No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. ***Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada.*** *Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the Corporation at Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 (telephone (709) 737-2800) or by accessing the Corporation's disclosure documents available through the Internet on the Canadian System for Electronic Document Analysis and Retrieval which can be accessed at www.sedar.com. For the purpose of the province of Québec, this simplified prospectus contains information to be completed by consulting the permanent information record. A copy of the permanent information record may be obtained from the Secretary of the Corporation at Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 (telephone (709) 737-2800). The securities being offered under this short form prospectus have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws, and, except in limited circumstances, will not be offered or sold within the United States to or for the account or benefit of United States persons. See ''Plan of Distribution''.*

New Issue **September 29, 2003**

SHORT FORM PROSPECTUS

FORTIS INC.

$350,205,000

6,310,000 Subscription Receipts, each representing the right to receive one Common Share

Fortis Inc. (''Fortis'' or the ''Corporation'') is hereby qualifying for distribution (the ''Offering'') 6,310,000 subscription receipts (the ''Subscription Receipts''), each of which will entitle the holder thereof to receive, upon satisfaction of the Release Conditions (as defined below), and without payment of additional consideration, one common share of Fortis (a ''Common Share''). The gross proceeds from the sale of the Subscription Receipts (the ''Escrowed Funds'') will be held by Computershare Trust Company of Canada, as escrow agent (the ''Escrow Agent'') and invested in short-term interest bearing or discount debt obligations issued or guaranteed by the Government of Canada or a province, or one or more of the five largest Canadian chartered banks, provided that such obligation is rated at least R1 (middle) by Dominion Bond Rating Service Limited or an equivalent rating service, pending receipt by the Corporation of all regulatory and government approvals required to finalize the acquisition by the Corporation of all of the issued and outstanding shares of Aquila Networks Canada (Alberta) Ltd. (the ''Alberta Utility'') and Aquila Networks Canada (British Columbia) Ltd. (the ''B.C. Utility'') (the ''Acquisition''), including those of the Alberta Energy and Utilities Board (the ''AEUB'') and the British Columbia Utilities Commission (the ''BCUC''), and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition as itemized in the Acquisition Agreements (as defined below) (collectively, the ''Release Conditions''). See ''The Acquisition'' and ''Details of the Offering''.

If the Release Conditions are satisfied prior to 5:00 p.m. (Toronto time) on June 30, 2004, the Corporation will forthwith execute and deliver a notice of satisfaction and will issue and deliver to the Escrow Agent one Common Share for each Subscription Receipt then outstanding. The Common Shares will be available for delivery commencing on the second business day after the delivery of such notice. The holders of Subscription Receipts will receive, without payment of any additional consideration, one Common Share for each Subscription Receipt held plus an amount equal to the dividends declared on the Common Shares by the Corporation to holders of record on a date during the period from the Closing Date (as defined below) to the date of issuance of the Common Shares in respect of the Subscription Receipts. Forthwith upon the Release Conditions being satisfied and the required notice being delivered to the Escrow Agent, the Escrowed Funds, together with interest earned and income generated thereon, will be released to Fortis. In the event that the Release Conditions are not satisfied prior to 5:00 p.m. (Toronto time) on June 30, 2004 or, if either of the Acquisition Agreements is terminated prior to such time (in either case, the ''Termination Time''), holders of Subscription Receipts shall, commencing on the second business day following the Termination Time, be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* entitlement to interest earned or income generated on such amount. See ''Details of the Offering''.

There is currently no market through which the Subscription Receipts may be sold and purchasers may not be able to resell securities purchased under this short form prospectus (the ''Prospectus'').

The Toronto Stock Exchange (the ''TSX'') has conditionally approved the listing of the Subscription Receipts. Listing will be subject to the Corporation fulfilling all of the listing requirements of the TSX on or before December 15, 2003. The Corporation's outstanding Common Shares are listed on the TSX under the symbol ''FTS''. On September 26, 2003, the closing price of the Common Shares on the TSX was $55.50.

An investment in the Subscription Receipts, and the Common Shares issuable upon the exchange thereof, involves certain risks that should be considered by a prospective purchaser. See ''Risk Factors''.

Price: $55.50 per Subscription Receipt

	Price to the Public	Underwriters' Fee (1)	Net Proceeds to the Corporation (2)
Per Subscription Receipt	$55.50	$2.22	$53.28
Total	$350,205,000	$14,008,200	$336,196,800

(1) One-half of the Underwriters' fee is payable at the closing of the Offering. The other half of the Underwriters' fee is payable only if the Release Conditions have been satisfied prior to the Termination Time and the required notice has been delivered to the Escrow Agent. See ''Plan of Distribution''.

(2) Net proceeds to the Corporation exclude any interest earned and income generated on the Escrowed Funds and are calculated before deducting the expenses of the Offering, estimated at $800,000, which, together with the Underwriters' fee, will be paid out of the general funds of Fortis. See ''Plan of Distribution''.

Scotia Capital Inc. (''Scotia Capital''), BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc. and Beacon Securities Limited are acting as underwriters (the ''Underwriters'') of the Offering. The Underwriters, as principals, conditionally offer the Subscription Receipts, subject to prior sale, if, as and when issued, sold and delivered by the Corporation to, and accepted by, the Underwriters in accordance with the terms and conditions contained in the Underwriting Agreement referred to under ''Plan of Distribution'' and subject to the approval of certain legal matters on behalf of the Corporation by Davies Ward Phillips & Vineberg LLP, Toronto and Curtis, Dawe, St. John's and on behalf of the Underwriters by Stikeman Elliott LLP, Toronto.

Each of Scotia Capital, BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc. and TD Securities Inc. are affiliates of Canadian chartered banks that are part of a syndicate of banks that have agreed to extend credit facilities to the Corporation in connection with financing the Acquisition. Scotia Capital has agreed to act as the sole lead arranger and book runner in connection with this financing and is receiving a fee for its role as financial advisor to Fortis in connection with the Acquisition. Consequently, the Corporation may be considered a ''connected issuer'' of these Underwriters within the meaning of applicable securities legislation. See ''Plan of Distribution''.

Subscriptions for the Subscription Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of the Offering will take place on or about October 8, 2003 (the ''Closing Date''), or such other date as may be agreed upon by the Corporation and the Underwriters, but not later than November 7, 2003. A book entry only certificate representing the Subscription Receipts distributed hereunder will be issued in registered form only to The Canadian Depository for Securities Limited (''CDS'') or its nominee and will be deposited with CDS on the Closing Date. The Corporation understands that a purchaser of Subscription Receipts will receive only a customer confirmation from the registered dealer who is a CDS participant (''CDS Participant'') from or through whom the Subscription Receipts are purchased. See ''Details of the Offering''.

The Prospectus includes financial statements of the Alberta Utility for the year ended December 31, 2001 and the B.C. Utility for the years ended December 31, 2001 and 2000 that were audited and reported on by Arthur Andersen LLP (''Arthur Andersen''). We have not obtained the consent of Arthur Andersen to the use of its audit report in respect of these financial statements. Arthur Andersen's consent was not obtained because on June 3, 2002, Arthur Andersen ceased to practice public accounting. Because Arthur Andersen has not provided this consent, purchasers of Subscription Receipts pursuant to the Prospectus will not have the statutory right of action for damages against Arthur Andersen as prescribed by applicable securities legislation with respect to these financial statements. In addition, Arthur Andersen may not have sufficient assets available to satisfy any judgments against it. See ''Risk Factors — Arthur Andersen'' and ''Statutory Rights of Withdrawal and Rescission''.

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DOCUMENTS INCORPORATED BY REFERENCE

The disclosure documents of the Corporation listed below and filed with the appropriate securities commissions or similar regulatory authorities in each of the provinces of Canada are specifically incorporated by reference into and form an integral part of the Prospectus:

(a) Annual Information Form dated April 15, 2003;

(b) Audited comparative consolidated financial statements for the years ended December 31, 2002 and 2001 together with the notes thereto and the auditors' report thereon as contained in the Corporation's 2002 Annual Report;

(c) Management Discussion and Analysis of financial condition and results of operations contained in the Corporation's 2002 Annual Report;

(d) Management Information Circular dated March 31, 2003 prepared in connection with the Corporation's annual meeting of shareholders held on May 14, 2003, excluding those portions thereof which appear under the headings ''Performance Chart'', ''Report on Corporate Governance'' and ''Report on Executive Compensation'';

(e) Material Change Report dated May 20, 2003 describing the entering into of an agreement between the Corporation and a syndicate of underwriters led by Scotia Capital in respect of the offering of first preference shares, series C of the Corporation;

(f) Unaudited comparative financial statements for the three and six-month periods ended June 30, 2003 and 2002;

(g) Interim Management Discussion and Analysis of financial condition and results of operations of the Corporation for the three and six-month periods ended June 30, 2003 and 2002; and

(h) Material Change Report dated September 16, 2003 announcing the entering into by the Corporation of agreements to acquire all of the shares of the Alberta Utility and the B.C. Utility from two indirect subsidiaries of Aquila, Inc. for aggregate consideration of $1.36 billion.

Any document of the type referred to in the preceding paragraph and any material change report (excluding confidential reports) subsequently filed by the Corporation with such securities commissions or regulatory authorities after the date of the Prospectus, and prior to the termination of the Offering, shall be deemed to be incorporated by reference into the Prospectus.

Any statement contained in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded for purposes of the Prospectus to the extent that a statement contained herein, or in any other subsequently filed document which also is incorporated or is deemed to be incorporated by reference herein, modifies or supersedes such statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement will not be deemed an admission for any purpose that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of the Prospectus.

Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of the Corporation at Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2 (telephone (709) 737-2800). These documents are also available through the Internet on the Canadian System for Electronic Document Analysis and Retrieval (''SEDAR'') which can be accessed at www.sedar.com. The Corporation's filings available through SEDAR are not incorporated by reference in the Prospectus except as specifically set out herein.

ELIGIBILITY FOR INVESTMENT

In the opinion of Davies Ward Phillips & Vineberg LLP, counsel to the Corporation, and Stikeman Elliott LLP, counsel to the Underwriters, the Subscription Receipts and the Common Shares issuable on the exchange of the Subscription Receipts, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) (the ''Tax Act'') for a trust governed by a registered retirement savings plan, registered retirement income fund, deferred profit sharing plan or registered education savings plan. The Subscription Receipts and the Common Shares, if issued on the date hereof, would not constitute ''foreign property'' for the purposes of Part XI of the Tax Act.

DEFINED TERMS

For an explanation of certain terms and abbreviations used in the Prospectus, reference is made to the ''Glossary of Terms''.

SUMMARY

The following information is a summary only and is to be read in conjunction with, and is qualified in its entirety by, the more detailed information appearing elsewhere in the Prospectus and in the documents incorporated by reference herein.

The Offering

Issuer:	Fortis Inc. (''Fortis'' or the ''Corporation'').
Offering:	6,310,000 subscription receipts (the ''Subscription Receipts''), each representing the right to receive one common share of Fortis (a ''Common Share'').
Amount:	$350,205,000.
Price:	$55.50 per Subscription Receipt.
Date of Closing:	On or about October 8, 2003.
Escrow of Proceeds:	The gross proceeds from the sale of the Subscription Receipts (the ''Escrowed Funds'') will be held by Computershare Trust Company of Canada, as escrow agent (the ''Escrow Agent'') and invested in short-term interest bearing or discount debt obligations issued or guaranteed by the Government of Canada or a province, or one or more of the five largest Canadian chartered banks, provided that such obligation is rated at least R1 (middle) by Dominion Bond Rating Service Limited or an equivalent rating service, pending receipt by the Corporation of all regulatory and government approvals required to finalize the acquisition by the Corporation of all of the issued and outstanding shares of Aquila Networks Canada (Alberta) Ltd. (the ''Alberta Utility'') and Aquila Networks Canada (British Columbia) Ltd. (the ''B.C. Utility'') (the ''Acquisition''), including those of the Alberta Energy and Utilities Board (the ''AEUB'') and the British Columbia Utilities Commission (the ''BCUC''), and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition as itemized in the Acquisition Agreements (as defined below) (collectively, the ''Release Conditions''). If the Release Conditions are satisfied prior to 5:00 p.m. (Toronto time) on June 30, 2004, the Corporation will forthwith execute and deliver a notice of satisfaction and will issue and deliver to the Escrow Agent one Common Share for each Subscription Receipt then outstanding (subject to any applicable adjustment). The Common Shares will be available for delivery commencing on the second business day after the delivery of such notice. The holders of Subscription Receipts will receive, without payment of any additional consideration, one Common Share for each Subscription Receipt held plus an amount equal to the dividends declared on the Common Shares by the Corporation to holders of record on a date during the period from the Closing Date (as defined below) to the date of issuance of the Common Shares in respect of the Subscription Receipts. Forthwith upon the Release Conditions being satisfied and the required notice being delivered to the Escrow Agent, the Escrowed Funds, together with interest earned and income generated thereon, will be released to Fortis. In the event that the Release Conditions are not satisfied prior to 5:00 p.m. (Toronto time) on June 30, 2004 or, if either of the Acquisition Agreements is terminated prior to such time (in either case, the ''Termination Time''), holders of Subscription Receipts will, commencing on the second business day following the Termination Time, be entitled to receive from the Escrow Agent an amount equal to the full subscription

	price thereof plus their *pro rata* share of the interest earned or income generated on such amount. See ''Details of the Offering''.
Use of Proceeds:	The proceeds of this offering, (the ''Offering''), after deducting the fee payable to Scotia Capital Inc. (''Scotia Capital''), BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc. and Beacon Securities Limited (the ''Underwriters'') and expenses of the Offering, which are estimated to be $800,000, together with funds to be advanced under acquisition financing arranged by the Corporation, will be used to finance the aggregate $1,360 million consideration payable for the Acquisition including the repayment of certain indebtedness of the Alberta Utility and the B.C. Utility. The gross proceeds from the sale of the Subscription Receipts will be held in escrow pending the satisfaction of the Release Conditions, which is expected to occur in the first half of 2004. See ''Financing of the Acquisition'', ''Details of the Offering'' and ''Use of Proceeds''.
Subscription Receipts:	Each Subscription Receipt entitles the holder thereof to receive one Common Share, and a cash payment equal to the dividends declared on the Common Shares, upon satisfaction of the Release Conditions, without payment of additional consideration. If the Release Conditions are not met prior to the Termination Time, the Corporation will repay to holders of Subscription Receipts an amount equal to the full subscription price thereof plus their *pro rata* share of the interest earned or income generated on such amount. See ''Details of the Offering''.
Risk Factors:	An investment in the Subscription Receipts and the Common Shares issuable upon exchange thereof involves certain risks which should be carefully considered by prospective investors, including: regulation, the lack of an existing market for Subscription Receipts, results of operations and financing risks, management of expanding operations, the ability to realize benefits from the Acquisition, asset maintenance, damage from weather and other natural disasters, loss of service areas, obtaining and maintaining government permits, the financial position of Aquila, Inc. (''Aquila''), potential undisclosed liabilities associated with the Acquisition, litigation affecting the Corporation, ability to maintain satisfactory labour relations, exposure to interest rate changes, matters relating to insurance, availability of capital resources, environmental matters and the lack of consent by Arthur Andersen. See ''Risk Factors''.

The Acquisition

Overview

On September 15, 2003, Fortis entered into (i) a share purchase agreement with Aquila Networks Canada Ltd. (''ANCL'') for the purchase of all of the issued and outstanding shares, and the repayment of certain indebtedness, of the Alberta Utility (the ''Alberta Purchase Agreement''), and (ii) a share purchase agreement with Aquila Networks British Columbia Ltd. (''ANBC'') for the purchase of all of the issued and outstanding shares, and the repayment of certain indebtedness, of the B.C. Utility (the ''B.C. Purchase Agreement'') (ANCL and ANBC are hereinafter collectively referred to as the ''Vendors'', and the Alberta Purchase Agreement and the B.C. Purchase Agreement are hereinafter collectively referred to as the ''Acquisition Agreements'') for aggregate consideration of $1,360 million. The purchase price is subject to certain adjustments including with respect to working capital and changes to property, plant and equipment. The closing of the Acquisition is subject to receipt of required regulatory and other approvals, including those of the AEUB and the BCUC, and the satisfaction of closing conditions customary to an acquisition of this type. The closing of the Acquisition is expected to occur in the first half of 2004. See ''Acquisition Agreements''.

The Alberta Utility and the B.C. Utility together provide electricity to more than 525,000 customers in 160 communities in southern British Columbia and southern and central Alberta. The Alberta Utility and the B.C. Utility own and operate an aggregate of approximately 110,000 kilometres of electric transmission and distribution lines and the B.C. Utility owns 205 MW of hydroelectric generation capacity. As of December 31, 2002, the Alberta Utility and the B.C. Utility had an aggregate of $1,308 million in assets, an aggregate rate base of approximately $943 million and an aggregate of approximately 1,200 employees.

Based on financial information as at June 30, 2003, following the Acquisition Fortis' total assets will increase by approximately 75% to surpass $3.6 billion in total assets. Fortis' regulated asset base will increase to approximately $2.8 billion, of which approximately 85% will be located in Canada.

The Corporation intends to finance the purchase price for the Acquisition including the repayment of certain indebtedness of the Alberta Utility and the B.C. Utility from the net proceeds of the Offering and funds to be advanced to the Corporation, the Alberta Utility and the B.C. Utility under acquisition financing arranged by the Corporation for this purpose. See ''Financing of the Acquisition'' and ''Use of Proceeds''.

Under the Acquisition Agreements, either party thereto may elect to terminate the agreements if the Acquisition is not completed prior to 5:00 p.m. (Toronto time) June 30, 2004. It is a condition of closing that the acquisition of the Alberta Utility and the B.C. Utility occur contemporaneously.

The Alberta Utility

The Alberta Utility owns and operates a largely rural distribution system in a substantial portion of southern and central Alberta. It distributes electricity to more than 385,000 customers in Alberta, of which 311,000 are classified as residential. The Alberta Utility's distribution system includes approximately 100,000 kilometres of power lines that transmit electricity from transmission systems or generators owned by third parties to consumers. The Alberta Utility does not own any substation, transmission or generation assets. The retail business that formerly comprised part of the Alberta Utility's assets was disposed of in transactions completed on November 28, 2000 and January 1, 2001, for aggregate consideration of approximately $210 million. The Alberta Utility is not engaged in any material unregulated activities.

At December 31, 2002, the Alberta Utility had $847 million in assets and a rate base of approximately $527 million. Fortis expects the Alberta Utility's rate base to grow to approximately $800 million by 2008 as a result of customer growth and capital expenditures. For the year ended December 31, 2002, the Alberta Utility had electrical rate revenues of $248 million and net income of $28 million.

The Alberta Utility is regulated by the AEUB using a cost-of-service methodology. The regulated capital structure for the Alberta Utility is currently 60% debt and 40% equity. The Alberta Utility currently earns a regulated rate of return on its equity of 9.50%.

Fortis believes that the business operated by the Alberta Utility is attractive for the following reasons: (i) the Alberta Utility's operations are entirely regulated and complement Fortis' experience in regulated distribution; (ii) the cost-of-service regulatory framework in Alberta allows recovery of all approved costs as well as an appropriate return on equity; (iii) it is not subject to any electricity commodity risk; (iv) the Alberta Utility's distribution system is efficient and well maintained; (v) the Alberta Utility has an attractive service territory providing for well-diversified distribution revenues; and (vi) strong economic trends in Alberta are anticipated to result in low risk rate base growth provided by new customer connections and required capital expenditures.

The B.C. Utility

The B.C. Utility operates as a regulated integrated utility which generates, transmits and distributes electricity in the southern interior of British Columbia to approximately 140,000 customers, of which 50,000 customers are served through the wholesale sale of power by the B.C. Utility to municipal distributors. The B.C. Utility's integrated utility assets include four hydroelectric generating plants on the Kootenay River with an aggregate installed capacity of 205 MW, which supply approximately 50% of the B.C. Utility's customer electricity requirements, and approximately 10,000 kilometres of transmission and distribution lines. The balance of the B.C. Utility's electricity requirements are met through a portfolio of long and short term power purchase contracts approved by the BCUC, the cost of which are flowed through to customers. The B.C. Utility's unregulated activities are not material relative to its regulated operations, but provide an opportunity to enhance utilization of the B.C. Utility's utility operation and management resources under service contracts to third parties.

At December 31, 2002, the B.C. Utility had $461 million in assets and a rate base of approximately $416 million. Fortis expects the B.C. Utility's rate base to grow to approximately $780 million by 2008 as a result of a comprehensive capital expenditure program aimed at meeting customer growth, improving reliability and lowering operating costs. For the year ended December 31, 2002, the B.C. Utility had revenues of $154 million and net income of $12 million, excluding a $6 million after-tax non-recurring charge.

The B.C. Utility is regulated by the BCUC. The regulated capital structure for the B.C. Utility is approximately 60% debt and 40% equity. The regulated return on equity for 2003 is 9.82%. The B.C. Utility also has the benefit of a performance-based regulation mechanism that allows it to share up to 50% of various cost savings with the balance returned to customers.

Fortis believes that the business operated by the B.C. Utility is attractive for the following reasons: (i) the business of the B.C. Utility is virtually entirely regulated and complements Fortis' experience with integrated utilities; (ii) the B.C. Utility has an attractive service territory with revenue diversity from a mature customer base; (iii) the B.C. Utility offers significant opportunity for low-risk, regulated rate base growth due to its capital expenditure program focused on reliability; (iv) the B.C. Utility has 205 MW of regulated hydroelectric generation capacity; and (v) the B.C. Utility has virtually no commodity exposure.

