					\$ 543	\$ 517

On June 25, 2008, the company issued 6,000,000 Class A Series 21, 5% preferred shares for cash proceeds of C\$150 million, and incurred transaction costs of C\$5 million.

Subject to approval of the Toronto Stock Exchange, the Series 10, 11, 12 and 21 shares, unless redeemed by the company for cash, are convertible into Class A common shares at a price equal to the greater of 95% of the market price at the time of conversion and C\$2.00, at the option of either the company or the holder, at any time after the following dates:

Class A Preferred Shares	Earliest Permitted Redemption Date	Company's Conversion Option	Holder's Conversion Option
Series 10	September 30, 2008	September 30, 2008	March 31, 2012
Series 11	June 30, 2009	June 30, 2009	December 31, 2013
Series 12	March 31, 2014	March 31, 2014	March 31, 2018
Series 21	June 30, 2013	June 30, 2013	June 30, 2013

(b) Subsidiary Preferred Shares

(MILLIONS, EXCEPT SHARE INFORMATION)	Shares Outstanding	Description	Cumulative Dividend Rate	Currency		
					2008	2007
Class AAA preferred shares of	8,000,000	Series F	6.00%	C\$	\$ 164	\$ 200
Brookfield Properties Corporation	4,400,000	Series G	5.25%	US\$	110	110
	8,000,000	Series H	5.75%	C\$	164	200
	8,000,000	Series I	5.20%	C\$	164	200
	8,000,000	Series J	5.00%	C\$	164	200
	6,000,000	Series K	5.20%	C\$	123	150
Deferred financing costs					(7)	(7)
Total					\$ 882	\$ 1,053

The subsidiary preferred shares are redeemable at the option of either the company or the holder, at any time after the following dates:

Class AAA Preferred Shares	Earliest Permitted Redemption Date	Company's Conversion Option	Holder's Conversion Option
Series F	September 30, 2009	September 30, 2009	March 31, 2013
Series G	June 30, 2011	June 30, 2011	September 30, 2015
Series H	December 31, 2011	December 31, 2011	December 31, 2015
Series I	December 31, 2008	December 31, 2008	December 31, 2010
Series J	June 30, 2010	June 30, 2010	December 31, 2014
Series K	December 31, 2012	December 31, 2012	December 31, 2016

15. NON-CONTROLLING INTERESTS IN NET ASSETS

Non-controlling interests in net assets represent the common and preferred equity in consolidated entities that is owned by other shareholders.

(MILLIONS)	2008	2007
Common equity	\$ 5,883	\$ 4,232
Preferred equity	446	538
Total	\$ 6,329	\$ 4,770

16. PREFERRED EQUITY

Preferred equity represents perpetual preferred shares.

(MILLIONS, EXCEPT SHARE INFORMATION)	Rate	Term	Issued and Outstanding		2008	2007
			2008	2007		
Class A preferred shares						
Series 2	70% P	Perpetual	10,465,100	10,465,100	\$ 169	\$ 169
Series 4	70% P/8.5%	Perpetual	2,800,000	2,800,000	45	45
Series 8	Variable up to P	Perpetual	1,805,948	1,805,948	29	29
Series 9	4.35%	Perpetual	2,194,052	2,194,052	35	35
Series 13	70% P	Perpetual	9,297,700	9,297,700	195	195
Series 15	B.A. + 40 b.p. ¹	Perpetual	2,000,000	2,000,000	42	42
Series 17	4.75%	Perpetual	8,000,000	8,000,000	174	174
Series 18	4.75%	Perpetual	8,000,000	8,000,000	181	181
Total					\$ 870	\$ 870

¹ Rate determined in a quarterly auction

P – Prime Rate B.A. – Bankers' Acceptance Rate b.p. – Basis Points

The company is authorized to issue an unlimited number of Class A preferred shares and an unlimited number of Class AA preferred shares, issuable in series. No Class AA preferred shares have been issued.

The Class A preferred shares have preference over the Class AA preferred shares, which in turn are entitled to preference over the Class A and Class B common shares on the declaration of dividends and other distributions to shareholders. All series of the outstanding preferred shares have a par value of C\$25 per share.

17. COMMON EQUITY

The company is authorized to issue an unlimited number of Class A Limited Voting Shares ("Class A common shares") and 85,120 Class B Limited Voting Shares ("Class B common shares"), together referred to as common shares.

The company's common shareholders' equity is comprised of the following:

(MILLIONS)	2008	2007
Class A and B common shares	\$ 1,278	\$ 1,275
Contributed surplus	42	57
Retained earnings	4,368	4,867
Accumulated other comprehensive (loss) income	(770)	445
Common equity	\$ 4,918	\$ 6,644
NUMBER OF SHARES		
Class A common shares	572,479,652	583,527,581
Class B common shares	85,120	85,120
	572,564,772	583,612,701
Unexercised options	27,761,269	27,344,215
Total diluted common shares	600,326,041	610,956,916

(a) Class A and Class B Common Shares

The company's Class A common shares and its Class B common shares are each, as a separate class, entitled to elect one-half of the company's Board of Directors. Shareholder approvals for matters other than for the election of directors must be received from the holders of the company's Class A common shares as well as the Class B common shares, each voting as a separate class.

During 2008 and 2007, the number of issued and outstanding common shares changed as follows:

	2008	2007
Outstanding at beginning of year	583,612,701	581,815,929
Shares issued (repurchased)		
Dividend reinvestment plan	161,386	71,251
Management share option plan	3,014,077	4,920,468
Business acquisitions	—	1,795,297
Repurchases	(14,224,303)	(4,985,802)
Other	911	(4,442)
Outstanding at end of year	572,564,772	583,612,701

In 2008, the company repurchased 14,224,303 (2007 – 4,985,802) Class A common shares under normal course issuer bids at a cost of \$287 million (2007 – \$163 million). Proceeds from the issuance of common shares pursuant to the company's dividend reinvestment plan and management share option plan ("MSOP"), totalled \$33 million (2007 – \$45 million).

On November 16, 2007, the company issued 1,795,297 Class A common shares to acquire a real estate securities manager representing consideration of \$66 million.

(b) Earnings Per Share

The components of basic and diluted earnings per share are summarized in the following table:

(MILLIONS)	2008	2007
Net income	\$ 649	\$ 787
Preferred share dividends	(44)	(44)
Net income available for common shareholders	\$ 605	\$ 743
Weighted average outstanding common shares	581.1	582.4
Dilutive effect of options using treasury stock method	10.8	17.1
Common shares and common share equivalents	591.9	599.5

The holders of Class A common shares and Class B common shares rank on parity with each other with respect to the payment of dividends and the return of capital on the liquidation, dissolution or winding up of the company or any other distribution of the assets of the company among its shareholders for the purpose of winding up its affairs. With respect to the Class A and Class B common shares, there are no dilutive factors, material or otherwise, that would result in different diluted earnings per share. This relationship holds true irrespective of the number of dilutive instruments issued in either one of the respective classes of common stock, as both classes of common shares participate equally, on a pro rata basis in the dividends, earnings and net assets of the company, whether taken before or after dilutive instruments, regardless of which class of common shares is diluted.

(c) Stock-Based Compensation

Options issued under the company's MSOP typically vest proportionately over five years and expire 10 years after the grant date. The exercise price is equal to the market price at the grant date. During 2008, the company granted 3,823,000 (2007 – 3,516,763) options with an average exercise price of \$31.21 (C\$31.47) (2007 – C\$38.67) per share. The cost of the options granted was determined using the Black-Scholes model of valuation, assuming a 7.5 year term to exercise (2007 – 7.5 year), 27% volatility (2007 – 22%), a weighted average expected annual dividend yield of 1.7% (2007 – 1.2%) and a risk-free rate of 3.9% (2007 – 4.0%). The cost of \$21 million (2007 – \$26 million) is charged to employee compensation expense on an equal basis over the five-year vesting period of the options granted.

The changes in the number of options during 2008 and 2007 were as follows:

	2008		2007	
	Number of Options (000's)	Weighted Average Exercise Price	Number of Options (000's)	Weighted Average Exercise Price
Outstanding at beginning of year	27,344	C\$ 17.12	28,992	C\$ 13.25
Granted	3,823	31.47	3,517	38.67
Exercised	(3,014)	10.18	(4,921)	9.20
Cancelled	(392)	34.54	(244)	26.87
Outstanding at end of year	27,761	C\$ 19.61	27,344	C\$ 17.12
Exercisable at end of year	16,671		15,876	

At December 31, 2008, the following options to purchase Class A common shares were outstanding:

Number Outstanding (000's)	Exercise Price	Weighted Average Remaining Life	Number Exercisable (000's)
1,439	C\$4.90 – C\$5.69	1.3 years	1,439
3,875	C\$5.72 – C\$8.56	2.1 years	3,875
4,510	C\$8.71 – C\$12.28	3.8 years	4,490
3,011	C\$13.37 – C\$16.63	5.3 years	2,374
8,022	C\$19.71 – C\$29.47	6.5 years	3,825
6,904	C\$29.91 – C\$46.59	8.7 years	668
27,761			16,671

A Restricted Share Unit Plan provides for the issuance of Deferred Share Units (“DSUs”), as well as Restricted Share Appreciation Units (“RSAUs”). Under this plan, qualifying employees and directors receive varying percentages of their annual incentive bonus or directors’ fees in the form of DSUs. The DSUs and RSAUs vest over periods of up to five years, and DSUs accumulate additional DSUs at the same rate as dividends on common shares based on the market value of the common shares at the time of the dividend. Participants are not allowed to convert DSUs and RSAUs into cash until retirement or cessation of employment. The value of the DSUs, when converted to cash, will be equivalent to the market value of the common shares at the time the conversion takes place. The value of the RSAUs when converted into cash will be equivalent to the difference between the market price of equivalent numbers of common shares at the time the conversion takes place, and the market price on the date the RSAUs are granted. The company uses equity derivative contracts to offset its exposure to the change in share prices in respect of vested and unvested DSUs and RSAUs. The value of the vested DSUs and RSAUs as at December 31, 2008 was \$132 million (2007 – \$372 million).

Employee compensation expense for these plans is charged against income over the vesting period of the DSUs and RSAUs. The amount payable by the company in respect of vested DSUs and RSAUs changes as a result of dividends and share price movements. All of the amounts attributable to changes in the amounts payable by the company are recorded as employee compensation expense in the period of the change, and for the year ended December 31, 2008, including those of operating subsidiaries, totalled \$61 million (2007 – \$48 million), net of the impact of hedging arrangements.

18. DERIVATIVE FINANCIAL INSTRUMENTS

The company’s activities expose it to a variety of financial risks, including market risk (i.e. currency risk, interest rate risk, and other price risk), credit risk and liquidity risk. The company and its subsidiaries selectively use derivative financial instruments principally to manage these risks.

The aggregate notional amount of the company's derivative positions at the end of 2008 and 2007 are as follows:

(MILLIONS)	Note	2008	2007
Foreign exchange	(a)	\$ 3,607	\$ 2,887
Interest rates	(b)	8,085	8,694
Credit default swaps	(c)	2,465	2,350
Equity derivatives	(d)	417	870
Commodity instruments (energy)	(e)	198	193
		\$ 14,772	\$ 14,994

(a) Foreign Exchange

At December 31, 2008, the company held foreign exchange contracts with a notional amount of \$361 million (2007 – \$1,562 million) at an average exchange rate of \$1.22 (2007 – \$1.01) to manage its Canadian dollar exposure. At December 31, 2008, the company held foreign exchange contracts with a notional amount of \$960 million (2007 – \$198 million) at an average exchange rate of \$1.48 (2007 – \$1.99) to manage its British pound exposure. The company also held foreign exchange contracts with a notional amount of \$1,053 million (2007 – \$nil) at an average exchange rate of 0.67 to manage its Australian dollar exposure. The company held cross currency interest rate swap contracts with a notional amount of \$864 million (2007 – \$946 million), to manage its Canadian dollar and Australian dollar exposure. The remaining foreign exchange contracts relate to the company's Brazilian and European operations.

Included in 2008 income, are net gains on foreign currency balances amounting to \$37 million (2007 – net losses of \$24 million) and included in the cumulative translation adjustment account in other comprehensive income are gains in respect of foreign currency contracts entered into for hedging purposes amounting to \$139 million (2007 – net losses of \$60 million), which are offset by translation losses on the underlying net assets.

(b) Interest Rates

At December 31, 2008, the company held interest rate swap contracts having an aggregate notional amount of \$400 million (2007 – \$1,200 million). The company's subsidiaries held interest rate swap contracts having an aggregate notional amount of \$3,292 million (2007 – \$3,191 million) of which \$400 million (2007 – \$400 million) was guaranteed by the company. The company's subsidiaries held interest rate cap contracts with an aggregate notional amount of \$4,393 million (2007 – \$4,303 million).

(c) Credit Default Swaps

As at December 31, 2008, the company held credit default swap contracts with an aggregate notional amount of \$2,465 million (2007 – \$2,350 million). Credit default swaps are contracts which are designed to compensate the purchaser for any change in value of an underlying reference asset, based on measurement in credit spreads, upon the occurrence of predetermined credit events. The company is entitled to receive payments in the event of a predetermined credit event for up to \$2,407 million (2007 – \$2,334 million) of the notional amount and could be required to make payments in respect of \$58 million (2007 – \$16 million) of the notional amount.