Acquisition Rationale

Fortis believes that the principal benefits of the Acquisition are as follows:

(a) the Acquisition is a strategic investment opportunity for Fortis that is expected to enhance long-term shareholder value and significantly increase the regulated asset base of Fortis, which will create a broader foundation for Fortis to continue to grow its earnings;

(b) the Alberta Utility and the B.C. Utility are economically attractive franchises with well-diversified, mature, principally residential, customer bases, operating in separate and predictable regulatory jurisdictions and, similar to other Fortis utilities, under principally cost-of-service regulation in which prudent costs are recoverable and an appropriate return on capital is provided;

(c) the Acquisition is expected to improve the risk profile of Fortis by providing it with a more geographically and economically diverse portfolio of assets. The increased diversification to, and growth in, Fortis' regulated assets, earnings and cash flows are anticipated to mitigate the effect of any single adverse event and support Fortis' strategy of pursuing acquisition opportunities both in Canada and outside of Canada and, in appropriate circumstances, capitalizing on opportunities where prospects of enhancing existing non-utility operations exist;

(d) following the Acquisition, Fortis will be a diversified, Canadian electric utility holding company with regulated operations in five Canadian provinces with no one operating company accounting for more than 25% of the earnings, assets or cash flow of Fortis;

(e) the Acquisition affords Fortis management an opportunity to deploy its regulatory, operating and financial management expertise to additional Canadian regulated utilities;

(f) the equity financing Fortis is raising through the Offering will increase the market capitalization of Fortis, which will enhance market liquidity and access to the capital markets;

(g) based on the analysis made by Fortis' management, the Acquisition will provide key financial benefits to Fortis. The purchase price is expected to be equal to 1.3 times the anticipated rate base at the time of closing. The purchase price premium as it relates to rate base will reduce as the rate base grows over the next five years. The Acquisition is expected to be slightly dilutive to earnings in the early years following the closing of the Acquisition; and

(h) Fortis expects the rate base of the Alberta Utility and the B.C. Utility to grow by an average of 6% and 11% per year, respectively, over the next five years. In addition, Fortis believes that certain operational savings can be achieved, which it expects will be shared with customers.

See ''Risk Factors — Realization of Acquisition Benefits'' and ''Special Note Regarding Forward-Looking Statements''.

Utility Management Approach of Fortis

Fortis' approach to utility management is based on creating value for customers that ultimately translates into long-term value for shareholders. Fortis maintains proximity to its customers in each jurisdiction where it carries on a utility business by structuring its operating utilities as separate operating companies with dedicated, focused local management teams that have the benefit of access to Fortis' utility management experience and expertise. This allows local managers to build relationships with customers and regulators. Fortis recognizes that regulation is a key aspect of its core business and has developed a disciplined, cost-conscious asset investment and operating philosophy to achieve these objectives.

Fortis believes the businesses of the Alberta Utility and the B.C. Utility are complementary to its proven core competencies in managing regulated distribution and hydroelectric investments. In addition, Fortis believes the Acquisition provides a broader platform on which to deploy its regulatory operating and management expertise.

Selected *Pro Forma* Consolidated Financial Information of the Corporation

The following table presents selected *pro forma* consolidated financial information of the Corporation for the year ended December 31, 2002 and the six months ended June 30, 2003, after giving effect to the Acquisition and the Offering, based upon the assumptions and adjustments, as set out in the notes to the unaudited *pro forma* consolidated financial statements contained herein. The *pro forma* consolidated financial information set out below has been derived from these unaudited *pro forma* consolidated financial statements and should be read in conjunction with such statements and the notes thereto. The unaudited *pro forma* consolidated financial statements included in the Prospectus are not necessarily indicative of results of operations that would have occurred in the year ended December 31, 2002 or the six months ended June 30, 2003 had the Acquisition been effective January 1, 2002.

	Six months ended June 30, 2003	Year ended December 31, 2002
	(in millions of dollars, except per share amounts)	
Operating revenues	593	1,138
Operating expenses	447	849
Net operating income	146	289
Earnings (loss) applicable to common shares	(25)	81
Total assets	3,687	— (1)
Earnings (loss) per common share (basic)	(1.05)	3.58

(1) A *pro forma* balance sheet is required to be prepared as at June 30, 2003 but not as at December 31, 2002. Accordingly, a *pro forma* total asset amount has not been calculated as at December 31, 2002.

FORTIS

Fortis was incorporated as 81800 Canada Ltd. under the *Canada Business Corporations Act* on June 28, 1977. The Corporation was continued under the *Corporations Act* (Newfoundland) on August 28, 1987 and on October 12, 1987 the Corporation amended its articles to change its name to ''Fortis Inc.'' The address of the head office and principal place of business of the Corporation is The Fortis Building, Suite 1201, 139 Water Street, St. John's, Newfoundland and Labrador A1B 3T2.

Fortis is principally a diversified electric utility holding company with six electric distribution and generation utility subsidiaries. It holds all of the common shares of Newfoundland Power Inc. (''Newfoundland Power'') and, through Fortis Properties Corporation (''Fortis Properties''), holds all of the common shares of Maritime Electric Company, Limited (''Maritime Electric''), which are the principal distributors of electricity in the provinces of Newfoundland and Labrador and Prince Edward Island, respectively. Through Maritime Electric, the Corporation owns FortisUS Energy Corporation (''FortisUS Energy''), which operates four hydroelectric generating stations in the State of New York. As well, through its wholly-owned subsidiary FortisOntario Inc. (''FortisOntario'') and its subsidiaries Canadian Niagara Power Inc. (''CNPI''), Cornwall Street Railway, Light and Power Company Limited (''Cornwall Electric'') and Eastern Ontario Power Inc. (''Eastern Ontario Power''), Fortis distributes electricity to customers in Fort Erie, Port Colborne, Cornwall and Gananoque, Ontario.

Fortis also owns 100% of Central Newfoundland Energy Inc., (''Central Newfoundland Energy''), a non-regulated subsidiary, whose principal activity is its 51% involvement in the Exploits River Hydro Partnership project. The project is a partnership with Abitibi-Consolidated Inc. (''Abitibi-Consolidated'') to develop additional capacity at Abitibi-Consolidated's hydroelectric plant at Grand Falls-Windsor and to redevelop Abitibi-Consolidated's hydroelectric plant at Bishop's Falls, both in Newfoundland and Labrador.

Through a wholly-owned subsidiary, Fortis also holds a 95% interest in Belize Electric Company Limited (''BECOL''). BECOL owns and operates the Mollejon hydroelectric facility, located on the Macal River in Belize, Central America. Also in Belize, Fortis, through wholly-owned subsidiaries, holds 67% of the outstanding shares of Belize Electricity Limited (''Belize Electricity''), the prime transmitter and distributor of electricity in Belize. Fortis also owns, through a wholly-owned subsidiary, a 38.2% interest in Caribbean Utilities Company, Ltd. (''Caribbean Utilities''), the sole provider of electricity to the island of Grand Cayman, Cayman Islands.

Through its non-utility wholly-owned subsidiary, Fortis Properties, Fortis has investments in commercial real estate and hotel operations in Atlantic Canada.

Fortis believes that its primary focus of growth will be the acquisition of electric utility assets. Fortis will continue to pursue acquisition opportunities both in Canada and outside of Canada. Fortis will also carry out strategic assessments of its non-utility operations to identify and, in appropriate circumstances, capitalize on opportunities where prospects of enhancing existing non-utility operations exist.

Newfoundland Power

Newfoundland Power operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador. Newfoundland Power serves approximately 220,000 customers, constituting 85% of all electricity customers in the province. Approximately 90% of the energy required by Newfoundland Power is purchased from Newfoundland and Labrador Hydro Corporation, a provincial Crown corporation. Newfoundland Power generates the balance of its energy requirements. It has an installed generating capacity of approximately 150 MW comprised of hydroelectric, diesel and gas turbine generation with the bulk, 95 MW, coming from hydroelectric facilities.

FortisOntario

FortisOntario is an integrated electric utility. Through FortisOntario's wholly-owned subsidiaries, CNPI, Cornwall Electric and Eastern Ontario Power, electricity is distributed to approximately 52,000 Ontario customers in Fort Erie, Port Colborne, Gananoque, Cornwall, South Glengarry, South Stormont and the Ontario portion of the Mohawk Territory of Akwesasne. FortisOntario owns and operates the 75 MW Rankine Electric Generating Station on the Niagara River in Niagara Falls, Ontario. FortisOntario's licence to divert water from the Niagara River will expire on April 30, 2009. The Lieutenant Governor in Council of Ontario may, in its sole discretion, extend this licence for a further 20-year term. FortisOntario also owns and operates a 5 MW gas-fired cogeneration plant that provides district heating to commercial customers in Cornwall, Ontario. FortisOntario's wholly-owned subsidiary, Granite Power

Generation Corporation, generates electricity from five hydroelectric generating stations with a combined capacity of 6 MW.

On August 14, 2003, CNPI and Cornwall Electric, both regulated subsidiaries of FortisOntario, issued by way of private placement $52 million aggregate principal amount of 7.092% senior unsecured notes maturing in 2018. The proceeds of the private placement were used primarily to refinance existing short-term indebtedness.

Maritime Electric

Maritime Electric operates an integrated electric utility, which directly supplies approximately 67,500 customers constituting over 90% of the electricity consumers on Prince Edward Island. Maritime Electric owns and operates generating plants on Prince Edward Island with a total capacity of 100 MW but purchases most of the energy it distributes to its customers from New Brunswick Power, a provincial Crown corporation, and Emera Inc. Maritime Electric's system is connected to the mainland power grid via two submarine cables between Prince Edward Island and New Brunswick.

Maritime Electric's wholly-owned subsidiary, FortisUS Energy, operates four hydroelectric generating stations in upper New York State having a combined generating capacity of 23 MW.

Belize Electricity

Belize Electricity is the primary transmitter and distributor of electric power in Belize. Serving almost 62,300 customers, Belize Electricity satisfies Belize's aggregate peak demand of 57 MW from multiple sources, which include power purchases from BECOL, the Comissión Federal de Electricidad, which is the Mexican state-owned power company, and from its own oil-fired generating stations. Belize Electricity currently operates 49.3 MW of oil generation.

Belize Electricity has signed a new power purchase agreement with Hydro Maya Limited. The agreement is to purchase output from a 2.6 MW run of the river hydro plant in the Punta Gorda District (Southern Belize) which is expected to become operational in January 2006. It is expected that annual energy output will average 11.5 GWhs.

BECOL

BECOL owns and operates the Mollejon hydroelectric facility located on the Macal River in Belize, Central America. The facility is a 25 MW generating plant capable of delivering average annual energy of 80 GWh and is the only commercial hydroelectric facility in Belize. BECOL sells its entire output to Belize Electricity. BECOL operates under various agreements with the Government of Belize and Belize Electricity, including a 50-year power purchase agreement with Belize Electricity and a franchise agreement with the Government of Belize. The franchise agreement grants BECOL the right to use the water in the Macal River upstream of the Mollejon plant for hydroelectric generation and the Government of Belize has agreed not to grant any rights or take any action that would impede the amount or quality of water flow on the upper Macal River.

In November 2001, BECOL received environmental clearance for the Chalillo project, an upstream storage and generation facility that is expected to increase BECOL's annual energy production from an average of 80 GWh to 160 GWh. In December 2002, BECOL received additional support for the Chalillo project when, in response to a challenge initiated by the Belize Alliance for Conservation Non-Government Organizations who oppose the construction of a hydroelectric dam, the Supreme Court of Belize ruled that the environmental approvals for the project were in order. In March 2003, the Court of Appeal upheld this ruling of the Supreme Court of Belize and the Public Utilities Commission of Belize approved construction of the Chalillo project. In its decision, the Court of Appeal also granted leave to appeal its decision to the Judicial Committee of the Privy Council (the ''Privy Council''). In April 2003, an application for injunctive relief was filed with the Privy Council to prevent construction of the Chalillo project. On August 13, 2003, the Privy Council ruled that it would not grant Belize Alliance for Conservation Non-Government Organizations its request for an injunction against the project but will hear the full appeal application on December 3 and 4, 2003.

Caribbean Utilities

Caribbean Utilities is the sole provider of electricity to the Island of Grand Cayman, Cayman Islands pursuant to an exclusive 25-year licence renewable in 2011 with the Government of the Cayman Islands (the ''Cayman Government''). Caribbean Utilities generates, transmits and distributes electricity to more than 20,000 customers with an installed capacity of 123 MW.

Caribbean Utilities submitted a proposal to the Cayman Government in July 2002, to extend its current licence and replace the 15% return on rate base mechanism for adjusting consumer rates with a price cap mechanism. Under the proposal, electricity rates would be tied to and move with published inflation indices. Additionally, Caribbean Utilities would continue to recover fuel cost, regulatory cost, and government levies. Caribbean Utilities anticipates that under the proposed regulatory framework, it would continue to have the potential to achieve returns that are consistent with investor expectations.

Caribbean Utilities filed its 2003 annual return with the Cayman Government as required under the terms of its licence. The annual return indicated that, pursuant to the terms of its licence, Caribbean Utilities was entitled to a 3% rate increase, which it implemented effective August 1, 2003. The Cayman Government responded in August 2003 by requesting a voluntary rollback of the rate increase effective immediately and indicating that it would consider seeking injunctive relief against Caribbean Utilities if it did not comply.

After further discussions to resolve this issue proved unsuccessful, Caribbean Utilities suspended all licence extension negotiations with the Cayman Government until the legal aspects of this matter are fully resolved. Caribbean Utilities will defend its position vigorously should the Cayman Government choose to seek injunctive relief. Caribbean Utilities will continue to operate under the terms of its current licence, which expires in 2011. The final terms of any new agreement will be subject to the approval of the board of directors of Caribbean Utilities.

Central Newfoundland Energy

In June 2001, the Corporation, through a non-regulated subsidiary, Central Newfoundland Energy, entered into an agreement with Abitibi-Consolidated to develop additional capacity at Abitibi-Consolidated's hydroelectric plant at Grand Falls-Windsor and to redevelop Abitibi-Consolidated's hydroelectric plant at Bishop's Falls, Newfoundland and Labrador. The project is expected to cost $68 million, of which $63.4 million has been incurred as of June 30, 2003. The project has been financed principally with non-recourse debt and will increase annual energy production from the two hydroelectric plants by approximately 140 GWh. The installation of six new generating units and the refurbishment of the remaining three units at the Bishop's Falls generating station was completed in April 2003 and the Bishop's Falls hydroelectric plant was officially inaugurated on July 28, 2003. It is expected that construction at the Grand Falls-Windsor generating station will be complete and the plant will be operational by the end of 2003.

Fortis Properties

Fortis Properties is a leading owner and operator of commercial real estate and hotels in Atlantic Canada. Fortis Properties is the only non-utility subsidiary of Fortis and the primary vehicle for diversification and growth outside the electric utility business, with interests in office buildings, shopping centres, hotels and the provision of property management services. At August 30, 2003, Fortis Properties held a commercial real estate portfolio of 2.7 million square feet and eight hotels with more than 1,500 rooms. Its assets and income are distributed between Newfoundland and Labrador, Nova Scotia and New Brunswick and are diversified between commercial real estate and hotel operations, providing stability and opportunity for growth.

On September 17, 2003 Fortis Properties completed a $35 million ten-year refinancing of the Brunswick Square complex in Saint John, New Brunswick. On September 17, 2003, Fortis Properties announced that it had entered into an agreement with FelCor Lodging Trust to acquire four full-service hotels in Ontario for $43.2 million. The hotels are located in Sarnia, Kitchener-Waterloo, Cambridge and Peterborough. The four hotels have a total of 630 rooms ranging in size from 143 to 184 rooms.

THE ACQUISITION

Overview

On September 15, 2003, Fortis entered into the Acquisition Agreements for aggregate consideration of $1,360 million. The purchase price is subject to certain adjustments including with respect to working capital and changes to property, plant and equipment. The closing of the Acquisition is subject to receipt of required regulatory and other approvals, including those of the Alberta Energy and Utilities Board (the ''AEUB'') and the British Columbia Utilities Commission (the ''BCUC''), and the satisfaction of closing conditions customary to an acquisition of this type. See ''Acquisition Agreements''. Under the Acquisition Agreements, either party thereto may elect to terminate the agreements if the Acquisition is not completed prior to 5:00 p.m. (Toronto time) June 30, 2004. It is a condition of closing that the acquisition of the Alberta Utility and the B.C. Utility occur contemporaneously.

Aquila, a U.S. based utility holding company with approximately US$9 billion in assets at December 31, 2002 and 2002 revenues of over US$2 billion, experienced a loss from operations of US$2.1 billion in 2002. Fortis understands that Aquila has been working to restore its financial stability and refocus its business on owning and operating natural gas and electric utilities in the United States. Fortis understands that in the second quarter of 2003, Aquila, through its financial advisor Credit Suisse First Boston LLC, began a process to solicit interested buyers for its Canadian electric utility businesses in Alberta and British Columbia. Aquila received indicative bids in July from interested parties. Certain of these interested parties were selected to submit further bids in August. Following a period of negotiation, Fortis and the Vendors entered into the Acquisition Agreements on September 15, 2003.

The Corporation intends to finance the purchase price for the Acquisition including the repayment of certain indebtedness of the Alberta Utility and the B.C. Utility from the net proceeds of the Offering and funds to be advanced to the Corporation, the Alberta Utility and the B.C. Utility under acquisition financing arranged by the Corporation for this purpose. See ''Financing the Acquisition'' and ''Use of Proceeds''.

The Alberta Utility and the B.C. Utility together provide electricity to more than 525,000 customers in 160 communities in southern British Columbia and southern and central Alberta. The Alberta Utility and the B.C. Utility own and operate an aggregate of approximately 110,000 kilometres of electric transmission and distribution lines and the B.C. Utility owns 205 MW of hydroelectric generation capacity. As of December 31, 2002, the Alberta Utility and the B.C. Utility had an aggregate of $1,308 million in assets, an aggregate rate base of approximately $943 million and approximately 1,200 employees.

Based on financial information as at June 30, 2003, following the Acquisition, Fortis' total assets will increase by approximately 75% to surpass $3.6 billion in total assets. Fortis' regulated asset base will increase to approximately $2.8 billion, of which approximately 85% will be located in Canada.

Acquisition Rationale

Fortis believes that the principal benefits of the Acquisition are as follows:

(a) the Acquisition is a strategic investment opportunity for Fortis that is expected to enhance long-term shareholder value and significantly increase the regulated asset base of Fortis, which will create a broader foundation for Fortis to continue to grow its earnings;

(b) the Alberta Utility and the B.C. Utility are economically attractive franchises with well-diversified, mature, principally residential, customer bases, operating in separate and predictable regulatory jurisdictions and, similar to other Fortis utilities, under principally cost-of-service regulation in which prudent costs are recoverable and an appropriate return on capital is provided;

(c) the Acquisition is expected to improve the risk profile of Fortis by providing it with a more geographically and economically diverse portfolio of assets. The increased diversification to, and growth in, Fortis' regulated assets, earnings and cash flows are anticipated to mitigate the effect of any single adverse event and support Fortis' strategy of pursuing acquisition opportunities both in Canada and outside of Canada and, in appropriate circumstances, capitalizing on opportunities where prospects of enhancing existing non-utility operations exist;

(d) following the Acquisition, Fortis will be a diversified, Canadian electric utility holding company with regulated operations in five Canadian provinces with no one operating company accounting for more than 25% of the earnings, assets or cash flow of Fortis;

(e) the Acquisition affords Fortis management an opportunity to deploy its regulatory, operating and financial management expertise to additional Canadian regulated utilities;

(f) the equity financing Fortis is raising through the Offering will increase the market capitalization of Fortis, which will enhance market liquidity and broader access to the capital markets;

(g) based on the analysis made by Fortis' management, the Acquisition will provide key financial benefits to Fortis. The purchase price is expected to be equal to 1.3 times the anticipated rate base at the time of closing. The purchase price premium as it relates to rate base will reduce as the rate base grows over the next five years. The Acquisition is expected to be slightly dilutive to earnings in the early years following the closing of the Acquisition; and

(h) Fortis expects the rate base of the Alberta Utility and the B.C. Utility to grow by an average of 6% and 11% per year, respectively, over the next five years. In addition, Fortis believes that certain operational savings can be achieved, which it expects will be shared with customers.

Utility Management Approach of Fortis

Fortis' approach to utility management is based on creating value for customers that ultimately translates into long-term value for shareholders. Fortis maintains proximity to its customers in each jurisdiction where it carries on a utility business by structuring its operating utilities as separate operating companies with dedicated, focused local management teams that have the benefit of access to Fortis' utility management experience and expertise. This allows local managers to build relationships with customers and regulators. Fortis recognizes that regulation is an important aspect of its core business and has developed a disciplined, cost-conscious asset investment and operating philosophy to achieve these objectives.

Fortis believes the businesses of the Alberta Utility and the B.C. Utility are complementary to its proven core competencies in managing regulated distribution and hydroelectric investments. In addition, Fortis believes the Acquisition provides a broader platform on which to deploy its regulatory and management expertise.

ELECTRIC UTILITIES MARKET OVERVIEW

Alberta

History of Regulation of Distribution and Retail Services

As a result of the 1998 amendments to the *Electric Utilities Act* (Alberta) (the ''EUA'') and the enactment and amendment of various related regulations, customers of regulated electric distribution access systems were given a choice, commencing January 1, 2001, to select their electric energy retailer. The electric distribution access systems continued to be regulated to provide distribution service for the commodity sale of electricity to end-users. Independent retailers became eligible to sell electricity to end-users within an electric distribution system service area, with the utility providing the distribution service. A provision was made for the continuation of retail services to end-users who chose to stay with the distribution system utility during a five-year transition period.

The EUA provides the framework for the new structure in Alberta's electric utility industry and introduces competition into the electric utility business. As of January 1, 2001, new generation was completely deregulated and retail competition was introduced. In August 2002, the Government of Alberta announced further changes to utility legislation in order to improve the environment for retail competition in the province of Alberta. The Government of Alberta introduced a new EUA during 2003, which is designed to bring customer choice for both natural gas and electricity into closer alignment as well as to move towards consistent regulatory treatment of investor-owned and municipally-owned utilities.

Generation

Under the EUA, generation assets constructed after December 31, 1995 are not considered part of utility operations and rates are not regulated by the AEUB. All owners of new and existing generating units must sell their surplus electric energy through the Alberta Power Pool. Since 1998, 3,286 MW of new capacity has been added in Alberta and an additional 5,458 MW of new capacity is expected to be completed by 2006.