(d) Equity Derivatives

At December 31, 2008, the company and its subsidiaries held equity derivatives with a notional amount of \$417 million (2007 – \$870 million) recorded at an amount equal to fair value. A portion of the notional amount represents a hedge of long-term compensation arrangements and the balance represents common equity positions established in connection with the company's investment activities. The fair value of these instruments was reflected in the company's consolidated financial statements at year end.

(e) Commodity Instruments

The company has entered into energy derivative contracts primarily to hedge the sale of generated power. The company endeavours to link forward electricity sale derivatives to specific periods in which it expects to generate electricity for sale. All energy derivative contracts are recorded at an amount equal to fair value and are reflected in the company's consolidated financial statements at year end.

Other Information Regarding Derivative Financial Instruments

The following table classifies derivatives elected as either fair value hedges, cash flow hedges or net investment hedges, and

presents the effective portion of the hedge recorded in either other comprehensive income or in income, depending on the hedge classification and the ineffective portion of the hedge recorded in Net Income during the year:

(MILLIONS)	Net Gain (Losses)		
	Notional	Effective Portion	Ineffective Portion
Fair value hedges	\$ 238	\$ (5)	\$ (2)
Cash flow hedges	6,722	21	(7)
Net investment hedges	2,750	136	—
	\$ 9,710	\$ 152	\$ (9)

The following table presents the notional amounts underlying the company's derivative instruments by term to maturity, as at December 31, 2008, for both derivatives that are held-for-trading and derivatives that qualify for hedge accounting:

	Residual Term to Contractual Maturity			Total Notional
(MILLIONS)	< 1 year	1 to 5 years	> 5 years	Amount
Held-for-trading				
Foreign exchange derivatives	\$ 204	\$ 148	\$ —	\$ 352
Interest rate derivatives				
Interest rate swaps	192	631	505	1,328
Interest rate caps	357	36	—	393
	549	667	505	1,721
Credit default swaps	10	2,453	2	2,465
Equity derivatives	4	372	33	409
Commodity derivatives	35	9	71	115
	\$ 802	\$ 3,649	\$ 611	\$ 5,062
Elected for hedge accounting				
Foreign exchange derivatives	\$ 2,421	\$ 650	\$ 184	\$ 3,255
Interest rate derivatives				
Interest rate swaps	964	1,375	25	2,364
Interest rate caps	—	4,000	—	4,000
	964	5,375	25	6,364
Equity derivatives	—	8	—	8
Commodity derivatives	13	70	—	83
	\$ 3,398	\$ 6,103	\$ 209	\$ 9,710
	\$ 4,200	\$ 9,752	\$ 820	\$ 14,772

The following table presents the change in fair values of the company's derivative positions during the years ended December 31, 2008 and 2007, for both derivatives that are held-for-trading and derivatives that qualify for hedge accounting:

(MILLIONS)	Unrealized Gains During 2008	Unrealized Losses During 2008	Net Change During 2008	2007 Net Change
Foreign exchange derivatives	\$ 218	\$ (42)	\$ 176	\$ (84)
Interest rate derivatives				
Interest rate swaps	195	(375)	(180)	(127)
Interest rate caps	2	—	2	—
	197	(375)	(178)	(127)
Credit default swaps	47	(20)	27	98
Equity derivatives	19	(238)	(219)	(38)
Commodity derivatives	304	(157)	147	(58)
	\$ 785	\$ (832)	\$ (47)	\$ (209)

19. RISK MANAGEMENT

The company is exposed to the following risks as a result of holding financial instruments: market risk (i.e. interest rate risk, currency risk and other price risks that impact the fair values of financial instruments); credit risk; and liquidity risk. The following is a description of these risks and how they are managed:

a) Market risk

Market risk is defined for these purposes as the risk that the fair value or future cash flows of a financial instrument held by the company will fluctuate because of changes in market prices. Market risk includes the risk of changes in interest rates, currency exchange rates and changes in market prices due to factors other than interest rates or currency exchange rates such as equity prices, commodity prices or credit spreads.

The company attempts to reduce market risk from foreign currency assets and liabilities and the impact at changes in interest rates, floating rate assets and liabilities by funding assets with financial liabilities in the same currency and with similar interest rate characteristics and holding financial contracts such as interest rate and foreign exchange derivatives to minimize residual exposures. Financial instruments held by the company that are subject to market risk include securities and loans receivable, borrowings, and derivative instruments such as interest rate, currency, equity and commodity contracts. The categories of financial instruments that can potentially give rise to significant variability are described in the following paragraphs.

Interest rate risk

The observable impacts on the fair values and future cash flows of financial instruments that can be directly attributable to interest rate risk include changes in the net income from financial instruments whose cash flows are determined with reference to floating interest rates and changes in the value of financial instruments whose cash flows are fixed in nature.

The company's assets largely consist of long duration interest sensitive physical assets. Accordingly, the company's financial liabilities consist primarily of long-term fixed rate debt or floating rate debt that has been swapped to floating rates or fixed rates with interest rate derivatives. These financial liabilities are, with few exceptions, recorded at their amortized cost. The company also holds interest rate caps to limit its exposure to increases in interest rates on floating rate debt that has not been swapped and holds interest rate contracts to lock in fixed rates on anticipated future debt issuances and as an economic hedge against the values of long duration interest sensitive physical assets that have not been otherwise matched with fixed rate debt.

The result of a 50 basis point increase in interest rates on the company's net floating rate assets and liabilities would have resulted in a corresponding decrease in net income before tax of \$13 million on an annualized basis.

Changes in the value of held-for-trading interest rate contracts are recorded in net income and changes in the value of contracts that are elected for hedge accounting together with changes in the value of available-for-sale financial instruments are recorded in other comprehensive income together with the change in the value of the item being hedged. The impact of a 10 basis point parallel increase in the yield curve on the aforementioned financial instruments is estimated to result in a corresponding increase in net income of \$8 million and an increase in other comprehensive income of \$1 million, before tax as at December 31, 2008.

Currency risk

Changes in currency rates will impact the carrying value of financial instruments denominated in currencies other than the U.S. dollar in addition to any changes in the value of the financial instruments in the relevant foreign currency due to other risks.

The company holds financial instruments with net unmatched exposures in several currencies, changes in the translated value of which are recorded in net income. The impact of a 1% increase in the U.S. dollar against these currencies would have resulted in a \$21 million increase in the value of these positions on a combined basis, of which \$14 million relates to the Canadian dollar. The impact on cash flows from financial instruments would be insignificant. The company holds financial instruments to hedge the net investment in self-sustaining operations whose functional and reporting currencies are other than the U.S. dollar. A 1% increase in the U.S. dollar would increase the value of these hedging instruments by \$40 million as at December 31, 2008, which would be recorded in other comprehensive income and offset by changes in the U.S. dollar carrying value of the net investment being hedged.