Transmission

The electricity delivery system in Alberta consists of a large network of interconnected transmission and distribution lines and related facilities. Alberta has transmission interconnection with British Columbia and Saskatchewan. Alberta has virtually no direct interconnection with the United States. Power is typically imported or exported through British Columbia via the transmission lines of British Columbia Hydro and Power Authority (''B.C. Hydro'').

Under the EUA, separate wholesale tariffs for transmission must be approved by the AEUB. The transmission tariffs allow any owner of a generating unit to have access to the transmission system in Alberta and thus facilitate the sale of its power. The same transmission tariff is charged to each distribution utility or customer directly connected to the transmission system regardless of location. The equalization of transmission costs is achieved by having each owner of transmission facilities charge its costs to the independent system operator which aggregates these costs and charges a common transmission rate to all who use the transmission system.

Distribution

Distribution of electricity throughout Alberta continues to be regulated by the AEUB. Under the EUA, separate rates for distribution access must be approved by the AEUB. Costs of distribution access are not equalized. The distribution utility provides the distribution access services for all customers under AEUB approved tariffs, which provide for the recovery of the cost-of-service, including a fair return on rate base.

The distribution system in Alberta is comprised of networks of the Alberta Utility, ATCO Ltd., multiple local distributors, including companies owned by the cities of Calgary and Edmonton, smaller municipalities and rural electrification associations.

Retail

As of January 1, 2001, all customers were granted a choice as to the supplier of their electric energy. Industrial and large commercial customers were required to select a retailer effective January 1, 2001. Other customers may continue to purchase electricity from their current distribution utility under a regulated rate option (a ''Regulated Rate Option''). The Regulated Rate Option is to be available for five years (2001 — 2005) for residential and farm customers and for three years (2001 — 2003) for small commercial and small industrial customers.

The Regulated Rate Option Tariff is also set by the AEUB and permits the distribution system utility to recover the cost-of-service of buying electric energy for and reselling it to customers within the distribution utility's service area.

On December 11, 2002, the AEUB approved an application requesting the implementation on January 1, 2003 of a monthly method of calculating electricity prices for regulated rate option customers. The new methodology is intended to provide greater price transparency for customers and to prevent large collection shortfalls or surpluses that would require subsequent adjustment by the AEUB.

British Columbia

The electric market in British Columbia is generally characterized by the traditional integrated utility model, where electric utilities generate, transmit and distribute electricity throughout their respective service territories. The BCUC regulates electric utilities in British Columbia and is responsible for setting and enforcing reliability and quality of service standards and for setting rates.

The B.C. Utility and B.C. Hydro, a Crown corporation, are the two largest vertically integrated utilities in British Columbia. B.C. Hydro serves the majority of electricity customers in British Columbia except in the B.C. Utility's service area in the West Kootenay region and parts of the Okanagan region in the interior of British Columbia. B.C. Hydro owns over 80% of the provincial generating capacity (11,115 MW). The remaining capacity is owned by the B.C. Utility, Columbia Power Corporation (''CPC''), industrial plants, and various independent power producers. CPC is a Crown corporation whose primary mandate is to undertake power project investments as the agent of the province on a joint venture basis with the Columbia Basin Trust.

The British Columbia grid is connected to Alberta and to Washington State allowing power to be sold and purchased outside the province. Current transfer capacity is 3,150 MW from British Columbia to the United States, 2,000 MW from the United States to British Columbia, 1,000 MW from Alberta to British Columbia, and 1,200 MW from British Columbia to Alberta.

On September 24, 1997, B.C. Hydro opened its transmission system to third parties as part of the requirement to obtain a Federal Energy Regulatory Commission license. The wholesale market in British Columbia was opened to competition in 1999, when a portion of the wholesale electric customers was allowed to choose an alternative electricity supplier. In November 2002 the government issued its new energy policy, ''Energy For Our Future: A Plan for B.C.''. The four cornerstones of the policy (the ''Proposals'') are low electricity rates and public ownership of B.C. Hydro, secure reliable supply, more private sector opportunities, and environmental responsibility and no nuclear power sources. The Proposals recommended that B.C. Hydro be divided into three entities responsible for generation, transmission and distribution.

Under the Proposals B.C. Hydro would manage its existing heritage assets and private producers would be expected to provide new power generation. Under the Proposals, B.C. Hydro would be expected to restructure such that its transmission activities are independent of its generation and distribution facilities. To date, an independent transmission company, the B.C. Transmission Company has been established to plan, operate and manage the B.C. Hydro system with continuing public ownership of transmission assets and provide non-discriminatory access to B.C. Hydro transmission system at rates determined by the BCUC.

THE ACQUIRED BUSINESSES

The description of the Alberta Utility and the B.C. Utility contained in the Prospectus is based on information provided by the Vendors in connection with the Acquisition Agreements. Fortis, after making its purchase investigations, believes it to be accurate in all material respects.

Aquila Networks Canada (Alberta) Ltd.

Overview and History

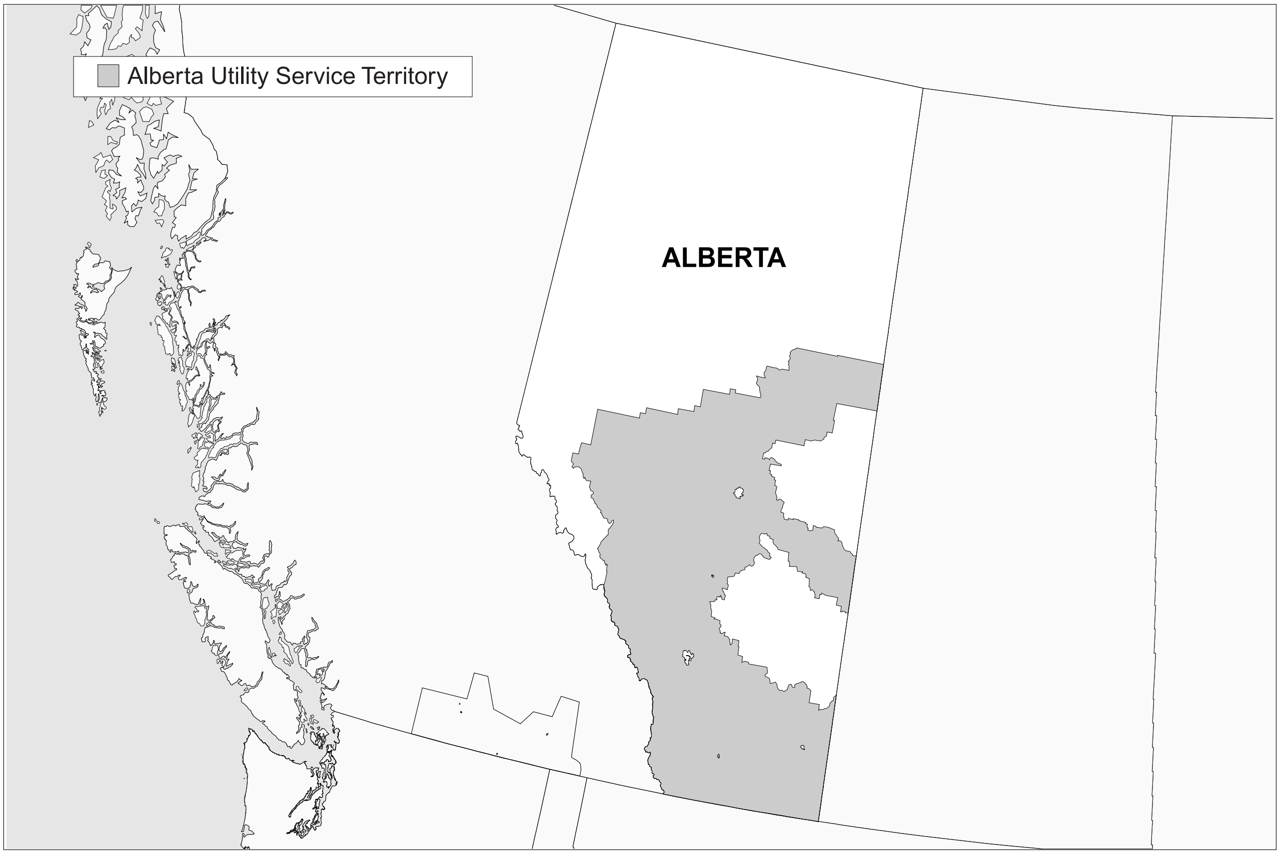
On August 31, 2000, Aquila acquired the electricity retail and distribution businesses in Alberta of TransAlta Utilities Corporation (''TransAlta''). On November 28, 2000, the Alberta Utility sold to EPCOR Energy Services (Alberta) Inc. (''EPCOR'') its intangible retail assets and certain related property, plant and equipment, for consideration of $110 million. On January 1, 2001, EPCOR also acquired the entire right, title and interest in the Alberta Utility's customer accounts receivable for additional cash consideration of approximately $100 million, before purchase price adjustments. No gain or loss was recorded on either the sale of the retail assets or the customer accounts receivable.

The Alberta Utility distributes electricity to more than 385,000 customers in Alberta. The Alberta Utility's service territory is mainly rural and covers approximately 169,000 square kilometres. At December 31, 2002, the Alberta Utility had $847 million in assets and a rate base of $527 million. Fortis expects the Alberta Utility's rate base to grow to approximately $800 million by 2008 as a result of customer growth and capital expenditures. For the year ended December 31, 2002, the Alberta Utility had electrical rate revenues of $248 million and net income of $28 million.

Principal Benefits of Acquisition of the Alberta Utility

Fortis believes that the business operated by the Alberta Utility is attractive for the following reasons: (i) the Alberta Utility's operations are entirely regulated and complement Fortis' experience in regulated distribution; (ii) the cost-of-service regulatory framework in Alberta allows recovery of all approved costs as well as an appropriate return on equity; (iii) it is not subject to any electricity commodity risk; (iv) the Alberta Utility's distribution system is efficient and well maintained; (v) the Alberta Utility has an attractive service territory providing for well-diversified distribution revenues; and (vi) strong economic trends in Alberta are expected to result in low risk rate base growth provided by new customer connections and required capital expenditures.

The Alberta Utility Service Territory



Asset and Business Summary

The Alberta Utility is an electricity distribution utility whose physical asset base is entirely regulated. As an electricity distribution utility, the Alberta Utility's distribution system receives power from either the transmission system (which it does not own) or from small third party power producers connected to the Alberta Utility's distribution system and then distributes the power at 25kV and lower voltages to end-use customers in its territory. It therefore has no exposure to fuel or power purchase prices. In 2002, the Alberta Utility distributed approximately 23,000 GWh to its customers, which represented approximately 47% of total electricity consumption in Alberta in that year.

The Alberta Utility's distribution system (the ''Alberta Electricity Distribution Assets'') comprises approximately 100,000 kilometres of overhead and underground conductors, approximately 150,000 service transformers and approximately 850,000 support structures. The Alberta Utility does not own any substation, transmission or generation assets. The overall quality of the Alberta Utility assets is consistent with a modern, utility standard. The Alberta Utility has entered into joint use agreements with telephone companies, municipal electricity and cable television companies under which the parties share the use and maintenance costs of the support structures they own and jointly use. The Alberta Utility is not engaged in any material unregulated activities.

System Growth

The Alberta Utility's forecasted capital expenditures relate primarily to sustaining capital expenditures related to routine maintenance of the distribution system and expansionary capital expenditures related to the connection of new customers to its distribution system, which will increase the Alberta Utility's rate base. Fortis expects the Alberta Utility will have approximately $111 million of capital expenditures, net of customer contributions in 2004, and will be funded from internally generated funds. Over the next five years to 2008, Fortis expects capital expenditures will contribute to rate base growth averaging approximately 6% annually.

Regulation and Current Distribution Rates

The Alberta Utility is regulated by the AEUB under cost-of-service methodology, which allows the Alberta Utility to recover all prudently incurred operating expenses, depreciation, income tax and interest on debt in addition to a return on equity. Current rates were approved in July 2003 and became effective August 1, 2003. The Alberta Utility was provided a regulated rate of return on its equity of 9.50% on a capital structure that has a 40% deemed equity component. The actual capital structure of the Alberta Utility is consistent with the deemed structure.

An annual revenue requirement of $205 million was approved by the AEUB for 2003. Approved operating costs of $107 million were $14 million less than requested in the Alberta Utility's application. Capital expenditures of approximately $111 million were also approved. The most significant change in the revenue requirement was a reduction in the depreciation rate of its distribution system assets from about 5.2% to 3.8% which is more in line with industry averages. This change resulted in a reduction in annual depreciation expense of approximately $25 million requiring a $37 million (13.5%) reduction in rates, and a $40 million rebate of 2002 rates. This change was applied retroactively and will remain in effect until a detailed depreciation study is completed by the Alberta Utility. During 2003, actual revenues will be reduced by approximately $58 million to reflect over-collections during the January 2002 to June 2003 period. Since the rebate in respect of 2002 revenue is being made in 2003, financial results in 2003 will compare unfavourably to 2002 and are expected to compare unfavourably to 2004. A lower depreciation rate means capital expenditures will exceed approved depreciation by a greater amount (all things being equal), resulting in growth in rate base.

Under current legislation, the Alberta Utility may maintain existing rates and generally does not need to reapply each year unless it wishes to establish new rates. The AEUB is holding a ''generic cost of capital'' hearing late in 2004 at which implementation of a standardized approach to determination of capital structure and rate of return for utilities in Alberta will be examined. Fortis believes that the AEUB wishes to begin setting rates of return by automatic formula beginning in 2005.

Service Territory Demographics — Customer and Load Mix

Alberta is an attractive service territory with strong economic growth measured by GDP growth at 9.2% annually for the five-year period ended 2002, ranking it second only to Newfoundland and Labrador among all provinces during that period.

The Alberta Utility serves approximately 385,000 residential, commercial, farm and industrial customers. Distribution revenues are well-diversified by customer type. Residential customers constitute the largest customer class numbering over 311,000 and accounted for approximately 33% of total revenues and 9% of total electricity load (''load'') in 2002. Industrial customers accounted for 29% of total revenues and 73% of total load in 2002. The oil and gas industry represents a significant majority of the Alberta Utility's industrial revenues. Commercial customers, including office buildings, department stores, malls, schools, hospitals, warehouses and other businesses accounted for 23% of total revenues and 12% of total load in 2002. Farm customers accounted for 12% of the total revenues and 5% of total load in 2002.

Since 1996, the residential segment has experienced the strongest customer growth at over 3% annually. Over the past decade the Alberta Utility's distribution system has experienced average annual customer growth of 2-3%. Fortis expects annual customer growth to remain consistent with historical levels.

Fortis believes that there are opportunities for significant improvement in customer service to a level equivalent to other Fortis utilities.

Supply of Power to Customers

The Alberta Utility serves 110 communities through individual franchise agreements that allow it to provide service in those communities. The typical franchise agreement in Alberta is for 10 years with an automatic renewal period of a further five years. Approximately 80% of the Alberta Utility's municipal franchises are based on a standard agreement that has an initial term that runs to 2011 with an automatic renewal to 2016. The remaining municipal franchises are governed by legislation that requires the municipality to give notice of termination in which case the Alberta Utility, as franchise holder, is required to be compensated. The City of Airdrie has given the Alberta Utility notice of its intention to terminate its franchise agreement. The Alberta Utility and the City of Airdrie are currently before the AEUB to establish the appropriate compensation of the Alberta Utility's assets in the City of Airdrie. The assets in the City of Airdrie have a rate base of approximately $9.0 million.

As an owner of an electric distribution system under the EUA, the Alberta Utility is required to make arrangements with or act as a default retailer to carry out the retailer functions for those customers that did not select a retailer by November 1, 2000 and may designate a supplier of last resort to provide electricity services to customers otherwise unable to obtain electricity services. In order to remain solely a distribution utility, in November 2000, the Alberta Utility appointed EPCOR to be a default retailer and supplier of last resort in its territory until the end of 2005. The Alberta Utility also has, either directly or indirectly, entered into approximately 80 service contracts with retailers.

Selected Historical Financial Information of the Alberta Utility

The following table presents selected financial and operating information for the Alberta Utility for the years ended December 31, 2002 and 2001 and the six months ended June 30, 2003 and 2002. The following information should be read in conjunction with the historical financial information of the Alberta Utility included in the Prospectus.

	Six Months ended June 30,		Year ended December 31,	
	2003	**2002**	**2002**	**2001**
	(in millions of dollars)			
Total revenues	70	129	269	253
Operating expenses	49 (1)	80	183	178
Net operating income	21 (1)	49	86	75
Net earnings (loss)	(66)	17	28	12
Total assets	783	— (2)	847	1,011

(1) Excludes goodwill impairment charge of $80 million.

(2) A balance sheet as at June 30, 2002 was not required for the purpose of the Prospectus.

Operational Environment

The operational environment in the Alberta Utility's service territory does not materially adversely impact utility operations with relatively limited snow, ice and extreme wind conditions.

Safety and Reliability

The Alberta Utility provides safe and reliable service throughout its service territory. The Alberta Utility's reliability statistics are in the top quartile when compared with other Canadian Electricity Association utilities.

Employees

The Alberta Utility has approximately 820 employees. ANCL has two collective agreements with the United Utility Workers Association, which expire on December 31, 2005.

EPCOR Litigation

In November 2000, EPCOR purchased from the Alberta Utility various assets necessary to operate the call centre and billing centre operations of the Alberta Utility. Additionally, EPCOR entered into agreements (the ''EPCOR Agreements'') pursuant to which it was appointed as the exclusive default retailer and supplier of last resort to customers within the Alberta Utility's service area and was granted the exclusive right to act as a retailer within the Alberta Utility's service area for customers purchasing electricity under the Alberta Utility's regulated rate tariff pursuant to a Regulated Rate Option Appointment Agreement.

Under the EPCOR Agreements, the Alberta Utility agreed to supply EPCOR, in a timely manner, with all information, including load settlement meter data in relation to customers in the Alberta Utility's service area, to permit EPCOR to exercise its rights and perform its duties under the EPCOR Agreements. On August 18, 2003, EPCOR filed a Statement of Claim in the Court of Queen's Bench of Alberta in the Judicial District of Edmonton against the Alberta Utility, ANCL and Aquila. EPCOR's claim is that the Alberta Utility, as owner of the distribution system, and ANCL, as the wire services provider, failed to provide EPCOR with timely and accurate information and data required by EPCOR to operate the retail business acquired from the Alberta Utility. EPCOR's claim alleges breaches of the EPCOR Agreements, breach of fiduciary duty and statutory duty by the Alberta Utility and ANCL, as well as negligence. EPCOR is seeking approximately $83 million in damages, interest, costs, an order compelling the Alberta Utility and ANCL to comply with the EPCOR Agreements and an order requiring the Alberta Utility to comply with its obligations. Aquila has been named as a defendant in the litigation as it guaranteed the performance by the Alberta Utility and ANCL of the EPCOR Agreements.

No statement of defence has yet been filed. The Alberta Utility and ANCL are currently considering their response to EPCOR's claim and have not to date made any definitive assessment of potential liability with respect thereto. In negotiating the purchase price and the terms of the Acquisition, Fortis took into consideration the potential liability of the defendants to EPCOR as a result of this claim. See ''Acquisition Agreements'' and ''Risk Factors''.

Aquila Networks Canada (British Columbia) Ltd.

Overview

The B.C. Utility operates as a regulated integrated utility and generates, transmits, distributes and sells electricity in the southern interior of British Columbia to approximately 140,000 customers, of which 50,000 customers are served through the wholesale sale of power to municipal distributors in Summerland, Penticton, Kelowna, Grand Forks, Nelson and Princeton. The B.C. Utility's operations cover a 50,000 square kilometre service territory.

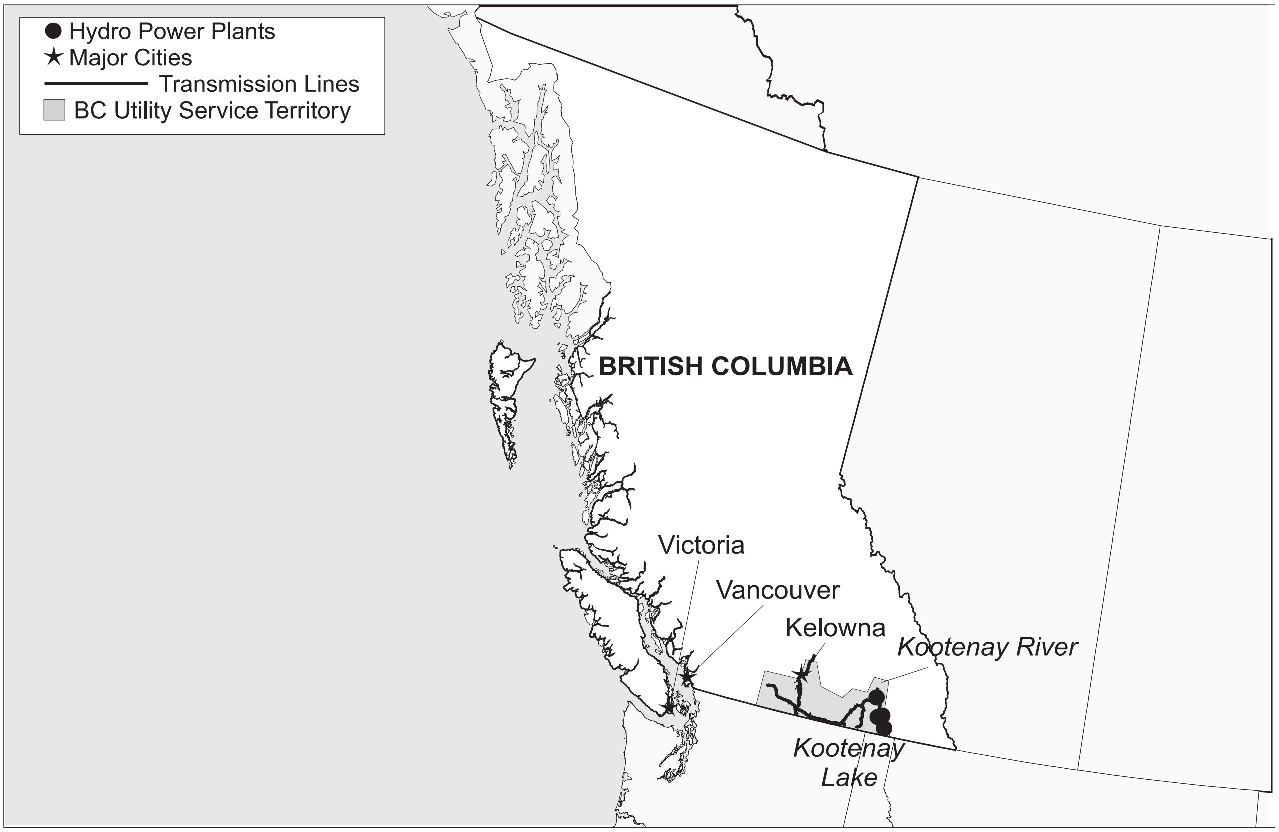
To supply customers with electricity, the B.C. Utility owns 205 MW of regulated hydroelectric generation capacity and meets the balance of its requirements through a portfolio of long-term and short-term power purchase contracts approved by the BCUC, the costs of which are flowed through to customers.

At December 31, 2002, the B.C. Utility had assets of $461 million and a rate base of approximately $416 million. Fortis expects the B.C. Utility's rate base to grow to approximately $780 million by 2008. Rate base growth is expected as a result of a comprehensive capital expenditure program aimed at meeting customer growth, improving reliability and lowering operating costs. Major components of the planned capital program, which have regulatory approval, include replacement of significant portions of the transmission system, upgrades to the hydroelectric generating plants and development of new substations. For the year ended December 31, 2002, the B.C. Utility had revenues of $154 million and net income of $12 million, excluding a $6 million after-tax non-recurring charge.

Principal Benefits of Acquisition of the B.C. Utility's Business

Fortis believes that the business operated by the B.C. Utility is attractive for the following reasons: (i) the business of the B.C. Utility is virtually entirely regulated and complements Fortis' experience with integrated utilities; (ii) the B.C. Utility has an attractive service territory with revenue diversity from a mature customer base; (iii) the B.C. Utility offers significant opportunity for low-risk, regulated rate base growth due to its capital expenditure program focused on reliability; (iv) the B.C. Utility has 205 MW of regulated hydroelectric generation capacity; and (v) the B.C. Utility has virtually no commodity exposure.

The B.C. Utility Service Territory



Asset and Business Summary

The B.C. Utility's integrated utility assets (the ''B.C. Electricity Generation, Transmission and Distribution Assets'') are comprised of an integrated network of generation, transmission and distribution assets. The B.C. Utility system interconnects with the B.C. Hydro system, and generation facilities owned by others providing additional supply and reliability benefits. The generation assets consist of four hydroelectric generating plants on the Kootenay River with an aggregate installed capacity of 205 MW. Its operations include approximately 10,000 kilometres of transmission and distribution power lines. The transmission assets include approximately 18 terminal transformers. The distribution system is comprised of 70 distribution substations, approximately 28,000 distribution service transformers and approximately 75,000 support structures. The B.C. Utility has entered into joint use agreements with telephone, municipal electricity and cable television companies under which the parties share the use and maintenance costs of the support structures they own and jointly use. Total electricity distributed to end use customers was approximately 2,800 GWh, with a peak system load of approximately 675 MW in 2002.

System Growth

In the late 1990s', in response to growing customer load and the desire to upgrade significant portions of the system to modern standards in order to ensure continued high reliability and reduced operating cost, the B.C. Utility established a comprehensive system renewal and redevelopment plan (the ''Master Plan''). The Master Plan has been filed with the BCUC and, subject to making individual CPCN (as defined below) applications, the B.C. Utility expects it will be allowed to recover capital expenditures incurred to implement those expenditures of the Master Plan approved by the BCUC through its rates. While sustaining capital expenditures related to routine maintenance are approximately $15 million annually, investment in the B.C. Utility's electrical system is expected to add over $300 million to its rate base by the end of 2008, an average annual increase in the B.C. Utility's rate base of approximately 11%. Capital expenditures are undertaken when approved by the BCUC pursuant to applications by the B.C. Utility for Certificates of Public Convenience and Necessity (''CPCN'') which ensures proposed expenditures have regulatory support and can be added to the rate base to earn a regulated return. When the projects identified in the Master Plan are complete, significant portions of the B.C. Utility system will consist of components consistent with a modern, utility standard.

Major projects identified in the Master Plan include:

(a) a new 230kV line and related station facilities in the Lower Columbia area to replace the current 63kV system;

(b) upgrades to the B.C. Utility's four Kootenay River hydroelectric plants;

(c) a new substation at Vaseux Lake (South Okanagan); and

(d) distribution system upgrades.

230kV System Development Project

A CPCN was granted in June 2000 for this project which involves the construction of a single new 230kV transmission line from South Slocan to Warfield, following a high-elevation backcountry corridor from South Slocan to Castlegar and the removal of multiple 63kV transmission lines. Switchyard improvements are also planned at the Brilliant Power Plant, Kootenay Canal Plant, and the B.C. Utility's four power plants on the Kootenay River and at the Warfield Station near Trail. This project represents a complete rebuild and reconfiguration of the transmission system in the Lower Columbia area. The new 230kV system will be interconnected with the facilities of other power producers and transmission operators in the region, thereby providing the B.C. Utility customers increased supply reliability and significantly reducing the likelihood of major outages. Additional expected benefits of the new system include reduced long-term operating and maintenance costs, improved safety, increased regional transmission capacity and reduced system losses.

When completed, the project is anticipated to be able to meet customer requirements in this region for the foreseeable future. The total cost of improvements is estimated to be approximately $115 million of which approximately $82 million is the B.C. Utility's estimated share. The first elements of this project were placed into service during 2003 and the project is expected to be complete during 2004. As part of this project, the B.C. Utility has recently entered into facility operations, management and interconnection agreements which will govern the operating and cost-sharing responsibilities between the B.C. Utility and the other utility system owners in the region.

Upgrades to the Kootenay River Hydroelectric Plants

A comprehensive hydroelectric generation upgrade program which will result in standardized electrical and mechanical components across all of the B.C. Utility's hydroelectric power plants has been initiated by the B.C. Utility. Total expected project costs from 2003 until completion in 2008 are approximately $136 million. Newly installed equipment is expected to enhance reliability and efficiency, while the use of standardized components is expected to reduce future maintenance and capital expenditures.

Vaseux Lake (South Okanagan) Substation

In the late 1980s' the B.C. Utility identified the need for additional electricity supply to the south Okanagan region to ensure customer demand post 2005 could be met at a reliability standard consistent with regulatory requirements. In order to increase supply to this region, the B.C. Utility is constructing a new 500kV substation. System improvements include terminal upgrades at Warfield, Grand Forks, Oliver and Penticton.

A CPCN for this project was granted by the BCUC in April 2003. Total project costs of approximately $69.9 million are expected and the facilities are scheduled to be in service by September 2005.

Distribution System Upgrades

Distribution system upgrades consist of improvements in the Trail area distribution system to renew obsolete components at or near the end of their useful life, to establish a standard voltage and to accommodate load growth that has caused load on the existing system to approach design capacity. Additional projects over the next five years include reliability upgrades in the Creston, Osoyoos and Slocan Valley regions.

Recent forest fires in British Columbia have caused an estimated $1 million in damage to the distribution system of the B.C. Utility. Fortis expects that these costs for the repair and upgrading of the system will be recovered in future rates.

Regulation and Current Rates

The B.C. Utility is regulated by the BCUC under a performance-based framework. The performance-based framework rewards cost-efficiency by allowing the utility shareholder to participate in achieved cost reductions, while providing for cost-of-service regulation during certain test years with subsequent rates determined by inflation less a defined productivity improvement factor. The reset of rates at defined intervals pursuant to a cost-of-service methodology allows the utility the benefit of recovery of prudently incurred operating costs and appropriate return on capital. The B.C. Utility operates as a regulated integrated utility — all of its assets constitute part of its rate base and prudently incurred power purchase costs are passed through to customers.

The B.C. Utility's 2003 rates have been set through a combination of the performance-based rate setting mechanism and a negotiated settlement of forecasts and extraordinary costs and deferrals. The existing performance-based rate mechanism has established a revenue requirement for 2003 based on tested forecast cost-of-service for 2000. The base revenue requirement is escalated each year based on customer and sales growth and inflation, less defined productivity improvement factors which for 2003 have been set at 1.0%. The revenue requirement is also adjusted for extraordinary capital and operating costs approved by the BCUC, forecast power purchases and changes in the cost of capital. The B.C. Utility currently earns a regulated rate of return on its equity of 9.82% on a capital structure that has a 40% deemed equity component. The actual capital structure of the B.C. Utility is consistent with the deemed structure.

The B.C. Utility is subject to an annual revenue requirement review and application of the performance-based mechanism which for 2003 has established a revenue requirement of $160 million representing a 4.3% rate increase over 2002. Under the performance-based framework, risk and reward is shared with customers. The B.C. Utility shares in up to 50% of achieved savings. In light of the substantial capital expenditures, to mitigate the impact of rate increases for customers, the B.C. Utility, with the approval of the BCUC, has established a rate stabilization reserve that has been used to limit rate increases to a maximum of 5% annually.

The year 2004 represents a rebasing year for the performance-based rate mechanism. In 2004, rates will be established on a cost-of-service basis using expected 2004 costs after a detailed review of each individual cost category. The performance-based rate mechanism and sharing mechanism used for establishing the B.C. Utility's revenue and rates for most years since 1992 has provided a return slightly higher than the regulated return set by the formula.

Service Territory Demographics — Customer Mix

The B.C. Utility serves a 50,000 square km service territory in the lower inland of British Columbia including the communities of Trail, Kelowna, Summerland, Penticton, Grand Forks, Castlegar, Rossland, Nelson and Princeton, serving approximately 140,000 customers, of which 50,000 customers are served through the wholesale sale of power to municipal distributors in Kelowna, Summerland, Penticton, Nelson and Grand Forks. The service territory is characterized as primarily rural residential. Key industries served by the B.C. Utility include the forestry and minerals industries.

The B.C. Utility has a diverse customer base comprised of residential, general service, wholesale (including municipal) and industrial customers. Low risk residential customers constitute the largest customer class and accounted for approximately 42% of total revenues and 36% of the total load in 2002. Additional residential customers are served under wholesale service, whereby the B.C. Utility sells power to municipally owned distribution systems. This accounted for approximately 22% of total revenues and 31% of the total load in 2002. General service customers, including office buildings, department stores, malls, schools, hospitals, warehouses and other businesses accounted for 22% of total revenues and 19% of total load in 2002. Industrial customers accounted for 11% of total revenues and 12% of the total load in 2002.

Fortis believes that there are opportunities for significant improvement in customer service to a level equivalent to other Fortis utilities.

Supply of Power to Customers

The B.C. Utility owns four hydroelectric generation facilities with an aggregate generation capacity of 205 MW located on the Kootenay River. The B.C. Utility meets approximately 50% of its power needs through generation or power entitlements related to these hydroelectric stations and acquires most of its remaining supply requirements through power purchase contracts with the balance met through spot market purchase contracts. Power purchase contracts are approved by the BCUC and prudently incurred costs are flowed through to customers. This diverse power supply mix provides the B.C. Utility with the flexibility to respond to changes in demand load with virtually no commodity exposure.

Owned Generation Facilities

UNIT	LOCATION	YEAR INSTALLED	UNIT CAPACITY (MW)	2002 NET GENERATION (MWH)
No. 1	Lower Bonnington	1924	41	289,851
No. 2	Upper Bonnington	1907	59	214,662
No. 3	South Slocan	1928	55	252,522
No. 4	Corra Linn	1932	50	201,848
Total			205	958,883

Power Purchase Agreements

Canal Plant Agreement

B.C. Hydro owns the 650 MW Kootenay Canal Generating Station (the ''Canal Plant''), which diverts water from the Kootenay River into a man-made canal that feeds the Canal Plant and runs parallel to the B.C. Utility's existing four plants on the Kootenay River, which are located between Castlegar and Nelson. In order to make efficient use of water flowing out of the Kootenay Lake and to avoid competing water demands between the existing generation facilities of the B.C. Utility and the Canal Plant, a coordination agreement (the ''Canal Plant Agreement'') was entered into in August 1972.

The Canal Plant Agreement provides for certain electrical generation arrangements among the owners of hydroelectric generation in the Kootenay Region of southeastern British Columbia. Under the Canal Plant Agreement, B.C. Hydro utilizes water otherwise licensed for use by the B.C. Utility in its power generation plants at Corra Linn, Upper Bonnington, Lower Bonnington and South Slocan. In return, B.C. Hydro provides the B.C. Utility with a fixed annual entitlement to energy and capacity. The annual entitlement is determined, in accordance with the agreement, as a percentage of the simulated average capability of the generation facilities. The B.C. Utility's power entitlements are approximately 205 MW of capacity and 1,540 GWh of energy. The B.C. Utility plants have to be maintained in a state of operational readiness in order to receive the full entitlements. In the event of a forced or maintenance outage, the entitlements are reduced by a proportionate amount. Allocation of the original generation entitlements considered the relative water use efficiencies of each of the generating units sharing the total water resources.

The Canal Plant Agreement is currently under negotiation for renewal prior to expiry in 2005.

Brilliant Power Purchase Agreement

Electricity generated by the Columbia Power Corporation and the Columbia Basin Trust (''CPC/CBT'') owned Brilliant Power Plant is transmitted to B.C. Hydro and in exchange, B.C. Hydro allocates a specified amount of power and capacity to the Brilliant Power Plant under the Canal Plant Agreement. Under a power purchase agreement (the ''BPPA''), the B.C. Utility has agreed to purchase from CPC/CBT on a long-term basis (a) the power and capacity allocated to the Brilliant Power Plant by B.C. Hydro and (b) after the expiration of the Canal Plant Agreement, the actual electrical output generated by the Brilliant Power Plant (collectively, the ''Brilliant Entitlement''). During the 60-year term of the BPPA, CPC/CBT has agreed to sell and make available to the B.C. Utility the entirety of the Brilliant Entitlement. During the second 30 years of the BPPA, a market-based adjustment will be made to the price. The BPPA provides the B.C. Utility with approximately 25% of its power requirements in its service territory.

Power Purchases from B.C. Hydro

The B.C. Utility is also party to a power purchase agreement with B.C. Hydro (the ''B.C. Hydro PPA'') that provides the B.C. Utility with additional electricity for purposes of supplying its load requirements, up to a maximum demand of 200 MW per hour, which constitutes about 23% of the B.C. Utility's electricity supply requirements. The current term of the B.C. Hydro PPA extends until 2013 and provides the B.C. Utility with electricity under fixed prices for that term.

Selected Historical Financial Information of the B.C. Utility

The following table presents selected financial and operating information for the B.C. Utility for the years ended December 31, 2002, 2001 and 2000 and the six months ended June 30, 2003 and 2002. The following information should be read in conjunction with the historical financial information of the B.C. Utility included in the Prospectus.

	Six Months ended June 30,		Year ended December 31,		
	2003	2002	2002	2001	2000
	(in millions of dollars)				
Total revenues	82	80	154	148	139
Operating expenses	63	58	134	109	105
Net operating income	19	22	20	39	34
Net earnings	9	10	6	17	12
Total assets	494	—(1)	462	408	367

(1) A balance sheet as at June 30, 2002 was not required for the purpose of the Prospectus.

Operational Environment

The operational environment in the B.C. Utility's service territory is more challenging than that of the Alberta Utility and includes heavy snowfall, high wind conditions and rural mountain terrain. See ''Risk Factors — Weather and Other Natural Disasters''.

Safety and Reliability

The B.C. Utility provides safe service throughout its service territory. In recent years, reliability has shown deterioration, however, the B.C. Utility has performed at or near the Canadian Electricity Association average for reliability.

Employees

The B.C. Utility has approximately 400 employees. The B.C. Utility has a collective agreement with the International Brotherhood of Electrical Workers, which expires on January 31, 2005. ANBC also has a collective agreement with the Office and Professional Workers International Union in British Columbia, which expires on January 31, 2006.

Unregulated Activities

The B.C. Utility's unregulated activities are not material relative to its regulated operations, but provide an opportunity to enhance utilization of the B.C. Utility's utility operation and management resources under service contracts to third parties.

The B.C. Utility provides operations, maintenance and management services relating to (i) the 400 MW Waneta hydroelectric generation facility owned by Teck-Cominco; (ii) the 150 MW Brilliant Hydroelectric Plant owned by CPC/CBT; (iii) the 150 MW Arrow Lakes Hydroelectric Plant owned by CPC/CBT (ANBC and CPC/CBT are currently negotiating the terms of a new, long-term management agreement for the Arrow Lakes facility); and (iv) the distribution system owned by the City of Kelowna.

In addition, the B.C. Utility owns the Walden Power Partnership, an independent power producer, which owns and operates a 16 MW run of the river, hydroelectric power plant near Lillooet, British Columbia. The Walden plant commenced operating in 1992 and sells 100% of its output to B.C. Hydro under a long-term contract.

Environmental Matters

Although primarily regulated at the provincial level, jurisdiction over the environment is shared by Canadian federal, provincial and local governments. As a result, the Alberta Utility and the B.C. Utility are subject to extensive federal, provincial and local regulation relating to the protection of the environment, including air emissions, water discharges and the generation, storage, transportation, disposal and release of various substances. In addition, both the provincial and federal governments have environmental assessment legislation, which is designed to foster better planning, and the identification and mitigation of potential environmental impacts of projects or undertakings prior to their commencement.

The primary federal legislation is the *Canadian Environmental Protection Act, 1999* (Canada), which regulates the use, import, export and storage of toxic substances, including PCBs and ozone-depleting substances, specifically to enable pollution prevention and the protection of the environment and human health in order to contribute to sustainable development. Another important piece of federal legislation is the *Fisheries Act* (Canada), which prohibits the deposit of deleterious substances into water which may be inhabited by fish and the destruction of fish habitat.

In December 2002, the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6% below the 1990 level by 2012. The protocol will only become legally binding when it is ratified by at least 55 countries, covering at least 55% of the emissions addressed by the protocol. If the protocol becomes legally binding, it is expected to affect the operation of all industries in Canada. Although the impact of the Kyoto agreement on the Alberta Utility and the B.C. Utility cannot be fully determined at this point, as a wire service provider and a hydroelectric generator (in the case of the B.C. Utility), Fortis expects that the overall impact should be minimal.

In Alberta, the principal provincial environmental legislation includes the *Environmental Protection and Enhancement Act* (Alberta) which establishes a comprehensive regime regulating releases and spills of contaminants, including PCBs and ozone-depleting substances, waste management and release reporting and cleanup criteria. Additionally, the *Water Act* (Alberta) supports and promotes the conservation and management of water, including the wise allocation and use of water.

In British Columbia, the primary provincial legislation includes the *Waste Management Act* (British Columbia), the *Environmental Assessment Act* (British Columbia), the *Water Act* (British Columbia) and the *Forest Practices Code of British Columbia Act* (British Columbia). The *Waste Management Act* (British Columbia) is an omnibus piece of legislation that regulates most aspects of the environment, including substance releases, waste storage and remediation standards. The *Forest Practices Code of British Columbia Act* (British Columbia), the *Forest Act* (British Columbia) and the *Forest and Range Practices Act* (British Columbia) are intended to ensure sustainable use of the forests through planning, stewardship and protection initiatives. The *Water Act* (British Columbia) is intended to coordinate the overall management of water through coordination of licences and permits to divert, use and store water.

Municipal regulation is primarily relevant in the context of discharges of industrial sewage and storm water run-off to the municipal sewer system.

As part of its purchase investigations, Fortis reviewed environmental records provided by the Vendors with respect to the policies, practices and assets of the Alberta Utility and the B.C. Utility. Fortis believes that the environmental compliance policies and practices of the Alberta Utility and the B.C. Utility are in accordance with industry standards.

ACQUISITION AGREEMENTS

Fortis has entered into a share purchase agreement dated as of September 15, 2003 with ANCL for the purchase of all of the issued and outstanding shares, and the repayment of certain indebtedness, of the Alberta Utility (the ''Alberta Purchase Agreement''), which company holds the Alberta Electricity Distribution Assets. Fortis has also entered into a share purchase agreement dated as of September 15, 2003 with ANBC for the purchase of all of the issued and outstanding shares, and the repayment of certain indebtedness, of the B.C. Utility (the ''B.C. Purchase Agreement''), which company holds all of the B.C. Electricity Generation, Transmission and Distribution Assets (the Alberta Purchase Agreement and the B.C. Purchase Agreement are collectively hereinafter referred to as the ''Acquisition Agreements''). Fortis may assign either agreement, and the right to purchase all of the issued and outstanding shares of the Alberta Utility or the B.C. Utility, as the case may be, to a wholly-owned subsidiary of Fortis prior to closing of the Acquisition. Fortis intends to assign each Acquisition Agreement to a separate indirect, wholly-owned subsidiary of Fortis. Each such subsidiary will be owned directly by a wholly-owned subsidiary of Fortis (''Acquisition Holdco'').

Purchase Price

The purchase price under the Alberta Purchase Agreement is $686 million (the ''Alberta Unadjusted Purchase Price'') and the purchase price under the B.C. Purchase Agreement is $674 million (the ''B.C. Unadjusted Purchase Price''). Under each Acquisition Agreement, the purchase price will be adjusted by (i) deducting indebtedness of the company being purchased to related companies and to certain third parties, (ii) adding (or deducting in the case of a deficit) the working capital of the applicable company as at the date of the closing of the Acquisition (which in the case of the Alberta Purchase Agreement will be reduced by an agreed amount of $19.2 million), (iii) adding or deducting, as applicable, an amount equal to the change in property, plant and equipment amounts reflected on balance sheets of the applicable company between December 31, 2003 and the date of the closing of the Acquisition, and (iv) in the case of the Alberta Purchase Agreement, adding the balance of a $21.7 million ''defect allowance'' to the extent it is not applied in respect of claims for breaches of representations and warranties. In certain circumstances where the value of the shares sold under an Acquisition Agreement is reduced as a result of an uncured or unwaived breach of a representation or warranty in such agreement by an amount that exceeds $6.74 million in the case of the B.C. Purchase Agreement, and $6.86 million, plus a ''defect allowance'' in an amount of $21.7 million, in the case of the Alberta Purchase Agreement, the purchase price will be adjusted downward by the amount the diminution in value exceeds that threshold. In the case where the diminution in value exceeds $68.6 million in respect of the Alberta Purchase Agreement or $67.4 million in respect of the B.C. Purchase Agreement, Fortis may terminate the applicable Acquisition Agreement.