Other price risk

Other price risk is the risk of variability in fair value due to movements in equity prices or other market prices such as commodity prices and credit spreads.

Financial instruments held by the company that are exposed to equity price risk include equity securities and equity derivatives. A 5% increase in the market price of equity securities and equity derivatives held by the company, excluding equity derivatives in respect of compensation arrangements, would have increased net income by \$1 million and decreased other comprehensive

income by \$2 million, prior to taxes. The company's liability in respect of equity compensation arrangements is subject to variability based on changes in the company's underlying common share price. The company holds equity derivatives to hedge almost all of the variability. A 5% change in the common equity price of the company in respect of compensation agreements would increase the compensation liability and compensation expense by \$15 million. This increase would be offset by a \$15 million change in value of the associated equity derivatives of which \$14 million would offset the above mentioned increase in compensation expense and the remaining \$1 million would be recorded in other comprehensive income.

The company sells power and generation capacity under long-term agreements or financial contracts to stabilize future revenues. Certain of the contracts are considered financial instruments and are recorded at fair value in the financial statements, with changes in value being recorded in either net income or other comprehensive income as applicable. A 5% increase in energy prices would have decreased net income for the year ended December 31, 2008 by approximately \$15 million and other comprehensive income by \$12 million, prior to taxes. The corresponding increase in the value of the revenue or capacity being contracted, however, is not recorded in net income until subsequent periods.

The company held credit default swap contracts with an aggregate net notional amount of \$2.5 billion at December 31, 2008. The company is exposed to changes in the credit spread of the contracts' underlying reference asset. A 10 basis point increase in the credit spread of the underlying reference assets would have increased net income by \$11 million for the year ended December 31, 2008, prior to taxes.

b) Credit risk

Credit risk is the risk of loss due to the failure of a borrower or counterparty to fulfill its contractual obligations. The company's exposure to credit risk in respect of financial instruments relates primarily to counterparty obligations regarding derivative contracts, loans receivable and credit investments such as bonds and preferred shares.

The company assesses the credit worthiness of each counterparty before entering into contracts and ensures that counterparties meet minimum credit quality requirements. Management evaluates and monitors counterparty credit risk for derivative financial instruments and endeavours to minimize counterparty credit risk through diversification, collateral arrangements, and other credit risk mitigation techniques. The credit risk of derivative financial instruments is generally limited to the positive fair value of the instruments, which, in general, tends to be a relatively small proportion of the notional value. Substantially all of the company's derivative financial instruments involve either counterparties that are banks or other financial institutions in North America, the United Kingdom and Australia, or arrangements that have embedded credit risk mitigation features. The company does not expect to incur credit losses in respect of any of these counterparties. The maximum exposure in respect of loans receivables and credit investments is equal to the carrying value.

c) Liquidity risk

Liquidity risk is the risk that the company cannot meet a demand for cash or fund an obligation as it comes due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price.

To ensure the company is able to react to contingencies and investment opportunities quickly, the company maintains a high level of liquidity at the corporate level. The primary source of liquidity consists of cash and financial assets, net of deposits and other associated liabilities, and undrawn committed credit facilities.

The company is subject to the risks associated with debt financing, including the ability to refinance indebtedness at maturity. These risks are mitigated through the use of long-term debt secured by high quality assets, maintaining debt levels that are in management's opinion relatively conservative, and by diversifying maturities over an extended period of time. The company also seeks to include in its agreements terms that protect the company from liquidity issues of counterparties that might otherwise impact the company's liquidity.

20. CAPITAL MANAGEMENT

The capital of the company consists of the components of shareholders' equity in the company's consolidated balance sheet (i.e. common and preferred equity) as well as the company's capital securities, which consist of preferred shares that are convertible into common shares at the option of either the holder or the company. As at December 31, 2008, these items totalled \$6.3 billion on a book value basis (2007 – \$8.0 billion).

The company's objectives when managing this capital is to maintain an appropriate balance between holding a sufficient amount of capital to support its operations, which includes maintaining investment grade ratings at the corporate level, and providing shareholders with a prudent amount of leverage to enhance returns. Corporate leverage, which consists of corporate debt as well as subsidiary debt that is guaranteed by the company or is otherwise considered corporate in nature, totalled \$3.0 billion at December 31, 2008 (2007 – \$2.8 billion). The company monitors its capital base and leverage primarily in the context of its deconsolidated debt-to-total capitalization ratios. The ratio as at December 31, 2008 was 28% (2007 – 23%), which is within the company's target of between 20% and 30% on a book value basis.

The consolidated capitalization of the company includes the capital and financial obligations of consolidated entities, including long-term property specific financings, subsidiary borrowings, capital securities as well as common and preferred equity and equity held by other investors in consolidated entities. The capital in these entities is managed at the entity level with oversight by management of the company. The capital is typically managed with the objective of maintaining investment grade levels in most circumstances and is, except limited and carefully managed circumstances, without any recourse to the company. Management of the company also takes into consideration capital requirements of consolidated and non-consolidated entities that it has interests in when considering the appropriate level of capital and liquidity on a deconsolidated basis.

The company is subject to limited covenants in respect of its corporate debt and is in full compliance with all such covenants as at December 31, 2008. The company and its consolidated entities are also in compliance with all covenants and other capital requirements arising from regulatory or contractual obligations of material consequence to the company.

21. REVENUES LESS DIRECT OPERATING COSTS

Direct operating costs include all attributable expenses except interest, depreciation and amortization, taxes, other provisions and non-controlling interests in income. The details are as follows:

(MILLIONS)	2008			2007		
	Revenue	Expenses	Net	Revenue	Expenses	Net
Commercial properties	\$ 2,761	\$ 930	\$ 1,831	\$ 2,851	\$ 1,303	\$ 1,548
Power generation	1,286	400	886	959	348	611
Infrastructure	455	259	196	599	309	290
Development and other properties	3,689	3,449	240	1,802	1,384	418
Specialty funds	2,090	1,786	304	1,246	876	370
	\$ 10,281	\$ 6,824	\$ 3,457	\$ 7,457	\$ 4,220	\$ 3,237

22. NON-CONTROLLING INTERESTS IN INCOME

Non-controlling interests of others in income is segregated into the non-controlling share of income before certain items and their share of those items, which include depreciation and amortization, income taxes and other provisions.

(MILLIONS)	2008	2007
Non-controlling interests' share of income prior to the following	\$ 791	\$ 636
Non-controlling interests' share of depreciation and amortization, and future income taxes and other provisions	(430)	(538)
Non-controlling interests in income	\$ 361	\$ 98
Distributed as recurring dividends		
Preferred	\$ 2	\$ 5
Common	203	169
Undistributed (Overdistributed)	156	(76)
Non-controlling interests in income	\$ 361	\$ 98

23. INCOME TAXES

(MILLIONS)	2008	2007
Current	\$ (7)	\$ 68
Future	(461)	88
Current and future income tax (recovery) expense	\$ (468)	\$ 156

Future income tax assets relate primarily to non-capital losses available to reduce taxable income which may arise in the future. The company and its Canadian subsidiaries have future income tax assets of \$215 million (2007 – \$359 million) that relate to

non-capital losses which expire over the next 20 years, and \$82 million (2007 – \$105 million) that relate to capital losses which have no expiry date. The company's U.S. subsidiaries have future income tax assets of \$177 million (2007 – \$272 million) that relate to net operating losses which expire over the next 20 years. The company's international subsidiaries have future income tax assets of \$237 million (2007 – \$196 million) that relate to operating losses which generally have no expiry date. The amount of non-capital and capital losses and deductible temporary differences for which no future income tax assets have been recognized is approximately \$3,004 million (2007 – \$2,825 million). The future income tax liabilities represent the cumulative amount of income tax payable on the differences between the book values and the tax values of the company's assets and liabilities at the rates expected to be effective at the time the differences are anticipated to reverse. The future income tax liabilities relate primarily to differences between book values and tax values of property, plant and equipment due to different depreciation rates for accounting and tax purposes. The future income tax assets and liabilities are recorded in accounts receivable and other and accounts payable and other liabilities on the balance sheet.

The following table reflects the company's effective tax rate at December 31, 2008 and 2007:

	2008	2007
Statutory income tax rate	33%	33%
Increase (reduction) in rate resulting from		
Portion of gains not subject to tax	(6)	(13)
Lower income tax rates in other jurisdictions	(45)	(8)
Change in tax rates on temporary differences	(99)	(7)
Derecognition of future tax assets/(liabilities)	7	(9)
Foreign exchange gain and losses	(27)	9
Non-recognition of the benefit of current year's tax losses	27	2
Other	13	7
Effective income tax rate	(97)%	14%

24. EQUITY ACCOUNTED LOSS FROM INVESTMENTS

Equity accounted loss from investments includes the following:

(MILLIONS)	2008	2007
Norbord	\$ (46)	\$ (17)
Fraser Papers ¹	—	(23)
Stelco Inc. ²	—	(32)
Total	\$ (46)	\$ (72)

¹ During 2007, the company increased its ownership in Fraser Papers to 56% and started to account for the investment on a consolidated basis

² During 2007, the company sold its 23% common equity interest in Stelco

25. JOINT VENTURES

The following amounts represent the company's proportionate interest in incorporated and unincorporated joint ventures that are reflected in the company's accounts:

(MILLIONS)	2008	2007
Assets	\$ 5,615	\$ 4,841
Liabilities	2,912	2,287
Operating revenues	693	724
Operating expenses	454	408
Net income	92	285
Cash flows from operating activities	104	283
Cash flows (used in) from investing activities	(145)	74
Cash flows from (used in) financing activities	105	(189)

26. POST-EMPLOYMENT BENEFITS

The company offers pension and other post employment benefit plans to employees of certain of its subsidiaries. The company's obligations under its defined benefit pension plans are determined periodically through the preparation of actuarial valuations. The benefit plans' expenses for 2008 were \$13 million (2007 – \$2 million). The discount rate used was 6% (2007 – 6%) with an increase in the rate of compensation of 3% (2007 – 4%) and an investment rate of 7% (2007 – 8%).

(MILLIONS)	2008	2007
Plan assets	\$ 983	\$ 688
Less accrued benefit obligation:		
Defined benefit pension plan	(1,094)	(586)
Other post-employment benefits	(62)	(62)
Net (liability) asset	(173)	40
Less: Unamortized transitional obligations and net actuarial losses	291	14
Accrued benefit asset	\$ 118	\$ 54

27. SUPPLEMENTAL CASH FLOW INFORMATION

(MILLIONS)	2008	2007
Corporate borrowings		
Issuances	\$ 150	\$ 474
Repayments	(300)	(165)
Net commercial paper and bank borrowings issued	483	167
Net	\$ 333	\$ 476
Property-specific mortgages		
Issuances	\$ 4,620	\$ 4,113
Repayments	(5,642)	(1,629)
Net	\$ (1,022)	\$ 2,484
Other debt of subsidiaries		
Issuances	\$ 1,379	\$ 2,897
Repayments	(1,879)	(1,073)
Net	\$ (500)	\$ 1,824
Common shares		
Issuances	\$ 32	\$ 44
Repayments	(281)	(165)
Net	\$ (249)	\$ (121)
Commercial property		
Proceeds of dispositions	\$ 768	\$ 328
Investments	(695)	(5,468)
Net	\$ 73	\$ (5,140)
Power		
Proceeds of dispositions	\$ —	\$ —
Investments	(529)	(452)
Net	\$ (529)	\$ (452)
Infrastructure		
Proceeds of dispositions	\$ 613	\$ —
Investments	(252)	(1,330)
Net	\$ 361	\$ (1,330)
Development and other properties		
Proceeds of dispositions	\$ 216	\$ 127
Investments	(915)	(785)
Net	\$ (699)	\$ (658)
Securities		
Securities sold	\$ 604	\$ 128
Securities purchased	(319)	(552)
Loans collected	781	707
Loans advanced	(940)	(811)
Net	\$ 126	\$ (528)
Financial assets		
Securities sold	\$ 665	\$ 1,396
Securities purchased	(346)	(760)
Net	\$ 319	\$ 636

Cash taxes paid were \$78 million (2007 – \$103 million) and are included in current income taxes. Cash interest paid totalled \$2,163 million (2007 – \$1,686 million). Sustaining capital expenditures in the company's power generating operations were \$70 million (2007 – \$50 million), in its property operations were \$48 million (2007 – \$45 million) and in its transmission operations were \$9 million (2007 – \$10 million).

28. SEGMENTED INFORMATION

The company's presentation of reportable segments is based on how management has organized the business in making operating and capital allocation decisions and assessing performance. The company has five reportable segments:

- commercial properties operations, which are principally commercial office properties and retail properties, located primarily in major North American, Brazilian, and Australian cities;
- power generation operations, which are predominantly hydroelectric power generating facilities on river systems in North America and Brazil;
- infrastructure operations, which are predominantly timberlands and electrical transmission and distribution systems. The company's timberland operations are located in North America and Brazil. The electrical transmission and distribution systems are located in Northern Ontario and Chile;
- development and other properties operations, which are principally commercial and residential development, opportunistic investing and homebuilding operations, located primarily in major North American, Brazilian and Australian cities; and
- specialty funds, which include the company's bridge lending, real estate finance and restructuring funds, and which are managed by the company for itself and for its institutional partners.