Representations and Warranties

Under the Acquisition Agreements, the parties have made various representations and warranties that are customary for this type of transaction. The Vendors' representations and warranties relate to, among other things, absence of undisclosed litigation, absence of unpaid taxes, certain financial matters, compliance with laws and licences, title to the shares being purchased and the assets of the Alberta Utility and the B.C. Utility, as the case may be, the lack of sales or offices in the United States, the completeness of information disclosed to Fortis, the solvency of the Vendor and Aquila and certain environmental matters. The Vendors have also represented and warranted to Fortis that (generally, in the case of the B.C. Utility, and since the acquisition of the Alberta Utility by Aquila, in the case of the Alberta Utility) the business of such companies has been conducted in the ordinary course and in compliance with good industry practice, applicable law and all necessary authorizations. The Vendors have certain rights to cure breaches of representations and warranties prior to the closing of the Acquisition. The representations and warranties generally survive for 12 months following the closing of the Acquisition, except for (i) claims in respect of certain corporate organization and authorization matters (in respect of the Vendors, the Alberta Utility or the B.C. Utility, as applicable) and share capital and share title matters which survive indefinitely and (ii) claims in respect of taxes which survive for six months following the date on which notice of reassessment may be issued in respect of the year in which the closing of the Acquisition takes place. After the closing of the Acquisition, no action or proceeding may be brought or enforced by Fortis relating to the representation and warranty concerning completeness of information disclosed to Fortis in connection with the Acquisition.

Covenants

The parties to each of the Acquisition Agreements have made customary covenants relating to the closing of the Acquisition and related matters. In particular, each Vendor has agreed to conduct the business of the Alberta Utility and the B.C. Utility, as the case may be, in the ordinary course in accordance with good industry practice. The B.C. Utility has also agreed to enter into agreements, undertake projects and implement plans approved by the BCUC. In addition, the Acquisition Agreements impose limitations on the scope of business that may be conducted prior to closing of the Acquisition, including, among other things: (i) the length or value of contractual commitments and capital expenditures that the Alberta Utility and the B.C. Utility may undertake without the consent of Fortis (which may not be unreasonably withheld); (ii) the obligation of the Vendor to notify Fortis of the occurrence of certain events; and (iii) the right of Fortis to reasonable access to the Alberta Utility and the B.C. Utility and their management, employees and consultants. Each Vendor has further agreed that prior to the termination of the Acquisition Agreements, neither it nor any person on its behalf will discuss or negotiate any alternative transactions with third parties. Immediately following the closing of the Acquisition, Fortis has agreed to cause each of the Alberta Utility and the B.C. Utility to repay certain of their respective outstanding indebtedness.

Indemnities

Pursuant to the Acquisition Agreements, the Vendors, subject to certain limits, have agreed to indemnify and save harmless Fortis and its affiliates, and Fortis, subject to certain limits, has agreed to indemnify and save harmless the Vendors and their affiliates in respect of all claims sustained or incurred by the other resulting from (i) any misrepresentation or breach of warranty (other than the representation of the Vendor concerning completeness of information disclosed to Fortis) or (ii) failure to comply with, or the breach of, any covenants or agreements contained in the Acquisition Agreements. The indemnities provided by the Vendors or Fortis, as the case may be, are limited in certain respects in that claims may only be made under the indemnities in respect of a breach of a representation or warranty when the amount attributable thereto exceeds $100,000. The Vendor or Fortis, as the case may be, will only be obligated to indemnify the other party when the aggregate of all such losses exceeds $17.15 million in the case of the Alberta Purchase Agreement and $16.85 million in the case of the B.C. Purchase Agreement; however when such limitations are exceeded, the indemnity will apply in respect of all such claimed amounts. Under each Acquisition Agreement the maximum claim under the indemnity provisions by a party is $100 million. The above limitations do not apply to (i) any misrepresentation by a Vendor concerning certain corporate organization and authorization matters (in respect of both the Vendor and the Alberta Utility or the B.C. Utility, as applicable), share capital or share title matters or enforceability of the Acquisition Agreement, (ii) the obligation of Fortis to ensure the Alberta Utility or the B.C. Utility, as the case may be, repays certain outstanding indebtedness, or (iii) any misrepresentation by Fortis concerning certain corporate organization and authorization matters or enforceability of the Acquisition Agreement. The Vendors will also indemnify Fortis in respect of liabilities of the Alberta Utility and the B.C. Utility for taxes beyond amounts set out in tax filings or accounted for in closing adjustments. Acquisition Holdco will indemnify the Vendors and their affiliates in respect of certain claims made by EPCOR against the Alberta Utility, ANCL and Aquila. See ''The Acquired Businesses — Aquila Networks Canada (Alberta) Ltd. — EPCOR Litigation''.

Closing Conditions

Under each Acquisition Agreement, the obligations of a party to close are subject to certain conditions. These include: (i) the truth of the other party's representations and warranties, except where inaccuracies would not have a material adverse effect or as are permitted, subject to reduction of the purchase price; (ii) compliance by the other party with, and performance by the other party of, its agreements and covenants under the Acquisition Agreements, except where such failure would not have a material adverse effect; (iii) satisfaction by each party that all regulatory approvals have been obtained on terms that would not reasonably be expected to have a material adverse effect; (iv) satisfaction by each party that the terms and conditions of certain third party consents, releases and approvals that have been obtained or that the failure to obtain any of the said consents, releases and approvals would not reasonably be expected to have a material adverse effect; (v) no material adverse change in the business, results of operations, regulatory environment, assets and financial condition of the Alberta Utility or the B.C. Utility having occurred; (vi) Aquila shall have provided the Alberta Utility and the B.C. Utility with releases of any claims it has or may have against them; (vii) Aquila shall have delivered a guarantee to Fortis in respect of the performance of the Vendors under the Acquisition Agreements; (viii) the acquisition by Fortis, or by subsidiaries of Fortis, of a reviewable interest pursuant to section 54 of the *Utilities Commission Act* (British Columbia) shall have been approved by the BCUC; (ix) there must not be any judgment, decree, injunction, writ or order in effect that has had or would reasonably be expected to have a material adverse effect; (x) the receipt of customary legal opinions; and (xi) approval by the BCUC of the B.C. Utility Credit Facility (as described below).

The regulatory approvals that must be obtained prior to closing include:

(a) AEUB approval under section 102 and, if applicable, sections 101 and 109 of the *Public Utilities Board Act* (Alberta) of the transfer of the shares of the Alberta Utility to Fortis or a subsidiary of Fortis;

(b) AEUB approval under section 126(2) of the *Electric Utilities Act* (Alberta) and sections 36(1) and (2) of the *Public Utilities Board Act* (Alberta) of the transfer by the Vendor to the Alberta Utility, and assumption by the Alberta Utility, of the Vendor's obligations in respect of retail services agreements which provide certain large industrial electricity consumers access to the Alberta interconnected electric system;

(c) approval by the BCUC of the transfer of the shares of the B.C. Utility to Fortis or a subsidiary of Fortis; and

(d) if the parties have jointly determined that a filing or notification is required under the *Competition Act* (Canada) (the ''Competition Act''), one of the following has occurred: (i) an advance ruling certificate has been issued in respect of the Acquisition pursuant to section 102 of the Competition Act; (ii) the applicable waiting period under section 123 of the Competition Act has expired without the parties being advised that the Commissioner of Competition under the Competition Act (the ''Commissioner'') intends to issue an order under section 92 or 100 of the Competition Act in respect of the Acquisition; or (iii) the Commissioner has advised Fortis that he does not intend at the current time to apply for an order under section 92 of the Competition Act in respect of the Acquisition.

In addition, the Vendors' obligation to close the Acquisition is conditional on the Vendors obtaining (i) approval of the Kansas Corporation Commission under certain existing orders, of the transfer of the shares of the Alberta Utility and the B.C. Utility; and (ii) inclusion in the approvals listed above of AEUB and BCUC of a direction, order or decision that the proceeds of the transactions contemplated by the Acquisition Agreements are to be allocated to or otherwise accrue to the benefit of the shareholders of the Alberta Utility and the B.C. Utility.

Under the Acquisition Agreements, a Vendor is not required to close unless certain collective agreements and interconnection agreements have been assigned to Fortis or an affiliate of Fortis and the Vendor is released from its obligations thereunder. Under the Acquisition Agreements, Fortis will not be required to close unless consents have been obtained with respect to the assignment of numerous service, software, support and maintenance agreements and interconnection agreements from Aquila or its affiliates to the Alberta Utility or the B.C. Utility, as the case may be, and such assignment to Fortis or an affiliate of Fortis has occurred, except where the failure to obtain such consents or make such assignment would not have a material adverse effect on the Alberta Utility or the B.C. Utility, as applicable, or where the Vendor has made other arrangements satisfactory to Fortis for the supply of the service or software following closing.

The closing of the Acquisition must occur prior to 5:00 p.m. (Toronto time) June 30, 2004, unless extended by mutual agreement. The closing must not violate any applicable order, decree or judgment of any government authority, and the closings of both the purchase of the Alberta Utility and the B.C. Utility must occur concurrently. The parties expect the closing to occur in the first half of 2004.

Termination

An Acquisition Agreement may be terminated by a party thereto at any time prior to closing in certain circumstances including: (i) the mutual agreement of all of the parties to the agreement; (ii) if a government authority advises in writing that it will not be providing a necessary authorization; (iii) if an insolvency event occurs in respect of the other party; and (iv) if the closing of the transaction would violate an order, decree or judgment of a government authority that has not been stayed and the appeal periods in respect thereof have expired. An Acquisition Agreement may also be terminated by either party if the total of all defect amounts relating to breaches of representations and warranties exceeds $68.6 million under the Alberta Purchase Agreement and $67.4 million under the B.C. Purchase Agreement.

Related Agreements

Pursuant to a letter agreement dated September 15, 2003 between Fortis and Aquila, Fortis has agreed that Acquisition Holdco will offer replacement guarantees to the beneficiaries of certain existing guarantees (the ''Existing Guarantees'') that Aquila has provided in respect of obligations of the B.C. Utility under approximately $150 million of secured debentures and in respect of certain other obligations of the B.C. Utility. Fortis has also agreed to cause: (i) each of the Alberta Utility and the B.C. Utility to have certain minimum capitalization ratios at closing of the Acquisition; and (ii) Acquisition Holdco and the holders of the shares of the Alberta Utility and the B.C. Utility to agree to certain other financial obligations and restrictions, including in respect of the Alberta Utility, the B.C. Utility and the companies that hold their shares directly. In the event the beneficiaries of any Existing Guarantee do not release Aquila from its obligations thereunder prior to the closing of the Acquisition, Fortis will cause Acquisition Holdco to indemnify Aquila for any and all amounts paid by Aquila in accordance with the terms of Existing Guarantees.

FINANCING OF THE ACQUISITION

For purposes of financing the Acquisition, Fortis has obtained commitments from a Canadian chartered bank for a $730 million non-revolving credit facility in favour of Fortis (the ''Fortis Credit Facility''), a $393 million non-revolving credit facility in favour of the Alberta Utility (the ''Alberta Utility Credit Facility'') and a $277 million non-revolving credit facility in favour of the B.C. Utility (the ''B.C. Utility Credit Facility''). The funding of each of the Fortis Credit Facility, the Alberta Utility Credit Facility and the B.C. Utility Credit Facility (collectively, the ''Credit Facilities'') is subject to the execution of definitive documentation and fulfilment of other customary conditions. The Credit Facilities would be sufficient, if necessary, to fund the aggregate $1,360 million consideration payable for the Acquisition and the repayment of certain indebtedness of the Alberta Utility and the B.C. Utility. The B.C. Utility has outstanding $148.3 million principal amount of secured debentures of various series which may be prepaid prior to their maturity, subject to payment of a ''make-whole'' amount which is a premium over the outstanding principal amount. In the event that Fortis determines that such B.C. Utility secured debentures will not be repaid as part of the Acquisition, the B.C. Utility Credit Facility will be cancelled; however, in such event the Fortis Credit Facility will be increased by $130 million to an aggregate of $860 million. Fortis will use such increased amount to finance the refinancing of the remaining B.C. Utility debt.

The Fortis Credit Facility is an unsecured single borrowing credit facility to be used by Fortis, to the extent required, to finance the payment of the cash portion of the purchase price for the Acquisition. In the event that the purchase of the Alberta Utility and the B.C. Utility is effected through one or more wholly-owned subsidiaries of Fortis, the obligations of Fortis under the Fortis Credit Facility will be guaranteed by such subsidiary or subsidiaries. The Alberta Utility Credit Facility and the B.C. Utility Credit Facility are unsecured single borrowing credit facilities to be used by the Alberta Utility and the B.C. Utility, respectively, to refinance certain of their existing indebtedness. Any amount not drawn down under the Credit Facilities will be cancelled after the initial borrowing. The Credit Facilities will mature, in the case of the Fortis Credit Facility, on the second anniversary, and in the case of the Alberta Utility Credit Facility and the B.C. Utility Credit Facility, on the first anniversary of the earlier of: (i) the drawdown under the relevant facility, and (ii) the date that is six months after the credit agreement giving effect to the relevant credit facility is entered into, subject to the option of the Alberta Utility and the B.C. Utility to extend the terms to the third anniversary of such dates.

The Credit Facilities will contain certain prepayment options in favour of the borrowers and certain prepayment obligations upon the occurrence of certain events. In particular, the net proceeds of any equity or debt offering by Fortis and of any debt offering by the Alberta Utility or the B.C. Utility, and any post-closing purchase price adjustments paid to Fortis or its subsidiary purchasers in connection with the Acquisition, will be required to be used to prepay the relevant Credit Facilities. Any prepayment under the Credit Facilities may not be re-borrowed.

The Credit Facilities will contain customary representations and warranties and affirmative and negative covenants of the borrowers, including, in the case of Fortis, a consolidated debt to consolidated capitalization ratio which may not exceed 0.75:1 at any time during the first year of the Fortis Credit Facility and 0.70:1 at any time thereafter and, in the case of the Alberta Utility and the B.C. Utility, a consolidated debt to consolidated capitalization ratio which may not exceed 0.70:1. The Credit Facilities will contain customary events of default. In addition, any failure by Fortis, the Alberta Utility or the B.C. Utility to maintain an investment grade credit rating (being a rating of at least BBB– or its equivalent) will constitute an event of default under the relevant Credit Facility.

Customary fees are payable by the borrowers in respect of the Credit Facilities and amounts outstanding under the Credit Facilities will bear interest at market rates.

Fortis expects that the Alberta Utility Credit Facility and the B.C. Utility Credit Facility will be repaid from the proceeds of long-term debt to be borrowed by the Alberta Utility and the B.C. Utility following the closing of the Acquisition. The cost of this debt subject to regulatory approval will form part of the cost-of-service of each of the Alberta Utility and the B.C. Utility and will be recovered in rates. The net proceeds from the Offering will reduce the amount of the Fortis Credit Facility. Fortis expects that the Fortis Credit Facility will be repaid from the proceeds of one or more offerings of preferred shares and/or long-term debt. Fortis does not anticipate that it will issue additional Common Shares to repay the Fortis Credit Facility.

CAPITALIZATION

The following table sets out the consolidated capitalization of the Corporation as at June 30, 2003 and after giving effect to the Offering and completion of the Acquisition. The financial information set out below should be read in conjunction with the unaudited consolidated financial statements incorporated by reference into the Prospectus and the unaudited *pro forma* consolidated financial statements included in the Prospectus and, in each case, the notes thereto.

	Outstanding at June 30, 2003	*Pro forma* outstanding at June 30, 2003
	(in millions of dollars)	
Total debt	$1,080	$2,196
Shareholders' equity		
Securities offered hereby	—	341
Common shares	326	326
Preference shares	123	123
Equity Portion of Convertible Debentures	2	2
Retained Earnings and Contributed Surplus	272	272
Total capitalization	$1,803	$3,260

PRICE RANGE AND TRADING VOLUME OF THE COMMON SHARES

The outstanding common shares of Fortis (the ''Common Shares'') are traded on the Toronto Stock Exchange (the ''TSX'') under the trading symbol ''FTS''. The following table sets forth the reported high and low trading prices and trading volumes of the Common Shares as reported by the TSX from January 2002.

Period	High	Low	Volume
2002			
January	$47.25	$44.00	492,211
February	48.20	45.05	323,070
March	49.75	45.15	476,251
April	50.10	47.00	529,172
May	49.95	47.00	451,860
June	49.10	45.36	451,985
July	49.00	43.05	397,220
August	48.80	45.30	398,003
September	50.25	48.00	666,528
October	52.10	48.10	476,854
November	52.90	49.05	339,318
December	53.10	49.65	417,492
2003			
January	53.00	50.40	945,894
February	53.25	51.15	230,450
March	53.20	46.50	338,697
April	51.86	49.00	308,205
May	57.35	51.00	480,362
June	59.70	55.01	353,115
July	60.78	57.55	961,836
August	60.95	58.05	575,523
September 1 to 26	60.30	54.25	904,096

On September 26, 2003, the closing price of the Common Shares was $55.50.

SHARE CAPITAL OF FORTIS

The authorized share capital of the Corporation consists of an unlimited number of Common Shares and an unlimited number of First Preference Shares issuable in series and Second Preference Shares issuable in series, in each case without nominal or par value. As at September 26, 2003, 17,347,731 Common Shares and 5,000,000 First Preference Shares, Series C were issued and outstanding.

Holders of Common Shares are entitled to dividends on a *pro rata* basis if, as and when declared by the board of directors of Fortis. Subject to the rights of the holders of the First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive dividends in priority to or rateably with the holders of the Common Shares, the board of directors of Fortis may declare dividends on the Common Shares to the exclusion of any other class of shares of the Corporation. On the liquidation, dissolution or winding-up of Fortis, holders of Common Shares are entitled to participate rateably in any distribution of assets of Fortis, subject to the rights of holders of First Preference Shares and Second Preference Shares and any other class of shares of the Corporation entitled to receive the assets of the Corporation on such a distribution in priority to or rateably with the holders of the Common Shares. Holders of the Common Shares are entitled to receive notice of and to attend all annual and special meetings of the shareholders of Fortis, other than separate meetings of holders of any class or series of shares, and to one vote in respect of each Common Share held at such meetings.

DETAILS OF THE OFFERING

Subscription Receipts

The Subscription Receipts will be issued on the Closing Date (as defined below) pursuant to the Subscription Receipt Agreement. The Escrowed Funds will be delivered to and held by the Escrow Agent and invested in short-term interest bearing or discount debt obligations issued or guaranteed by the Government of Canada or a province, or one or more of the five largest Canadian chartered banks, provided that such obligation is rated at least R1 (middle) by Dominion Bond Rating Service Limited or an equivalent rating service, pending satisfaction of the Release Conditions.

If the Release Conditions are satisfied prior to 5:00 p.m. (Toronto time) on June 30, 2004, the Corporation will forthwith execute and deliver a notice of satisfaction and will issue and deliver to the Escrow Agent one Common Share for each Subscription Receipt then outstanding (subject to any applicable adjustment). The Common Shares will be available for delivery commencing on the second business day after the delivery of such notice. The holders of Subscription Receipts will receive, without payment of any additional consideration, one Common Share for each Subscription Receipt held plus an amount equal to the dividends declared on the Common Shares by the Corporation to holders of record on a date during the period from the Closing Date (as defined below) to the date of issuance of the Common Shares in respect of the Subscription Receipts. Forthwith upon the Release Conditions being satisfied and the required notice being delivered to the Escrow Agent, the Escrowed Funds, together with interest earned and income generated thereon, will be released to Fortis.

In the event that the Release Conditions are not satisfied or, if either of the Acquisition Agreements is terminated, prior to the Termination Time, holders of Subscription Receipts shall, commencing on the second business day following the Termination Time, be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* entitlement to interest earned or income generated on such amount. The Escrowed Funds will be applied toward payment of such amount.

In the event that, prior to the date of issue of a Common Share in respect of a Subscription Receipt, there is a subdivision, consolidation, reclassification or other change of the Common Shares or any reorganization, amalgamation, merger or sale of all or substantially all of the Corporation's assets, the Subscription Receipts will thereafter evidence the right of the holder to receive the securities, property or cash deliverable in exchange for or on the conversion of or in respect of the Common Shares to which the holder of a Common Share would have been entitled immediately after such event. Similarly, any distribution to all or substantially all of the holders of Common Shares of rights, options, warrants, evidences of indebtedness or assets will result in an adjustment in the number of Common Shares to be issued to holders of Subscription Receipts. Alternatively, such securities, evidences of indebtedness or assets may, at the option of the Corporation, be issued to the Escrow Agent and delivered to holders of Subscription Receipts on exercise thereof. In case the Corporation, after the Closing Date, takes any action affecting the Common Shares, other than the actions described above, which, in the reasonable opinion of the directors of the Corporation, would materially affect the rights of the holders of Subscription Receipts and/or the rights attached to the Subscription Receipts, then the number of Common Shares which are to be received pursuant to the Subscription

Receipts shall be adjusted in such manner, if any, and at such time as the directors of the Corporation may, in their discretion, reasonably determine to be equitable to the holders of Subscription Receipts in such circumstances. The adjustments provided for in this paragraph are cumulative and shall apply to successive subdivisions, consolidations, changes, distributions, issues or other events resulting in any adjustment.

Under the Subscription Receipt Agreement, purchasers of Subscription Receipts will have a contractual right of rescission following the issuance of Common Shares to such purchaser entitling the purchaser to receive the amount paid for the Subscription Receipts upon surrender of the Common Shares, if the Prospectus and any amendment contains a misrepresentation, provided such remedy for rescission is exercised within 180 days of the Closing Date (as defined below).