Non-operating assets and related revenues, cash flows and income are presented as financial assets and other.

Revenue, net income and assets by reportable segments are as follows:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008			2007		
	Revenue	Net Income	Assets	Revenue	Net Income	Assets
Commercial properties	\$ 3,075	\$ 203	\$ 23,699	\$ 2,891	\$ 24	\$ 23,571
Power generation	1,286	328	6,778	971	106	7,106
Infrastructure	616	37	4,414	622	4	4,230
Development and other properties	3,654	(7)	9,822	1,751	138	12,115
Specialty funds	2,139	126	3,943	1,368	187	2,676
Cash, financial assets, fee revenues and other	2,098	(38)	4,955	1,740	328	5,899
	\$ 12,868	\$ 649	\$ 53,611	\$ 9,343	\$ 787	\$ 55,597

Revenue and assets by geographic segments are as follows:

AS AT AND FOR THE YEARS ENDED DECEMBER 31 (MILLIONS)	2008		2007	
	Revenue	Assets	Revenue	Assets
United States	\$ 5,617	\$ 27,220	\$ 4,844	\$ 27,156
Canada	3,005	11,755	2,604	12,248
Australia	1,826	6,031	622	8,323
Brazil	1,092	5,749	636	5,648
Europe	543	1,901	251	1,154
Other	785	955	386	1,068
	\$ 12,868	\$ 53,611	\$ 9,343	\$ 55,597

29. OTHER INFORMATION

Commitments, Guarantees and Contingencies

In the normal course of business, the company and its subsidiaries enter into contractual obligations which include commitments to provide bridge financing, and letters of credit and guarantees provided in respect of power sales contracts and reinsurance obligations. At the end of 2008, the company and its subsidiaries had \$1,269 million (2007 – \$1,068 million) of such commitments outstanding of which \$211 million (2007 – \$95 million) is included on liabilities in the consolidated balance sheets.

In addition, the company and its consolidated subsidiaries execute agreements that provide for indemnifications and guarantees to third parties in transactions or dealings such as business dispositions, business acquisitions, sales of assets, provision of services, securitization agreements, and underwriting and agency agreements. The company has also agreed to indemnify its directors and certain of its officers and employees. The nature of substantially all of the indemnification undertakings prevents the company from making a reasonable estimate of the maximum potential amount the company could be required to pay third parties, as in most cases the agreements do not 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. Neither the company nor its consolidated subsidiaries have made significant payments in the past nor do they expect at this time to make any significant payments under such indemnification agreements in the future.

The company periodically enters into joint venture, consortium or other arrangements that have contingent liquidity rights in favour of the company or its counterparties. These include buy-sell arrangements, registration rights and other customary arrangements. These agreements generally have embedded protective terms that mitigate the risk to us. The amount, timing and likelihood of any payments by the company under these arrangements is in most cases dependent on either further contingent events or circumstances applicable to the counterparty and therefore cannot be determined at this time.

The company and its subsidiaries are contingently liable with respect to litigation and claims that arise in the normal course of business.

The company has acquired \$500 million of insurance for damage and business interruption costs sustained as a result of an act of terrorism. However, a terrorist act could have a material effect on the company's assets to the extent damages exceed the coverage.

The company has reviewed its loan agreements and believes it is in compliance, in all material respects, with the contractual obligations therein.

The company, through its subsidiaries within the residential properties operations, is contingently liable for obligations of its associates in its land development joint ventures. In each case, all of the assets of the joint venture are available first for the purpose of satisfying these obligations, with the balance shared among the participants in accordance with predetermined joint venture arrangements.

Insurance

The company conducts insurance operations as part of its asset management activities. As at December 31, 2008, the company held insurance assets of \$309 million (2007 – \$581 million) in respect of insurance contracts that are accounted for using the deposit method which were offset in each year by an equal amount of reserves and other liabilities. During 2008, net underwriting losses on reinsurance operations were \$18 million (2007 income of \$67 million) representing \$363 million (2007 – \$544 million) of premium and other revenues offset by \$381 million (2007 – \$477 million) of reserves and other expenses.

Five Year Financial Review

AS AT AND FOR THE YEARS ENDED DECEMBER 31

(MILLIONS, EXCEPT PER SHARE AMOUNTS; UNAUDITED)

	2008	2007	2006	2005	2004
Per Common Share (fully diluted)					
Book value – actual	\$ 8.93	\$ 11.64	\$ 9.37	\$ 7.87	\$ 5.67
– Underlying value	20.67	—	—	—	—
– Underlying value pre-tax	24.37	—	—	—	—
Cash flow from operations	2.33	3.11	2.95	1.46	1.03
Cash return on book equity	23%	30%	34%	21%	19%
Net income	\$ 1.02	\$ 1.24	\$ 1.90	\$ 2.72	\$ 0.90
Market trading price – NYSE	\$ 15.27	\$ 35.67	\$ 32.12	\$ 22.37	\$ 16.01
Dividends paid	\$ 1.45 ¹	\$ 0.47	\$ 0.39	\$ 0.26	\$ 0.24
Common shares outstanding					
Basic	572.6	583.6	581.8	579.6	582.1
Diluted	600.3	611.0	610.8	608.0	611.3
Total (millions)					
Total assets under management	\$ 78,697	\$ 94,340	\$ 71,121	\$ 49,700	\$ 27,146
Consolidated balance sheet assets	53,611	55,597	40,708	26,058	20,007
Corporate borrowings	2,284	2,048	1,507	1,620	1,675
Non-recourse borrowings					
Property-specific mortgages	22,889	21,644	17,148	8,756	6,045
Other debt of subsidiaries	5,102	7,076	4,153	2,510	2,373
Common equity – book value	4,918 ²	6,644	5,395	4,514	3,277
– Underlying value ³	11,931	—	—	—	—
– Underlying value, pre-tax ³	14,151	—	—	—	—
Revenues	12,868	9,343	6,897	5,220	3,867
Operating income	4,809	4,509	3,776	2,319	1,793
Cash flow from operations	1,423	1,907	1,801	908	626
Net income	649	787	1,170	1,662	555

¹ Includes Brookfield Infrastructure special dividend of \$0.94

² Reduction reflects distribution of Brookfield Infrastructure

³ Reflects fair value prepared in accordance with procedures and assumptions expected to be utilized to prepare the company's January 1, 2009 IFRS balance sheet

Corporate Governance

Management and the Board of Directors are committed to working together to achieve strong and effective corporate governance. Our Board of Directors is of the view that our corporate governance policies and practices and our disclosure in this regard are appropriate, effective and consistent with the guidelines established by Canadian and U.S. securities regulators. We continue to review our corporate governance policies and practices in relation to evolving legislation, guidelines and best practices.