Subject to applicable law, the Corporation will be entitled to purchase the Subscription Receipts in the open market or by private agreement or otherwise.

Subscriptions for the Subscription Receipts will be received subject to rejection or allotment in whole or in part and the right is reserved to close the subscription books at any time without notice. It is expected that the closing of the Offering will take place on or about October 8, 2003 (the ''Closing Date''), or such other date as may be agreed upon by the Corporation and the Underwriters, but not later than November 7, 2003. The Subscription Receipts will be issued in ''book entry only'' form and must be purchased or transferred through a CDS Participant. The Corporation will cause a global certificate or certificates representing newly issued Subscription Receipts to be delivered to and registered in the name of CDS or its nominee. All rights of Subscription Receipt holders must be exercised through, and all payments or other money to which such holders are entitled will be made or delivered by, CDS or the CDS Participant through which the holders hold such Subscription Receipts. Each person who acquires Subscription Receipts will receive only a customer confirmation of purchase from the registered dealer from or through which the Subscription Receipts are acquired in accordance with the practices and procedures of that registered dealer. The practices of registered dealers may vary, but generally customer confirmations are issued promptly after execution of a customer order. CDS is responsible for establishing and maintaining book entry accounts for its CDS Participants having interests in the Subscription Receipts.

The Subscription Receipt Agreement provides for modifications and alternations to the Subscription Receipts issued thereunder by way of an extraordinary resolution. The term ''extraordinary resolution'' is defined in the Subscription Receipt Agreement to mean, in effect, a resolution proposed at a meeting of holders of Subscription Receipts duly convened for that purpose and held in accordance with the Subscription Receipt Agreement at which there are present in person or by proxy at least two holders of Subscription Receipts entitled to receive more than 25% of the aggregate number of Common Shares issuable upon the exchange of the Subscription Receipts which could be received pursuant to all the then outstanding Subscription Receipts and passed by the affirmative votes of holders of Subscription Receipts entitled to receive not less than 66⅔% of the aggregate number of such Common Shares which could be received pursuant to all the then outstanding Subscription Receipts represented at the meeting and voted on the poll upon such resolution.

The holders of Subscription Receipts are not shareholders of the Corporation. Holders of Subscription Receipts are entitled only to receive Common Shares on the exchange of their Subscription Receipts and an amount equal to the dividends declared on the Common Shares by the Corporation to holders of record on a date during the period from the Closing Date to the date of issuance of the Common Shares in respect of the Subscription Receipts, or to require the Corporation to purchase the Subscription Receipts at the issue price and to be paid a *pro rata* share of interest earned or income generated thereon as described above.

CHANGES IN SHARE AND LOAN CAPITAL STRUCTURE

The following changes in the share and loan capital structure of Fortis have occurred since December 31, 2002:

- In January 2003, Fortis borrowed US$45 million from a Canadian chartered bank, which was used to finance the purchase of additional shares of Fortis Energy (Bermuda) Ltd., to enable such subsidiary to increase its ownership interest in Caribbean Utilities to 38.2% from 22%. This loan was repaid in June 2003.
- During the period from January 1, 2003 up to and including September 26, 2003, Fortis issued an aggregate of 155,667 Common Shares pursuant to the Corporation's Dividend Reinvestment and Share Purchase Plan, Consumer Share Purchase Plan and Employee Share Purchase Plan and upon the exercise of options granted

pursuant to the Executive Stock Option Plan and Directors' Stock Option Plan for an aggregate consideration of $7,671,351.

- On May 20, 2003, Fortis issued by way of private placement, US$10 million aggregate principal amount of Subordinated Convertible Debentures bearing interest at an annual rate of 5.5% and maturing on May 20, 2013. The debentures are convertible into Common Shares at US$47.86 per share.
- In June 2003, Fortis completed a public offering of 5,000,000 5.45% cumulative redeemable convertible first preference shares, series C at a price of $25.00 per share for gross proceeds to the Corporation of $125 million.

USE OF PROCEEDS

The proceeds to the Corporation from the Offering, after deducting the fee payable to the Underwriters and estimated expenses of the Offering, are expected to be $335,396,800. The net proceeds of the Offering, together with funds to be advanced to the Corporation, the Alberta Utility and the B.C. Utility pursuant to the Credit Facilities, will be used to finance the aggregate $1,360 million consideration payable on the closing date for the Acquisition including the repayment of certain indebtedness of the Alberta Utility and the B.C. Utility. See ''The Acquisition — Financing of the Acquisition''. The gross proceeds from the sale of the Subscription Receipts will be held in escrow pending the satisfaction of the Release Conditions. See ''Details of the Offering''.

PLAN OF DISTRIBUTION

Pursuant to an underwriting agreement dated September 29, 2003 (the ''Underwriting Agreement'') between Fortis and the Underwriters, Fortis has agreed to issue and sell, and the Underwriters have agreed to purchase, as principals, on the Closing Date, 6,310,000 Subscription Receipts offered hereby at a price of $55.50 per Subscription Receipt, subject to compliance with all the necessary legal requirements and to the conditions contained in the Underwriting Agreement.

The Corporation has agreed to pay to the Underwriters a fee of $14,008,200 ($2.22 per Subscription Receipt) in consideration for its services in connection with the Offering. One-half of the Underwriters' fee in respect of the Offering is payable on the Closing Date and the other half of the Underwriters' fee is payable only if the Release Conditions have been satisfied prior to the Termination Time and the required notice has been delivered to the Escrow Agent.

Pursuant to policy statements of the relevant securities commissions, the Underwriters may not, throughout the period of distribution under the Prospectus, bid for or purchase Subscription Receipts or Common Shares into which they are exchangeable. The foregoing restriction is subject to certain exceptions, as long as the bid or purchase is not engaged in for the purpose of creating actual or apparent active trading in or raising the price of such securities. These exceptions include a bid or purchase permitted under the by-laws and rules of the TSX relating to market stabilization and passive market-making activities and a bid or purchase made to and on behalf of a customer where the order was not solicited during the period of distribution. Pursuant to the first-mentioned exception, in connection with the Offering, the Underwriters may over-allot or effect transactions which stabilize or maintain the market price of the Subscription Receipts or the Common Shares at levels other than those which may otherwise prevail on the open market. Such transactions, if commenced, may be discontinued at any time.

The Subscription Receipts and the Common Shares into which such Subscription Receipts may be exchanged have not been, and will not be, registered under the United States *Securities Act of 1933*, as amended (the ''1933 Act'') or any state securities laws and, subject to certain exceptions, may not be offered, or delivered, directly or indirectly, or sold in the United States except in certain transactions exempt from the registration requirements of the 1933 Act and in compliance with any applicable state securities laws. The Underwriters have agreed that they will not offer or sell the Subscription Receipts within the United States, its territories, its possessions and other areas subject to its jurisdiction or to, or for the account or benefit of, a ''U.S. person'' (as defined in Regulation S under the 1933 Act), except in accordance with the Underwriting Agreement pursuant to an exemption from the registration requirements of the 1933 Act provided by Rule 144A thereunder and in compliance with applicable state securities laws. In addition, until 40 days after the commencement of the Offering, an offer or sale of Subscription Receipts or Common Shares within the United States by any dealer (whether or not participating in the Offering) may violate the registration requirements of the 1933 Act if such offer is made otherwise than in reliance on Rule 144A.

The obligations of the Underwriters under the Underwriting Agreement may be terminated at their discretion upon the occurrence of certain stated events. The Underwriters are obligated to take up and pay for all of the Subscription Receipts if any are purchased under the Underwriting Agreement. Under the terms of the Underwriting Agreement, the Underwriters may be entitled to indemnification by the Corporation against certain liabilities, including liabilities for misrepresentation in the Prospectus.

Each of Scotia Capital, BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc. and TD Securities Inc. are affiliates of Canadian chartered banks that are part of a syndicate of banks that have agreed to extend credit facilities to the Corporation in connection with financing the Acquisition. Scotia Capital has agreed to act as the sole lead arranger and book runner in connection with this financing and is receiving a fee for its role as financial advisor to Fortis in connection with the Acquisition. Consequently, the Corporation may be considered a ''connected issuer'' of these Underwriters within the meaning of applicable securities legislation. None of these Underwriters will receive any direct benefit from the Offering other than the underwriting commission relating to the Offering. The decision to distribute the Subscription Receipts hereunder and the determination of the terms of the Offering were made through negotiation between the Corporation and the Underwriters. The chartered banks did not have any involvement in such decision or determination. See ''Use of Proceeds''.

The TSX has conditionally approved the listing of the Subscription Receipts. Listing is subject to Fortis fulfilling all of the requirements of the TSX on or before December 15, 2003.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Davies Ward Phillips & Vineberg LLP, counsel to the Corporation, and Stikeman Elliott LLP, counsel to the Underwriters, the following is a general summary of the principal Canadian federal income tax considerations generally applicable to a holder who acquires Subscription Receipts pursuant to the Offering who, within the meaning of the *Income Tax Act* (Canada) (the ''Tax Act''), and at all relevant times, is or is deemed to be resident in Canada, deals at arm's length with the Corporation and holds or will hold the Subscription Receipts and any Common Shares as capital property. Generally, the Subscription Receipts and the Common Shares will be considered to be capital property to a holder provided the holder does not hold the Subscription Receipts and the Common Shares in the course of carrying on a business and has not acquired them in a transaction or transactions considered to be an adventure in the nature of trade. Certain holders whose Common Shares might not otherwise qualify as capital property may, in certain circumstances, make the irrevocable election under subsection 39(4) of the Tax Act to have their Common Shares and every ''Canadian security'' (as defined in the Tax Act) owned by such holder in the taxation year of the election, and in all subsequent years, deemed to be capital property.

The Tax Act contains certain provisions (the ''Mark-to-Market Rules'') relating to securities held by certain financial institutions, registered securities dealers and corporations controlled by one or more of the foregoing. This summary does not take into account the Mark-to-Market Rules, and taxpayers that are ''financial institutions'' as defined for the purpose of the Mark-to-Market Rules should consult their own tax advisors.

This summary is based upon the provisions of the Tax Act and regulations thereunder (the ''Regulations'') in force as at the date hereof, all specific proposals to amend the Tax Act or Regulations that have been publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof and counsel's understanding of the current published administrative practices of the Canada Customs and Revenue Agency. This summary does not otherwise take into account or anticipate any changes in applicable law, whether by legislative, governmental or judicial decision or action, nor does it take into account provincial, territorial or foreign tax laws or considerations, which might differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be, nor should it be construed to be, legal or tax advice to any particular holder. This summary is not exhaustive of all possible income tax considerations under the Tax Act that may affect a holder. The income tax consequences of acquiring and disposing of Subscription Receipts and Common Shares will vary depending on a number of facts, including the legal status of the holder as an individual, corporation, trust or partnership. Accordingly, prospective holders of Subscription Receipts and Common Shares should consult their own tax advisors with respect to their

particular circumstances and the tax consequences to them of holding and disposing of Subscription Receipts and Common Shares.

Exchange of Subscription Receipts

No gain or loss will be realized by a holder on the exchange of Subscription Receipts for Common Shares.

The cost of a Common Share issued to a holder of a Subscription Receipt acquired pursuant to the Offering will be equal to the cost of the Subscription Receipt to the holder. The adjusted cost base to the holder of Common Shares so acquired will be determined by averaging the cost of such Common Shares with the adjusted cost base of all other Common Shares owned at that time by the holder as capital property.

Payment of Interest

As described above under ''Details of the Offering'', in the event that the Release Conditions are not satisfied or if either of the Acquisition Agreements is terminated prior to the Termination Time, holders of Subscription Receipts will be entitled to receive from the Escrow Agent an amount equal to the full subscription price thereof plus their *pro rata* entitlement to interest earned or income generated thereon. In that event, the amount of such interest or income received or receivable by a holder of Subscription Receipts (depending on the method regularly followed by the holder in computing income) must be included in the income of the holder.

Payment of Dividend Equivalent

As described above under ''Details of the Offering'', if Common Shares are issued in exchange for Subscription Receipts, and if dividends have been declared on the Common Shares of the Corporation to holders of record on a date during the period from the Closing Date to the date of such issuance of Common Shares, the Corporation will make a cash payment to the holders of Subscription Receipts in respect of each Subscription Receipt in an amount equal to the per share amount of such dividend. The equivalent to dividend amount, if any, paid to a holder of Subscription Receipts by the Corporation must be included in the income of the holder.

Other Dispositions of Subscription Receipts

A disposition or deemed disposition by a holder of a Subscription Receipt, other than on the exchange of a Subscription Receipt for a Common Share or a disposition of the Subscription Receipt to the Corporation in the event the Release Conditions are not satisfied or if either of the Acquisition Agreements is terminated prior to the Termination Time, will generally result in the holder realizing a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition exceed (or are less than) the aggregate of the holder's adjusted cost base thereof and any reasonable costs of disposition.

Dividends on Common Shares

Dividends received on Common Shares by a holder who is an individual will be included in the individual's income and will be subject to the gross-up and dividend tax credit rules normally applicable to taxable dividends received from taxable Canadian corporations. Taxable dividends received by an individual may give rise to alternative minimum tax under the Tax Act, depending on the individual's circumstances.

Dividends received on Common Shares by a holder that is a corporation will be included in income and normally will be deductible in computing such corporation's taxable income. However, the Tax Act will generally impose a 33 1/3% refundable Part IV tax on such dividends received by a corporation that was, at any time in the taxation year in which such dividends were received, a ''private corporation'' as defined in the Tax Act, or a corporation resident in Canada that is controlled by or for the benefit of an individual (other than a trust) or a related group of individuals (other than trusts), to the extent that such dividends are deductible in computing the corporation's taxable income.

Disposition of Common Shares

In general, a disposition or a deemed disposition of a Common Share will give rise to a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition of the Common Share, net of any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the holder of the Common Share immediately before the disposition.

Tax Treatment of Capital Gains and Losses

Generally, one-half of any capital gain realized by a holder in a taxation year will be included in computing the holder's income in such year. One-half of any capital loss realized by a holder in a taxation year normally may be deducted as an allowable capital loss by the holder against taxable capital gains realized by the holder in the year. Any allowable capital loss not deductible in the year it is realized generally may be carried back and deducted against taxable capital gains in any of the three preceding years or carried forward and deducted against taxable capital gains in any subsequent year (in accordance with the rules contained in the Tax Act). Capital gains realized by an individual will be relevant in computing possible liability for the alternative minimum tax.

The amount of any capital loss realized on the disposition or deemed disposition of a Common Share by a holder that is a corporation may be reduced by the amount of dividends received by the holder on the Common Share to the extent and in the circumstances prescribed by the Tax Act. Similar rules may apply where a holder that is a corporation is a member of a partnership or a beneficiary of a trust that owns Common Shares and where a trust is a member of a partnership that owns Common Shares or a partnership or trust is a beneficiary of a trust that owns Common Shares. Holders to whom these rules may be relevant should consult their own tax advisors.

Additional Refundable Tax

A holder that is a ''Canadian-controlled private corporation'' (as defined in the Tax Act) may be liable to pay an additional refundable tax of 6 2/3% on certain investment income, including amounts in respect of taxable capital gains and interest (but not dividends deductible in computing taxable income).

RISK FACTORS

An investment in the Subscription Receipts offered hereby and the Common Shares issuable upon the exchange thereof involves certain risks in addition to those described in the Management Discussion and Analysis of financial condition and results of operations contained in the Corporation's 2002 Annual Report incorporated by reference herein. Before investing, prospective purchasers of Subscription Receipts should carefully consider, in light of their own financial circumstances, the factors set out below, as well as the other information contained or incorporated by reference in the Prospectus.

Regulation

The regulated operations of the Alberta Utility and the B.C. Utility are subject to the normal uncertainties faced by regulated companies. These uncertainties include the approval by the AEUB and the BCUC, as applicable, of customer rates which permit a reasonable opportunity to recover on a timely basis the estimated costs of providing services, including a fair return on rate base. Upgrades of existing facilities and the addition of new facilities requires the approval of the regulators through the issuance of CPCNs. There is no assurance that capital projects perceived as required by the management of the Alberta Utility or the B.C. Utility will be approved or that conditions to such approval will not be imposed. Capital cost overruns relative to approvals granted in CPCNs might not be recoverable. The ability of the Alberta Utility and the B.C. Utility 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 process.

Rate applications that establish revenue requirements may be subject to negotiated settlement procedures in both Alberta and British Columbia. Failing a negotiated settlement, rate applications may be pursued through public hearing processes. Such rate applications will be required for the B.C. Utility in 2004 and the Alberta Utility in 2005. There can be no assurance that the rate orders issued will permit the Alberta Utility or the B.C. Utility to recover all costs actually incurred and to earn the expected rate of return. A failure to obtain acceptable rate orders may adversely affect the business carried on by each of the Alberta Utility and the B.C. Utility, the undertaking or timing of proposed expansion projects, the issue and sale of securities, ratings assigned by rating agencies, and other matters which may, in turn, negatively impact the Alberta Utility's or the B.C. Utility's results of operations or financial position, as well as those of the Corporation.

Alberta's regulatory framework has undergone significant changes since the deregulation of new generation and the introduction of retail competition on January 1, 2001. See ''Electric Utilities Market Overview''. Although Fortis considers the regulatory frameworks in each of Alberta and British Columbia to be fair and balanced, uncertainties do exist at the present time. The regulations and market rules which govern the competitive wholesale and retail electricity markets in Alberta are relatively new and there may be significant changes in these regulations and market rules that could adversely affect the ability of the Alberta Utility to recover its costs or to earn a reasonable return on its capital. Currently, British Columbia's regulatory framework is generally based on traditional cost-of-service methodologies for designing and setting rates.

Market for Securities

There is currently no market through which the Subscription Receipts may be sold. There can be no assurance that an active trading market will develop for the Subscription Receipts after the Offering, or if developed, that such a market will be sustained at the price level of the Offering.

Results of Operations and Financing Risks

Management of the Corporation believes, based on its expectations as to the Corporation's future performance (which reflects, among other things, the completion of the Acquisition), that the cash flow from its operations and funds available to it under its credit facilities will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management's expectations as to future performance will be realized. In addition, management's expectations as to the Corporation's future performance reflect the current state of its information about the Alberta Utility and the B.C. Utility and their operations and there can be no assurance that such information is correct and complete in all material respects.

Management of Expanding Operations

As a result of the Acquisition, significant demands will be placed on the Corporation's managerial, operational and financial personnel and systems. 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.

Realization of Acquisition Benefits

As described in ''The Acquisition — Acquisition Rationale'', the Corporation believes that the Acquisition will provide certain benefits to Fortis. However, there is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time-periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors including those disclosed in the Prospectus, many of which are beyond the control of the Corporation.

Asset Maintenance

The asset base for the Alberta Utility and the B.C. Utility each requires significant maintenance, improvement and expansion. Both utilities could experience service disruptions and increased costs if they are unable to maintain and replace their assets. Planned capital expenditures to maintain, improve or expand the asset base of each of the Alberta Utility and the B.C. Utility are substantial. The failure to carry out these capital expenditure programs could have a material adverse effect on each of the Alberta Utility and the B.C. Utility. These large capital projects will proceed under the authorization of a CPCN issued by the AEUB or the BCUC, as applicable. If actual costs exceed the costs forecast in obtaining the CPCN, it is uncertain as to whether any cost overruns will be approved and recovered.

Weather and Other Natural Disasters

The facilities of the Alberta Utility and the B.C. Utility are exposed to the effects of severe weather conditions and other acts of nature. Although their facilities have been constructed, operated and maintained to withstand severe weather, there is no assurance that they will successfully do so in all circumstances. In addition, many of these facilities are located in remote areas, which makes access for repair of damage due to weather conditions and other acts of nature difficult. The B.C. Utility operates facilities in remote and mountainous terrain with a risk of loss or damage from forest fires, floods, washouts, landslides, avalanches and similar acts of nature. The Alberta Utility and the B.C. Utility have limited insurance against storm damage and other natural disasters. In the event of a large uninsured loss caused by severe weather conditions or other natural disasters, application will be made to the AEUB or the BCUC, as applicable, for the recovery of these costs through higher rates to offset any loss. However, there can be no assurance that the AEUB or the BCUC would approve any such application. Losses resulting from repair costs and lost revenues could substantially exceed insurance coverage and increased rates. Furthermore, the Alberta Utility and the B.C. Utility could be subject to claims from their customers for damages caused by the failure to transmit or distribute electricity to them in accordance with their contractual obligations. Thus, any major damage to the Alberta Utility's or B.C. Utility's facilities could result in lost revenues, repair costs and customer claims that are substantial in amount, which amount could have a material adverse effect on the Alberta Utility or the B.C. Utility, as applicable.

Loss of Service Areas

The Alberta Utility serve a number of direct customers that reside within various municipalities throughout their service areas. From time to time municipal governments in Alberta give consideration to creating their own electric distribution utility by purchasing the Alberta Utility's assets that are located within their municipal boundaries. Under terms of the *Municipal Government Act* (Alberta), municipalities have the right to purchase the Alberta Utility's assets within municipal boundaries at replacement cost less depreciation.

The consequence to the Alberta Utility of this occurring would be a slow erosion of its rate base, which would adversely affect the return on capital it would earn in a regulated environment. Except for a current transaction involving the City of Airdrie, there have been no such transactions to date. The City of Airdrie recently gave the Alberta Utility notice of its intention to purchase the Alberta Utility's assets within its jurisdiction. The matter is currently before the AEUB for a determination to establish the value of the Alberta Utility's assets in the City of Airdrie. The assets within the service territory have a rate base of approximately $9.0 million. The Corporation believes that the risk of a significant number of such transactions occurring is relatively low as the formula providing for replacement cost less depreciation generally makes the price of acquiring the Alberta Utility's assets too high for a municipality.