Our Statement of Corporate Governance Practices is set out in full in the Management Information Circular mailed each year to all our shareholders along with the Notice of our Annual Meeting. This Statement is also available on our web site, **www.brookfield.com**, at “About Brookfield / Corporate Governance.”

You can also access the following documents referred to in the Statement on our web site – our Board of Directors Charter, the Charter of Expectations for Directors, the Charters of the Board’s three Standing Committees (Audit, Governance & Nominating and Management Resources & Compensation), Board Position Descriptions, our Code of Business Conduct and our Corporate Disclosure Policy. We encourage you to review these materials.

Sustainable Development

Management and the Board of Directors are committed to the principle that our business decisions will consider a broad range of issues, including the long-term sustainability of our local communities in which we operate, taking into account current and future environmental, safety, health and economic considerations. The review and improvement of our sustainability practices is an ongoing process that we take very seriously throughout our organization.

Environmental initiatives across our operations include energy reduction, water conservation, recycling, air quality standards, wildlife preservation, timber harvesting techniques and erosion control. We believe that these initiatives will benefit the company over the long term from an economic perspective by increasing competitiveness and strengthening the local communities in which we operate. While an appropriate balance is sometimes difficult to achieve, the initiatives we undertake and the investments we make in building our company are guided by our core set of values around sustainable development.

Our renewable energy business is focused on hydroelectricity and wind power generation, while our office properties contain building features, systems and programs that foster environmental responsibility, cost and energy savings for tenants, and the health and safety of all those who work at and visit our properties. We implement comprehensive environmental initiatives in existing properties as well as new development projects to ensure industry standards are achieved and exceeded. For example, our most recent office development, the Bay Adelaide Centre in Toronto, is being built to a Leadership in Energy and Environmental Design (“LEED”) Gold standard. The LEED® Green Building Rating System is the internationally accepted scorecard for sustainable sites, water efficiency, energy and atmosphere, materials and resources, and indoor environmental quality.

Shareholder Information

Shareholder Enquiries

Shareholder enquiries are welcomed and should be directed to our Investor Relations group at 416-363-9491 or at the email below. Alternatively shareholders may contact the company at its administrative head office:

Brookfield Asset Management Inc.

Suite 300, Brookfield Place, Box 762, 181 Bay Street
Toronto, Ontario M5J 2T3

Telephone: 416-363-9491

Facsimile: 416-365-9642

Web Site: www.brookfield.com

E-Mail: inquiries@brookfield.com

Shareholder enquiries relating to dividends, address changes and share certificates should be directed to the company's Transfer Agent:

CIBC Mellon Trust Company

P.O. Box 7010, Adelaide Street Postal Station
Toronto, Ontario M5C 2W9

Telephone: 416-643-5500 or

1-800-387-0825 (Toll free throughout North America)

Facsimile: 416-643-5501

Web Site: www.cibcmellon.com

E-Mail: inquiries@cibcmellon.com

Investor Relations and Communications

We are committed to informing our shareholders of our progress through a comprehensive communications program which includes publication of materials such as our annual report, quarterly interim reports and press releases for material information. We also maintain a web site that provides ready access to these materials, as well as statutory filings, stock and dividend information and other presentations.

Meeting with shareholders is an integral part of our communications program. Directors and management meet with Brookfield's shareholders at our annual meeting and are available to respond to questions at any time. Management is also available to investment analysts, financial advisors and media to ensure that accurate information is available to investors. All materials distributed at any of these meetings are posted on the company's web site.

The text of the company's 2008 Annual Report is available in French on request from the company and is filed with and available through SEDAR at www.sedar.com.

Annual Meeting of Shareholders

The company's 2009 Annual and Special Meeting of Shareholders will be held at 9:00 a.m. on Tuesday, May 5, 2009 at the Auditorium, 300 Madison Avenue, New York, New York, U.S.A. and will be webcast through www.brookfield.com.

Stock Exchange Listings

	Symbol	Stock Exchange
Class A Common Shares	BAM	New York
	BAM.A	Toronto
	BAMA	Euronext Amsterdam
Class A Preference Shares		
Series 2	BAM.PR.B	Toronto
Series 4	BAM.PR.C	Toronto
Series 8	BAM.PR.E	Toronto
Series 9	BAM.PR.G	Toronto
Series 10	BAM.PR.H	Toronto
Series 11	BAM.PR.I	Toronto
Series 12	BAM.PR.J	Toronto
Series 13	BAM.PR.K	Toronto
Series 14	BAM.PR.L	Toronto
Series 17	BAM.PR.M	Toronto
Series 18	BAM.PR.N	Toronto
Series 21	BAM.PR.O	Toronto

Dividend Reinvestment Plan

Registered holders of Class A Common Shares who are resident in Canada may elect to receive their dividends in the form of newly issued Class A Common Shares at a price equal to the weighted average price at which the shares traded on the Toronto Stock Exchange during the five trading days immediately preceding the payment date of such dividends.

The Dividend Reinvestment Plan allows current shareholders to acquire additional Class A Common Shares in the company without payment of commissions. Further details on the Dividend Reinvestment Plan and a Participation Form can be obtained from our administrative head office, our transfer agent or from our web site.

Dividend Record and Payment Dates

	Record Date	Payment Date
Class A Common Shares ¹	First day of February, May, August and November	Last day of February, May, August and November
Class A Preference Shares ¹		
Series 2, 4, 10, 11, 12, 13, 17, 18 and 21	15th day of March, June, September and December	Last day of March, June, September and December
Series 8 and 14	Last day of each month	12th day of following month
Series 9	15th day of January, April, July and October	First day of February, May, August and November

¹ All dividend payments are subject to declaration by the Board of Directors

Board of Directors and Officers

BOARD OF DIRECTORS

Robert J. Harding, F.C.A.

Chairman

Brookfield Asset Management Inc.

Jack L. Cockwell

Group Chairman

Brookfield Asset Management Inc.

Marcel R. Coutu

President and Chief Executive Officer

Canadian Oil Sands Limited

The Hon. J. Trevor Eyton, O.C.

Member of the Senate of Canada

J. Bruce Flatt

Senior Managing Partner and CEO

Brookfield Asset Management Inc.

James K. Gray, O.C.

Founder and former Chairman

and Chief Executive Officer

Canadian Hunter Exploration Ltd.

Maureen Kempston Darkes, O.C., O.Ont.

Group Vice President and President

Latin America, Africa and Middle East

General Motors Corporation

David W. Kerr

Corporate Director

Lance Liebman

Director

American Law Institute

Philip B. Lind, C.M.

Vice-Chairman

Rogers Communications Inc.

G. Wallace F. McCain, O.C., C.C., O.N.B.

Chairman

Maple Leaf Foods Inc.

The Hon. Frank J. McKenna, P.C., O.C., O.N.B.

Deputy Chair

TD Bank Financial Group

Dr. Jack M. Mintz

Palmer Chair in Public Policy

University of Calgary

Patricia M. Newson, C.A.