The B.C. Utility provides service to customers on First Nations reserves in British Columbia and maintains generation, transmission and distribution facilities on lands that are subject to land claims by various First Nations bands. A treaty negotiation process with various First Nations bands is underway in British Columbia, but the basis upon which settlements might be reached in the B.C. Utility's service area is not clear. Furthermore, not all First Nations bands are participating in the process. To date, the policy of the British Columbia government has been to endeavour to structure settlements without prejudicing existing rights held by third parties, however, there can be no certainty that the settlement process will ultimately not adversely affect the B.C. Utility's business.

Government Permits

The acquisition, ownership and operation of electricity businesses and assets require numerous permits, approvals, and certificates from federal, provincial and local government agencies. Either or both of the Alberta Utility and the B.C. Utility 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 the Alberta Utility or the B.C. Utility fails to maintain or obtain any required approval or fails to comply with any applicable law or regulation, or condition of approval, the operation of its assets and its sales of electricity could be prevented or become subject to additional costs, any of which could have a material adverse effect on the Alberta Utility or the B.C. Utility.

The B.C. Utility's ability to generate electricity from its facilities on the Kootenay River, and to receive its energy entitlement under the Canal Plant Agreement, depends upon the maintenance of its water licences issued under the *Water Act* (British Columbia). In addition, water flows in the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States. Government authorities in Canada and the United States have the power under the treaty to regulate water flows to protect environmental values in a manner that might adversely affect the amount of water available for the generation of power.

Financial Position of Aquila

Aquila experienced a loss from operations of US$2.1 billion in 2002. A deterioration in Aquila's financial position could adversely affect the ability of Aquila and the Vendors to satisfy their guarantee and indemnity obligations pursuant to the Acquisition and could affect the ability of the Vendors to complete the Acquisition. See ''The Acquisition — Acquisition Agreements''.

Potential Undisclosed Liabilities Associated with the Acquisition

In connection with the Acquisition, there may be liabilities that the Corporation failed to discover or was unable to quantify in its due diligence which it conducted prior to the execution of the Acquisition Agreements and the Corporation may not be indemnified for some or all of these liabilities. The discovery of any material liabilities could have a material adverse effect on the Corporation's business, financial condition or future prospects.

EPCOR Litigation

The EPCOR litigation arises from issues related to the EPCOR Agreements. It is premature to make any definitive assessment of potential liability with respect to EPCOR's claim described under ''The Acquired Business — Aquila Networks Canada (Alberta) Ltd. — EPCOR Litigation''. However, if the EPCOR claim were to be successful, it could materially and adversely affect the business and operations of the Alberta Utility.

Labour Relations

Approximately 72% and 75% of the employees of the Alberta Utility and the B.C. Utility, respectively, are members of labour unions which have entered into collective bargaining agreements with ANCL and ANBC, respectively. The provisions of such collective bargaining agreements affect the flexibility and efficiency of the business carried on by each of the Alberta Utility and the B.C. Utility. Each of the Alberta Utility and the B.C. Utility considers its relationships with its labour unions 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, for the Alberta Utility or the B.C. Utility that are not provided for in approved orders, that could have an adverse effect on the results of operations, cash flow and net income of the Alberta Utility or the B.C. Utility, as applicable.

Interest Rates

The Alberta Utility and the B.C. Utility are exposed to the interest rate risks associated with floating rate debt. However, following the Acquisition, Fortis expects that the Alberta Utility and the B.C. Utility will replace these facilities with long-term fixed debt financing, the expenses of which will, subject to regulatory approval, be recovered in rates.

Allowed returns on equity for regulated utilities such as the Alberta Utility and the B.C. Utility are also exposed to changes in the general level of interest rates. As interest rates decrease, so does the allowed rate of return on equity.

Underinsured and Uninsured Losses

The Corporation, the Alberta Utility and the B.C. Utility maintain at all times insurance coverage in respect of potential liabilities and the accidental loss of value of certain of their assets from risks, in amounts, with such insurers, as is considered appropriate, taking into account all relevant factors including the practices of owners of similar assets and operations. It is anticipated that such insurance coverage will be maintained. However, not all risks are covered by insurance, and no assurance can be given that insurance will be consistently available or will be consistently available on economically feasible terms or that the amounts of insurance will be sufficient to cover losses or claims that may occur involving the assets or operations of the Corporation, the Alberta Utility or the B.C. Utility.

Capital Resources

Each of the Alberta Utility's and the B.C. Utility's financial position could be adversely affected if it fails 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 and anticipated capital expenditures. The ability to arrange sufficient and cost-effective financing is subject to numerous factors, including the regulatory environment in each of Alberta and British Columbia, the results of operations and financial position of each of the Alberta Utility and the B.C. Utility, conditions in the capital and bank credit markets, the 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.

Environmental Matters

The Alberta Utility and the B.C. Utility are subject to numerous laws, regulations and guidelines governing the management, transportation and disposal of hazardous substances and other waste materials and otherwise relating to the protection of the environment and health and safety. Potential environmental damage and costs could arise due to a severe weather event or a major equipment failure. However, there can be no assurance that such costs will be recoverable and, if substantial, unrecovered costs may have a material effect on the business, results of operations and prospects of the Alberta Utility or the B.C. Utility.

The Alberta Utility and the B.C. Utility are exposed to environmental risks that property owners in Alberta and British Columbia generally face. These risks include the responsibility of any property owner for the site remediation of any properties determined to be contaminated, whether or not such contamination was actually caused by the owner. Most of the B.C. Utility's generating and transmission facilities have been in place for many years with no apparent adverse environmental impact. However, as facilities are upgraded and as new facilities are added, environmental assessments and regulatory approvals will be required in the ordinary course.

Extreme climatic factors could potentially cause government authorities to adjust water flows on the Kootenay River in order to protect environmental values and could affect the amount of water available for generation either at the B.C. Utility's plants or at plants operated by parties contracted to supply energy to the B.C. Utility.

Alberta environmental and safety laws make owners, operators and persons in charge of management and control of facilities subject to prosecution or administrative action for breaches of environmental and safety laws, including the failure to obtain certificates of approval for the discharge of contaminants causing an adverse effect. The Alberta Utility has not been notified of any such regulatory action in regard to its operation or occupation of its facilities. However, it is not possible to predict with absolute certainty the position that a regulatory authority will take regarding matters of non-compliance with environmental and safety laws. Changes in environmental, health and safety regulations could also lead to significant increases in costs to the Alberta Utility.

Electricity transmission and distribution facilities have the potential to cause fires as a result of equipment failure, trees falling on a transmission or distribution line, or lightning strikes to wooden poles. Risks associated with fire damage are related to weather, the degree of forestation, habitation, and third party facilities located near the land on which the transmission facilities are situate. Each of the Alberta Utility and the B.C. Utility may be liable for fire-fighting costs and third party claims in connection with fires on these or other lands on which its transmission facilities are located, and such claims, if successful, could have a material effect on the business, results of operations and prospects of the Alberta Utility or the B.C. Utility.

Arthur Andersen

The Prospectus includes financial statements of the Alberta Utility for the year ended December 31, 2001 and the B.C. Utility for the years ended December 31, 2000 and 2001 that were audited and reported on by Arthur Andersen. The Corporation has not obtained the consent of Arthur Andersen to the use of its audit report in respect of these financial statements. Arthur Andersen's consent was not obtained because, on June 3, 2002, Arthur Andersen ceased to practice public accounting. Because Arthur Andersen has not provided this consent, purchasers of Subscription Receipts pursuant to the Prospectus will not have the statutory right of action for damages against Arthur Andersen as prescribed by applicable securities legislation with respect to these financial statements. In addition, Arthur Andersen may not have sufficient assets available to satisfy any judgments against it.

LEGAL MATTERS

Certain legal matters relating to the Offering will be passed upon on behalf of Fortis by Davies Ward Phillips & Vineberg LLP, Toronto, and Curtis, Dawe, St. John's and on behalf of the Underwriters by Stikeman Elliott LLP, Toronto. At the date hereof, partners and associates of each of Davies Ward Phillips & Vineberg LLP, Curtis, Dawe and Stikeman Elliott LLP own beneficially, directly or indirectly, less than one per cent of any securities of Fortis or any associate or affiliate of Fortis.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Ernst & Young LLP, The Fortis Building, 7th Floor, 139 Water Street, St. John's, Newfoundland and Labrador, are the auditors of the Corporation. The transfer agent and registrar for the Subscription Receipts is Computershare Trust Company in Toronto and Montréal.

STATUTORY RIGHTS OF WITHDRAWAL AND RESCISSION

Securities legislation in certain provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities within two business days after receipt or deemed receipt of the Prospectus and any amendments thereto. In several of the provinces, securities legislation further provides a purchaser with remedies for rescission or, in some provinces, damages where the short form prospectus and any amendments thereto contain a misrepresentation or are not delivered to the purchaser but such remedies must be exercised by the purchaser within the time limit prescribed by the securities legislation of such purchaser's province. Purchasers of Subscription Rights may no longer have remedies for rescission following the issuance of Common Shares upon surrender of the Subscription Receipts. Purchasers of Subscription Receipts will continue to have civil liability remedies, including remedies for damages that are provided to purchasers under securities legislation, in the event that the purchaser receives Common Shares upon surrender of Subscription Receipts. The purchaser should refer to any applicable provisions of the securities legislation of such purchaser's province for the particulars of these rights or consult with a legal advisor.

In addition, purchasers of the Subscription Receipts will have a contractual right of rescission following the issuance of the Common Shares to such purchaser. See ''Details of the Offering''.

In connection with the Offering, Fortis would normally be required to obtain a written consent from Arthur Andersen in order to include its audit report covering the audited financial statements of the Alberta Utility for the year ended December 31, 2001 and the B.C. Utility for the years ended December 31, 2000 and 2001 included in the Prospectus. However, on June 3, 2002, Arthur Andersen ceased to practice public accounting in Canada. As a consequence, representatives of Arthur Andersen are no longer available to provide a consent in connection with the filing of the Prospectus. As a result of Arthur Andersen not having provided its consent, purchasers of Subscription Receipts pursuant to the Prospectus will not be able to recover damages from Arthur Andersen under applicable securities legislation with respect to its audit report. Furthermore, Arthur Andersen may not possess sufficient assets to satisfy any claims that may arise out of its audit of the financial statements.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

The Prospectus, and the documents incorporated herein by reference, contain forward-looking statements which reflect management's expectations regarding the Corporation's future growth, results of operations, performance and business prospects and opportunities. Wherever possible, words such as ''anticipate'', ''believe'', ''expects'', ''intend'' and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to the Corporation's management. Forward-looking statements involve significant risk, uncertainties and assumptions. A number of factors could cause actual results, performance or achievements to differ materially from the results discussed or implied in the forward-looking statements. These factors should be considered carefully and prospective investors should not place undue reliance on the forward-looking statements. Although the forward-looking statements contained in the Prospectus, and the documents incorporated herein by reference, are based upon what management believes to be reasonable assumptions, the Corporation cannot assure prospective purchasers that actual results will be consistent with these forward-looking statements. These forward-looking statements are made as of the date of the Prospectus, and the Corporation assumes no obligation to update or revise them to reflect new events or circumstances.

GLOSSARY OF TERMS

In the Prospectus, unless the context otherwise requires, the following terms have the meanings set forth below.

''1933 Act'' means the United States *Securities Act of 1933*, as amended;

''Acquisition'' means the acquisition by the Corporation of all of the issued and outstanding shares of the Alberta Utility and the B.C. Utility;

''Acquisition Agreements'' means the Alberta Purchase Agreement and the B.C. Purchase Agreement;

''AEUB'' means the Alberta Energy and Utilities Board;

''Alberta Electricity Distribution Assets'' means the Alberta Utility's electricity distribution system;

''Alberta Purchase Agreement'' means the share purchase agreement dated as of September 15, 2003 between Fortis and ANCL for the purchase of all of the issued and outstanding shares, and the repayment of certain indebtedness, of the Alberta Utility;

''Alberta Utility'' means Aquila Networks Canada (Alberta) Ltd.;

''Alberta Utility Credit Facility'' means the commitment that the Corporation obtained from a Canadian chartered bank, for purposes of the Acquisition, to provide a $393 million non-revolving credit facility in favour of the Alberta Utility;

''ANBC'' means Aquila Networks British Columbia Ltd.;

''ANCL'' means Aquila Networks Canada Ltd.;

''Aquila'' means Aquila, Inc.;

''B.C. Electricity Generation, Transmission and Distribution Assets'' means the B.C. Utility's integrated utility assets;

''B.C. Purchase Agreement'' means the share purchase agreement dated as of September 15, 2003 between Fortis and ANBC for the purchase of all of the issued and outstanding shares, and the repayment of certain indebtedness, of the B.C. Utility;

''B.C. Utility'' means Aquila Networks Canada (British Columbia) Ltd.;

''B.C. Utility Credit Facility'' means the commitment that the Corporation obtained from a Canadian chartered bank, for purposes of the Acquisition, to provide a $277 million non-revolving credit facility in favour of the B.C. Utility;

''BCUC'' means the British Columbia Utilities Commission;

''CDS'' means The Canadian Depository for Securities Limited;

''CDS Participant'' means a registered dealer who is a CDS participant from or through whom Subscription Receipts may be purchased or transferred;

''Central Newfoundland Energy'' means Central Newfoundland Energy Inc.;

''Closing Date'' means October 8, 2003 or such other date as agreed to by the Corporation and the Underwriters, but not later than November 7, 2003;

''Corporation'' means Fortis Inc.;

''Credit Facilities'' means, collectively, the Fortis Credit Facility, the Alberta Utility Credit Facility and the B.C. Utility Credit Facility;

''Escrow Agent'' means Computershare Trust Company of Canada or its successor as escrow agent under the Subscription Receipt Agreement;

''Escrowed Funds'' means the gross proceeds from the sale of the Subscription Receipts;

''EUA'' means the *Electric Utilities Act* (Alberta);

''Fortis'' means Fortis Inc.;

''Fortis Credit Facility'' means the commitment that the Corporation obtained from a Canadian chartered bank, for purposes of the Acquisition, to provide a $730 million non-revolving credit facility in favour of the Corporation;

''Offering'' means the distribution of Subscription Receipts pursuant to the Prospectus;

''Prospectus'' means this short form prospectus;

''Release Conditions'' means the receipt by the Corporation of all regulatory and government approvals required to finalize the Acquisition, including those of AEUB and BCUC, and fulfillment or waiver of all other outstanding conditions precedent to closing the Acquisition as itemized in the Acquisition Agreements;

''SEDAR'' means the Canadian System for Electronic Document Analysis and Retrieval;

''Subscription Receipt Agreement'' means the agreement dated as of the Closing Date among the Corporation, Scotia Capital Inc. and the Escrow Agent governing the terms of the Subscription Receipts;

''Subscription Receipts'' means the subscription receipts of the Corporation offered hereby;

''Termination Time'' means the earlier of 5:00 p.m. (Toronto time) on June 30, 2004 or the date on which either of the Alberta Purchase Agreement or the B.C. Purchase Agreement is terminated;

''TSX'' means the Toronto Stock Exchange;

''Underwriters'' means Scotia Capital Inc., BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc. and Beacon Securities Limited;

''Underwriting Agreement'' means the underwriting agreement dated September 29, 2003, between the Corporation and the Underwriters relating to the sale of the Subscription Receipts offered under the Prospectus; and

''Vendors'' mean ANCL and ANBC.

All dollar amounts in the Prospectus are expressed in Canadian dollars.

INDEX TO FINANCIAL STATEMENTS

PRO FORMA CONSOLIDATED
FINANCIAL STATEMENTS

FORTIS INC.

Unaudited — See Compilation Report

As at June 30, 2003 and for the six-month period ended
June 30, 2003 and the year ended December 31, 2002

COMPILATION REPORT

To the Board of Directors of
Fortis Inc.

We have reviewed, as to compilation only, the accompanying pro forma consolidated balance sheet of **Fortis Inc.** as at June 30, 2003 and the pro forma consolidated statements of earnings for the six-month period ended June 30, 2003 and for the year ended December 31, 2002, which have been prepared for inclusion in the Company's short form prospectus dated September 29, 2003 relating to issuance of subscription receipts. In our opinion, the pro forma consolidated balance sheet and pro forma consolidated statements of earnings have been properly compiled to give effect to the proposed transactions and the assumptions described in the accompanying notes thereto.

St. John's, Canada,
September 29, 2003.

(Signed) *ERNST & YOUNG LLP*
Chartered Accountants

Fortis Inc.

PRO FORMA CONSOLIDATED BALANCE SHEET
As at June 30, 2003
(Unaudited)
(in thousands of dollars)

	Fortis Inc.	ANCA	ANCBC	Pro forma adjustments		Pro forma consolidated balance sheet
	$	$	$	Note	$	$
ASSETS						
Current						
Cash and cash equivalents	34,222	12,034	195		—	**46,451**
Receivables	142,221	58,343	47,499		—	**248,063**
Materials and supplies	17,184	10,822	4,664		—	**32,670**
Current portion of regulatory cost deferral	—	69,492	—		—	**69,492**
	193,627	150,691	52,358		—	**396,676**
Corporate income tax deposit	6,949	—	—		—	**6,949**
Cash held in escrow	5,092	—	—		—	**5,092**
Deferred charges	104,847	—	13,988	2[g]	10,000	**128,835**
Future income taxes	—	2,962	—	2[b]	9,149	**17,207**
				2[f]	5,096	
Utility capital assets, net	1,211,798	440,159	427,715		—	**2,079,672**
Income producing properties	289,353	—	—		—	**289,353**
Investments	166,106	—	—		—	**166,106**
Intangibles, net of amortization	23,981	—	—		—	**23,981**
Goodwill	65,435	189,309	—	2[b]	318,135	**572,879**
	2,067,188	783,121	494,061		342,380	**3,686,750**
LIABILITIES						
Current						
Short-term borrowings	118,046	99,859	42,935		—	**260,840**
Accounts payable and accrued charges	131,012	115,019	45,402		—	**291,433**
Current portion of long-term debt	27,742	—	—		—	**27,742**
Current installments securitization financing	—	99,196	—		—	**99,196**
Future income taxes	8,971	—	—		—	**8,971**
	285,771	314,074	88,337		—	**688,182**
Long-term debt	934,438	230,000	225,340	2[a]	394,000	**1,807,778**
				2[e]	24,000	
Deferred credits	62,131	950				**63,081**
Future income taxes	25,799	—	1,765		—	**27,564**
Non-controlling interest	35,809	—	—		—	**35,809**
	1,343,948	545,024	315,442		418,000	**2,622,414**
SHAREHOLDERS' EQUITY						
Common shares	326,468	347,579	76,500		(424,079)	**667,564**
				2[f]	341,096	
Preference shares	122,992	—	—		—	**122,992**
Contributed surplus	516	—	—		—	**516**
Equity portion of convertible debentures	1,738	—	—		—	**1,738**
Foreign currency translation adjustment	(9,067)	—	—		—	**(9,067)**
Retained earnings	280,593	(109,482)	102,119		7,363	**280,593**
	723,240	238,097	178,619		(75,620)	**1,064,336**
	2,067,188	783,121	494,061		342,380	**3,686,750**

See accompanying notes

Fortis Inc.

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS
For the year ended December 31, 2002
(Unaudited)
(in thousands of dollars, except for per share amounts)

	Fortis Inc.	ANCA	ANCBC	Pro forma adjustments		Pro forma consolidated statement of earnings
	$	$	$	Note	$	$
Operating Revenues	715,465	268,536	153,994		—	**1,137,995**
Expenses						
Operating	476,969	100,117	109,072		—	**686,158**
Amortization	65,063	82,578	14,685	2[g]	1,000	**163,326**
	542,032	182,695	123,757		1,000	**849,484**
Net Operating Income	173,433	85,841	30,237		(1,000)	**288,511**
Finance Charges						
Interest	70,728	24,924	14,341	2[d]	25,610	**135,603**
Dividends on preference shares	2,736	—	—		—	**2,736**
	73,464	24,924	14,341		25,610	**138,339**
Earnings Before Undernoted Items, Income Taxes and Non-Controlling Interest	99,969	60,917	15,896		(26,610)	**150,172**
Impairment in the carrying value of the Walden Power Plant	—	—	10,000		—	**10,000**
Earnings Before Income Taxes and Non-Controlling Interest	99,969	60,917	5,896		(26,610)	**140,172**
Income Taxes	32,488	33,376	(242)	2[h]	(10,676)	**54,946**
Earnings Before Non-Controlling Interest	67,481	27,541	6,138		(15,934)	**85,226**
Non-controlling interest	4,229	—	—		—	**4,229**
Earnings Applicable to Common Shares	63,252	27,541	6,138		(15,934)	**80,997**
Average Common Shares Outstanding	16,277			2[f]	6,306	**22,583**
Earnings per Common Share						
Basic	3.89	—	—	2[i]	—	**3.58**
Diluted	3.85	—	—		—	**3.54**

See accompanying notes

Fortis Inc.

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS
For the six month period ended June 30, 2003
(Unaudited)
(in thousands of dollars, except for per share amounts)

	Fortis Inc.	ANCA(1)	ANCBC	Pro forma adjustments		Pro forma consolidated statement of earnings
	$	$	$	Note	$	$
Operating Revenues	441,011	70,073	82,014		—	**593,098**
Expenses						
Operating	299,360	45,281	55,342		—	**399,983**
Amortization	34,946	4,222	7,208	2[g]	500	**46,876**
	334,306	49,503	62,550		500	**446,859**
Net Operating Income	106,705	20,570	19,464		(500)	**146,239**
Finance Charges						
Interest	40,272	12,235	7,376	2[d]	12,805	**72,688**
Earnings Before Undernoted Items, Income Taxes and Non-Controlling Interest	66,433	8,335	12,088		(13,305)	**73,551**
Goodwill impairment	—	80,000(1)	—		—	**80,000**
Earnings (Loss) Before Income Taxes and Non-Controlling Interest	66,433	(71,665)	12,088		(13,305)	**(6,449)**
Income Taxes	23,493	(5,462)	3,174	2[h]	(5,072)	**16,133**
Earnings (Loss) Before Non-Controlling Interest	42,940	(66,203)	8,914		(8,233)	**(22,582)**
Non-controlling interest	1,623	—	—		—	**1,623**
Earnings (Loss)	41,317	(66,203)	8,914		(8,233)	**(24,205)**
Dividends on preference shares	560	—	—		—	**560**
Earnings (Loss) Applicable to Common Shares	40,757	(66,203)	8,914		(8,233)	**(24,765)**
Average Common Shares Outstanding	17,270	—	—	2[f]	6,306	**23,576**
Earnings (Loss) per Common Share						
Basic	2.36	—	—	2[i]		**(1.05)**
Diluted	2.33	—	—			**(1.05)**

(1) Refer to the ANCA interim financial statements for the period ended June 30, 2003 for explanation of the results.