President and Chief Executive Officer

AltaGas Utility Group Inc.

James A. Pattison, O.C., O.B.C.

Chief Executive Officer

The Jim Pattison Group

George S. Taylor

Corporate Director

Details on Brookfield's Directors are provided in the Management Information Circular and on Brookfield's web site

SENIOR MANAGING PARTNERS

Barry S. Blattman

Jeffrey M. Blidner

Richard B. Clark

Steven J. Douglas

J. Bruce Flatt

Joseph S. Freedman

Harry A. Goldgut

Brian D. Lawson

Richard J. Legault

Luiz Ildefonso Lopes

Cyrus Madon

George E. Myhal

Samuel J.B. Pollock

CHAIRMEN

Gordon E. Arnell, O.C.

Ian G. Cockwell

Jack L. Cockwell

Edward C. Kress

Timothy R. Price

John E. Zuccotti

CORPORATE OFFICERS

J. Bruce Flatt

Senior Managing Partner and

Chief Executive Officer

Brian D. Lawson

Senior Managing Partner and

Chief Financial Officer

Catherine J. Johnston

Corporate Secretary



Mixed Sources
Product group from well-managed
forests, controlled sources and
recycled wood or fiber
www.fsc.org Cert no. SCS-COC-00867
© 1996 Forest Stewardship Council

Brookfield incorporates sustainable development practices within our corporation. This document was printed in Canada using vegetable based inks on FSC certified stock.

CORPORATE OFFICES

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F 212-417-7196

Toronto – Canada

Brookfield Place, Suite 300
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181 Bay Street, Box 762
Toronto, Ontario M5J 2T3
T 416-363-9491
F 416-365-9642

REGIONAL OFFICES

Sydney – Australia

Level 1
1 Kent Street
Sydney, NSW 2000
T 62-2-9256-5000
F 62-2-9256-5001

London – United Kingdom

40 Berkeley Square
London W1J 5AL
United Kingdom
T 44 (0) 20-7659-3500
F 44 (0) 20-7659-3501

Hong Kong

Lippo Centre, Tower Two
26/F, 2601
89 Queensway, Hong Kong
T 852-2810-4538
F 852-2810-7083

São Paulo – Brazil

Brascan Century Plaza
Rua Joaquim Floriano,
466 Edificio Corporate, 10º Andar,
Conjunto 1004
São Paulo, SP Brasil
CEP: 04534-002
T 55 (11) 3707-6700
F 55 (11) 3078-4249

Dubai – UAE

Level 12, Al Attar Business Tower
Sheikh Zayed Road
Dubai, UAE
T 971-4-3158-500
F 971-4-3158-600

Appendix I



BOARD OF DIRECTORS

Conquest Room
InterContinental Hotel, Toronto Centre
225 Front Street
Toronto, Ontario

Tuesday, June 23, 2009

AGENDA ITEM #7.2

DRAFT RESOLUTION

FORTISONTARIO INC. ACQUISITION OF GREAT LAKES POWER DISTRIBUTION INC.

WHEREAS Fortis Inc. (the "Corporation") owns all of the issued and outstanding shares of FortisOntario Inc. ("FortisOntario");

AND WHEREAS FortisOntario is proposing to acquire all of the issued and outstanding common shares (the "Shares") of Great Lakes Power Distribution Inc. ("GLPD") for a purchase price expected not to exceed \$85,000,000, inclusive of adjustments and transaction costs ("Purchase Price") pursuant to a share purchase agreement (the "Share Purchase Agreement") between FortisOntario, Brookfield Renewable Power Inc. ("Brookfield") and the Corporation as guarantor of the due and punctual performance of the obligations of FortisOntario including payment of the purchase price and adjustments (the "Share Purchase Agreement");

AND WHEREAS sections A4 and A5 of the Authorizations Guidelines for the Board of Directors of the Corporation provides that the Board will review and approve the procurement, allocation and disposition of corporate resources in the annual Business Plan, or if not contemplated in the Business Plan in an amount in excess of \$20,000,000 and review and approve direct investment in subsidiaries as a precondition to the implementation thereof and ;

AND WHEREAS subsections 198(1) and (5) of the *Corporations Act* (Newfoundland and Labrador) (the "Act") provide that a director or an officer of a corporation shall disclose to the corporation, or request to have entered in the minutes of meetings of directors, the nature and extent of his or her interest where the director or officer:

- (a) is a party to a material contract or proposed material contract with the corporation; or

- (b) is a director or an officer of or has a material interest in a person who is a party to a material contract or proposed material contract with the corporation,

and shall not vote on any resolution to approve the contract or transaction unless the contract or transaction is, among other things, one with an affiliate;

AND WHEREAS the Corporation and FortisOntario are affiliated within the meaning of the Act;

AND WHEREAS Peter E. Case is a director, Geoffrey F. Hyland is a director and Barry V. Perry is an officer, of the Corporation, and have requested to have entered in the minutes of the meeting that they are to be regarded as interested in the entering into of the Share Purchase Agreement and the provision of the Guarantee by the Corporation by virtue of them being a director, and in the case of Peter E. Case, a director and non-executive officer, of FortisOntario;

NOW THEREFORE BE IT RESOLVED THAT:

1. The Corporation approve the acquisition of GLPD by FortisOntario for the Purchase Price and provide to FortisOntario such funding of the Purchase Price, by way of debt or equity investment, in such amount and form, not to exceed the Purchase Price as the Vice President, Finance and Chief Financial Officer may approve;
2. The Corporation be and is hereby authorized to execute, deliver and perform its obligations under the Share Purchase Agreement providing for (i) the acquisition by FortisOntario of the common shares of GLPD for the Purchase Price and (ii) the Guarantee by the Corporation to Brookfield of the obligations of FortisOntario, upon such terms and conditions as the officers of the Corporation executing the Share Purchase Agreement in accordance with this resolution may determine appropriate;
3. any two officers of the Corporation be and are hereby authorized and directed, for and in the name of and on behalf of the Corporation, to execute (whether under the corporate seal of the Corporation or otherwise) and to deliver the Share Purchase Agreement, with all such changes as such officers may determine appropriate, such determination to be conclusively evidenced by the execution and delivery of the Share Purchase Agreement by such officers on behalf of the Corporation; and
4. any one officer of the Corporation be and is hereby authorized, for and in the name of and on behalf of the Corporation, to execute (whether under the corporate seal of the Corporation or otherwise) and to deliver all such agreements, instruments, certificates and other documents and to do all such other acts and things as such officer may in his discretion determine to be necessary, advisable or useful for the purpose of giving effect to the provisions of this resolution the execution of any such agreement, instrument, certificate or other document or doing of any such acts and things to constitute conclusive evidence of such determination.