See accompanying notes

Fortis Inc.

NOTES TO PRO FORMA CONSOLIDATED FINANCIAL STATEMENTS (amounts are expressed in thousands of dollars)

(Unaudited)

1. BASIS OF PRESENTATION

The accompanying pro forma consolidated financial statements give effect to the acquisition of all of the issued and outstanding shares in Aquila Networks Canada (Alberta) Ltd. (''ANCA'') and Aquila Networks Canada (British Columbia) Ltd. (''ANCBC'') as described in the short form prospectus dated September 29, 2003, (the ''Prospectus''). The accompanying pro forma consolidated financial statements have been prepared by Management of Fortis Inc. (''Fortis'' or the ''Company'') and are derived from the unaudited and audited consolidated financial statements of Fortis as at and for the six month period ended June 30, 2003 and for the year ended December 31, 2002, respectively; the unaudited and audited financial statements of ANCA as at and for the six month period ended June 30, 2003, and for the year ended December 31, 2002, respectively; and the unaudited and audited financial statements of ANCBC as at and for the six month period ended June 30, 2003 and for the year ended December 31, 2002, respectively.

The accounting policies used in the preparation of these pro forma consolidated financial statements are those disclosed in the Company's audited financial statements. Management has determined that no adjustments to ANCA's and ANCBC's financial statements are required to comply with the accounting policies used by Fortis in the preparation of its consolidated financial statements.

As is standard with similar transactions in regulated utilities, the purchase price is primarily based upon the regulated assets at the point of closing. Based on the purchase price calculation as detailed in the purchase and sale agreements dated September 15, 2003, the estimated net purchase price of ANCA and ANCBC is $720,000 (refer to note 2a) and is based on managements' estimate of working capital, capital assets and debt levels at December 31, 2003. Under the terms of the purchase and sale agreements, the final purchase price is to be adjusted for changes in working capital, capital assets and debt levels from these estimates.

The pro forma consolidated balance sheet and pro forma consolidated statements of earnings reflect the acquisition effected June 30, 2003 and January 1, 2002, respectively. The pro forma consolidated financial statements are not necessarily indicative of the results that actually would have been achieved if the transactions reflected therein had been completed on the dates indicated or the results which may be obtained in the future. The primary variance relates to;

- The estimated net purchase price of $720,000, which is based on the expected levels of capital assets, working capital and debt at December 31, 2003, has been applied to the pro forma consolidated statements of earnings effective January 1, 2002. Had the purchase price been adjusted to reflect the actual level of working capital, capital assets and debt existing at that time, the net purchase price would have been $449,000 and the after-tax interest expense would have decreased by approximately $10,500 and $5,500 for the year-ended December 31 2002 and for the six-month period ended June 30, 2003, respectively.
- The actual purchase price allocation will reflect the fair value, at the purchase date, of the assets acquired and liabilities assumed based upon the acquirer's evaluation of such assets and liabilities following the closing of the transaction and, accordingly, the final purchase price allocation, as it relates principally to intangible assets, may differ significantly from the preliminary allocation reflected herein.

These pro forma consolidated financial statements should be read in conjunction with the description of the transactions described in the Prospectus; the audited and unaudited financial statements of ANCA, including the notes thereto, included in the Prospectus; the unaudited and audited financial statements of ANCBC, including the notes thereto, included in the Prospectus; and the unaudited and audited consolidated financial statements of Fortis including the notes thereto, incorporated by reference in the Prospectus.

2. PRO FORMA ASSUMPTIONS AND ADJUSTMENTS

These pro forma consolidated financial statements give effect to the completion of the acquisition of ANCA and ANCBC, as if it had occurred on June 30, 2003 in respect of the pro forma consolidated balance sheet, and on January 1, 2002 with respect to the pro forma consolidated statement of earnings for the year ended December 31, 2002 and for the six-month period ended June 30, 2003. The proposed acquisition has been reflected in the pro forma consolidated financial statements using the purchase method. For purposes of the preparation of the pro forma-consolidated statements of earnings, this transaction is deemed effective on January 1, 2002 using the estimated net purchase price at December 31, 2003.

[a] Estimated Net Purchase Price as of December 31, 2003(1)

	$
Unadjusted purchase price	1,360,000
Working capital and other adjustments	39,000(1)
Estimated acquisition costs (note 2[g])	10,000
Estimated net purchase price, before assumed debt, as of December 31, 2003	1,409,000
Assumed debt of ANCA and ANCBC	(689,000)(1)
Estimated net purchase price as of December 31, 2003	720,000

Estimated Net Funding Requirements as of December 31, 2003

	$
Estimated Net Purchase Price	720,000
Assumed debt of ANCA and ANCBC (to be refinanced)	689,000
Other Costs	
Acquisition Financing Costs	10,000
Common Share Issuance Costs	14,000
Estimated Net Funding Requirements as of December 31, 2003	1,433,000

Assumed Financing Structure as of December 31, 2003

	$
Assumed debt of ANCA and ANCBC	689,000
Common share issuance	350,000
Incremental long-term debt issuance	394,000
	1,433,000

(1) Adjustments based on estimated financial position of ANCA and ANCBC as of December 31, 2003.

[b] Allocation of estimated net purchase price

The estimated net purchase price, which is based on the expected level of capital assets, working capital and debt at December 31, 2003, has been allocated to the fair values of ANCA and ANCBC net assets and liabilities at June 30, 2003, in accordance with the purchase method, as follows:

	ANCA	ANCBC	Total
	$	$	$
Assets acquired:			
Cash and cash equivalents	12,034	195	**12,229**
Receivables	58,343	47,499	**105,842**
Material and supplies	10,822	4,664	**15,486**
Regulatory cost deferral	69,492	—	**69,492**
Current assets	150,691	52,358	**203,049**
Other assets	—	13,988	**13,988**
Future income taxes	2,962	9,149(i)	**12,111**
Utility capital assets	440,159	427,715	**867,874**
	593,812	503,210	**1,097,022**
Liabilities assumed:			
Current portion of long-term debt	99,859	42,935	**142,794**
Accounts payable and accrued charges	115,019	45,402	**160,421**
Other liabilities	950	—	**950**
Future income taxes	—	1,765	**1,765**
Securitization financing	99,196	—	**99,196**
Long-term debt	230,000	249,340(i)	**479,340**
	545,024	339,442	**884,466**
Net assets at fair value, June 30, 2003	48,788	163,768	**212,556**
Net purchase price			**720,000**
Goodwill			**507,444**
Goodwill previously recorded by ANCA			**(189,309)(iii)**
Additional goodwill			**318,135(ii)**

(i) Fair value of the assumed ANCBC debentures exceed book value by approximately $24,000. The future tax asset associated with the fair value increment is $9,149.

(ii) The $720,000 estimated net purchase price, which is based on estimated financial information as of December 31, 2003, has been applied to the net assets as at June 30, 2003. Had the purchase price been calculated based on the working capital, capital asset and debt levels at June 30, 2003, the goodwill would have decreased by approximately $87,000.

(iii) The goodwill recorded by ANCA was created when Aquila purchased the distribution and retail assets of TransAlta Utilities Corporation (''TransAlta'').

[c] Goodwill

The excess of the purchase price over the fair value of net assets acquired from ANCA and ANCBC is not amortized. In accordance with the CICA standard, goodwill is no longer amortized to earnings, instead, will be assessed for impairment at least annually.

[d] Financing

The Company has entered into a bridge financing agreement with its bankers for up to $1,400,000 at an assumed rate of 6.5%. This bridge will be refinanced with the issuance of common shares and other permanent capital including long-term debt facilities. It is assumed the total anticipated funding requirement of $1,433,000 will be initially financed by the bridge acquisition facility and the assumed debt will be subsequently refinanced at an average rate of 6.5%.

Additional interest expense of the following has been assumed:

	Six month period ended June 30, 2003	Year ended December 31, 2002
	$	$
Interest on $394,000 incremental debt at 6.5%	**12,805**	**25,610**

[e] Assumed ANCBC Debentures

ANCBC has debentures outstanding of $148,300, in various series with due dates ranging from 2009 to 2023. The rates range from 6.75% to 11%, resulting in the fair market value of the debentures exceeding book value by $24,000, calculated as at December 31, 2002. This fair value increment is assumed constant and is applied to the June 2003 pro forma consolidated balance sheet.

[f] Common share issuance

To fund a portion of the acquisition purchase price, the Corporation plans to issue approximately 6,306,300 common shares on closing resulting in estimated gross proceeds of $350,000 and net proceeds after common share issuance costs of $341,096. ($14,000 common share issuance costs less $5,096 income taxes). The current approximate market price per share has been applied as the issue price per share in the pro forma consolidated financial statements.

[g] Acquisition and financing costs

It is assumed acquisition costs will approximate $10,000, and will form part of the investment cost base. Financing costs are assumed to approximate $10,000, and will be deferred and amortized over 10 years.

[h] Income taxes

Income taxes applicable to the pro forma adjustments are tax effected at Fortis' average tax rates of 40.12% and 38.12% for the year ended December 31, 2002 and the six month period ended June 30, 2003, respectively.

[i] Earnings per share

The calculation of the pro forma earnings per share for the year ended December 31, 2002, and for the six-month period ended June 30, 2003, considers the issuance of 6,306,300 common shares as contemplated in the Prospectus dated September 29, 2003, as if the issuance had taken place as at January 1, 2002.

Aquila Networks Canada (Alberta) Ltd.

Formerly UtiliCorp Networks Canada (Alberta) Ltd.

Financial Statements
December 31, 2002 and 2001

Together with Auditors' Report

AUDITORS' REPORT

To the Directors of
Aquila Networks Canada (Alberta) Ltd.,

We have audited the balance sheet of **AQUILA NETWORKS CANADA (ALBERTA) LTD.** as at December 31, 2002 and the statements of operations, deficit and cash flows for the year 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 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 Company as at December 31, 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The financial statements as at December 31, 2001 and for the year then ended, prior to the restatement of transmission revenues and expenses as described in Note 2, were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those financial statements in their report dated February 5, 2002. We have audited the restatement of transmission revenues and expenses in the 2001 statement of operations and in our opinion, such restatement, in all material respects, is appropriate and properly applied.

Calgary, Canada
January 31, 2003

(Signed) *KPMG LLP*
Chartered Accountants

Aquila Networks Canada (Alberta) Ltd.

BALANCE SHEETS
As at December 31
(All dollar amounts are in thousands)

	2002	2001
	$	$
ASSETS		
PROPERTY, PLANT AND EQUIPMENT, net of accumulated amortization (Notes 3 and 12)	505,927	496,885
Regulatory tax basis adjustment, net of accumulated amortization (Note 4)	(116,766)	(122,583)
	389,161	374,302
REGULATORY COST DEFERRAL (Note 5)	12,882	162,260
GOODWILL, net of accumulated amortization (Note 2)	269,309	278,032
FUTURE INCOME TAX (Note 13)	2,962	—
CURRENT ASSETS		
Accounts receivable (Notes 10, 12 and 15)	43,506	64,576
Current portion of regulatory cost deferral (Note 5)	116,664	120,368
Supplies	10,709	9,821
Regulatory deferred charges	1,996	1,268
	172,875	196,033
	847,189	1,010,627
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION (Note 6)		
SHAREHOLDER'S EQUITY		
Share capital	347,579	383,579
Deficit	(43,279)	(70,550)
Total shareholder's equity	304,300	313,029
DEBT	230,000	236,940
	534,300	549,969
LIABILITIES		
SECURITIZATION FINANCING (Note 8)	25,346	—
OTHER OBLIGATIONS (Note 9)	—	90,174
FUTURE INCOME TAX (Note 13)	—	45,979
CONTINGENCIES AND COMMITMENTS (Notes 10 and 14)		
CURRENT LIABILITIES		
Accounts payable (Note 12)	61,245	64,203
Current portion of debt	6,940	58,675
Current portion of securitization financing	144,477	—
Short-term debt (Note 7)	—	106,970
Current portion of other obligations	—	90,174
Income taxes payable	74,881	4,483
	287,543	324,505
	847,189	1,010,627

Approved on behalf of the Board:

(Signed) *Fauzia Lalani*, Director

(Signed) *Steve Raniseth*, Director

The accompanying notes are an integral part of these financial statements.

Aquila Networks Canada (Alberta) Ltd.

STATEMENTS OF OPERATIONS
For the year ended December 31
(All dollar amounts are in thousands)

	2002	2001
	$	$
REVENUES		
Electric rate revenue (Note 10)	248,092	243,146
Other (Note 5)	20,444	9,966
	268,536	253,112
EXPENSES		
Depreciation and amortization	82,578	81,304
Operating labour	46,528	48,000
Contracted services (Note 12)	24,235	23,274
General operating expenses	20,465	18,561
Taxes other than income taxes	6,889	6,687
Regulatory deferred charges	2,000	—
	182,695	177,826
EARNINGS FROM OPERATIONS	85,841	75,286
INTEREST EXPENSE	24,924	37,896
INCOME BEFORE INCOME TAXES	60,917	37,390
INCOME TAXES (Note 13)	33,376	25,242
NET EARNINGS	27,541	12,148

CONSOLIDATED STATEMENTS OF DEFICIT
For the year ended December 31
(All dollar amounts are in thousands)

	2002	2001
	$	$
DEFICIT, BEGINNING OF YEAR	(70,550)	(82,698)
Net earnings	27,541	12,148
Dividends	270	—
DEFICIT, END OF YEAR	(43,279)	(70,550)

The accompanying notes are an integral part of these financial statements.

Aquila Networks Canada (Alberta) Ltd.

STATEMENTS OF CASH FLOWS
For the year ended December 31
(All dollar amounts are in thousands)

	2002	2001
	$	$
OPERATING ACTIVITIES		
Net earnings	27,541	12,148
Add items not involving cash		
Depreciation and amortization	82,578	81,304
Amortization of deferred charges	1,078	2,666
Future income taxes	(48,941)	18,189
Collection of regulatory cost deferral	153,080	102,906
	215,336	217,213
Change in non-cash working capital related to operating activities	100,520	(265,566)
	315,856	(48,353)
INVESTING ACTIVITIES		
Additions to property, plant and equipment	(103,538)	(96,399)
Additions to deferred charges	(3,935)	—
Change in non-cash working capital related to investing activities	—	(20,884)
Purchase price adjustments (Note 1)	4,057	—
	(103,416)	(117,283)
FINANCING ACTIVITIES		
Proceeds of note payable to Aquila Networks Canada Finance Limited Partnership	—	230,000
Repayment of debt	(58,675)	(313,715)
Proceeds from securitization financing	255,000	—
Repayments of securitization financing	(85,177)	—
Repayment of note payable to Aquila Networks Canada Corp.	—	(202,482)
Proceeds (repayment) of other obligations	(180,348)	41,256
Proceeds (repayment) of commercial paper	(106,000)	106,000
Proceeds (repayment) of line of credit	(970)	970
Financing charges	—	(3,489)
Issue of common shares, net of redemptions	(36,000)	66,000
Dividends	(270)	—
Change in non-cash working capital related to financing activities	—	(6,016)
	(212,440)	(81,476)
DECREASE IN CASH AND CASH EQUIVALENTS	—	(247,112)
CASH AND CASH EQUIVALENTS, beginning of year	—	247,112
CASH AND CASH EQUIVALENTS, end of year	—	—
Cash flows include the following elements:		
Interest paid	24,924	43,912
Income taxes paid	11,670	2,815

The accompanying notes are an integral part of these financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the year ended December 31, 2002 and 2001
(All tabular dollar amounts are in thousands, unless otherwise noted)

1. ENTITY DEFINITION AND NATURE OF OPERATIONS

Aquila Networks Canada (Alberta) Ltd. (''ANCA'' or the ''Company'') (formerly UtiliCorp Networks Canada (Alberta) Ltd.) was incorporated under the laws of Alberta for the initial purpose of acquiring the distribution and retail operations of TransAlta Utilities Corporation (''TAU''), pursuant to an asset transfer agreement, which had an effective closing date of August 31, 2000. The Company was acquired by an indirect wholly owned subsidiary of Aquila, Inc. (''Aquila''), a U.S. public company, on August 31, 2000. The consideration paid for this acquisition has been recorded in these financial statements using push-down accounting (see Note 6).

Effective January 1, 2001, the Company disposed of its retail operations and related assets and began operating solely as an owner and operator of distribution assets. As a distribution company, ANCA invoices retail energy companies for the distribution and transmission portions of electricity rates. In turn, the Company is invoiced by the transmission administrator for the transmission services.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation

The Company is regulated by the Alberta Energy and Utilities Board (''AEUB''). The AEUB administers acts and regulations covering such matters as tariffs, rates, construction, operations, financing and accounting. The timing of ANCA's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian generally accepted accounting principles for entities not subject to rate regulation.

Use of estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosures with respect to contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the period. Certain estimates are necessary since the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until finalization, and adjustments, if any, are determined pursuant to subsequent regulatory decisions or other regulatory proceedings. Due to the inherent uncertainty in making such estimates, actual results reported in future periods could differ materially from those estimated. See also Note 10 for specific commentary regarding revenue estimates.

Revenue recognition

As required by the AEUB, revenues are recognized on a billing cycle basis, at AEUB approved rates.

On January 1, 2002, the Company adopted Canadian Institute of Chartered Accountants Emerging Issues Committee Abstract 123. This abstract requires the Company to report revenues and expenses related to transmission services on a net basis. The Company has retroactively adopted the provisions of this abstract, resulting in the netting of prior year transmission service expense and electric rate revenue of $155.2 million.

Property, plant and equipment

Property, plant and equipment are carried at cost including an allowance for funds used during construction. The cost of amortizable assets retired together with removal costs less salvage value is charged to accumulated amortization.

Amortization is provided on a straight-line basis calculated on the investment in amortizable assets in service. Rates are designed to amortize the cost of the assets over their estimated service life. The application of these rates, as approved by the AEUB, for the period ended December 31, 2002 results in an annualized composite amortization rate of 5.66% (2001 — 5.64%).

Customers' portion of costs

Certain additions to property, plant and equipment are made with the assistance of non-refundable contributions from customers when the estimated revenue is less than the cost of providing service or where special equipment is needed to supply the customers' specific requirements. Such amounts are recorded as a reduction of property, plant and equipment and are being amortized over the estimated service lives of the related assets by an offset against the provision for amortization.

Income taxes

The Company follows the taxes payable method of accounting for income taxes, consistent with the method and timing for determining the income tax component of its rates as regulated by the AEUB, except as described in Note 13. Future income taxes are generally recognized only to the extent they will not be recoverable in future rates charged to customers.

Cash and cash equivalents

Cash and cash equivalents are comprised of cash and highly liquid investments with original maturities of 90 days or less.

Goodwill

Effective January 1, 2002, the Company adopted Canadian Institute of Chartered Accountants Handbook Section 3062 ''Goodwill and Other Intangible Assets'' and will no longer amortize goodwill. However, goodwill is subject to an impairment test at least annually or upon a significant potential impairment event. Prior to January 1, 2002, goodwill was amortized on a straight-line basis over 40 years. Amortization expense for the year ended December 31, 2001 was $8.3 million.

As at January 1 and November 30, 2002, a goodwill impairment test was performed and it was determined that there is no impairment of goodwill.

Employee future benefits

The Company records the costs of employee future benefits as employer contributions are paid. This is consistent with the method required by AEUB regulation for including employee future benefits in rates charged to customers. A measurement date of September 30 is used for the Company's pension plan assets and obligations.

3. PROPERTY, PLANT AND EQUIPMENT

The cost and accumulated amortization of property, plant, and equipment has been presented using TAU's historic amounts as they form the basis used to determine amortization for regulatory purposes.

	2002			2001
	Cost	Accumulated Amortization	Net Book Value	Net Book Value
	$	$	$	$
Distribution network	1,826,907	(1,079,527)	747,380	743,882
Construction in progress	10,351	—	10,351	4,320
Customer contributions	(426,311)	174,507	(251,804)	(251,317)
	1,410,947	(905,020)	505,927	496,885

During the year ended December 31, 2002, interest of $nil (2001 — $0.3 million) was capitalized to construction in progress.

4. REGULATORY TAX BASIS ADJUSTMENT

The regulatory tax basis adjustment represents the excess of the deemed tax basis of the Company's property, plant and equipment 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 property, plant and equipment by an offset against the provision for depreciation and amortization. During 2002, depreciation and amortization expense was reduced by $5.8 million (2001 — $5.5 million) for the amortization of the regulatory tax basis adjustment.

5. REGULATORY COST DEFERRAL

The Electric Utilities Act of Alberta (''EUA'') governs the exchange of all electric energy through the interconnected electric system in the Province of Alberta. Pursuant to the EUA, the dispatch and exchange of electric energy and the financial settlement for the exchange of electric energy in Alberta is conducted through the Power Pool of Alberta (the ''Power Pool''). The EUA also mandates the use of an independent transmission administrator to administer the transmission of all electric energy through the province. The cost of transmission service is partially tied to the cost of electric energy as determined by the Power Pool.

During 2000, the pool price charged to ANCA and TAU for electric energy exceeded the AEUB approved forecast commodity pool price that was used to set regulated retail electricity rates for the 2000 calendar year. As a result, the Company incurred expenditures related to the purchases of both commodity and transmission services that exceeded the level of revenue received from customers for these costs (the ''excess costs''). Excess costs deferred in this manner have been reflected as regulatory cost deferral in these financial statements.

During 2001, the Company was directed by the AEUB to collect its regulatory cost deferral during 2001 to 2003. In addition, as a result of an AEUB decision, the Company is entitled to recover its financing costs related to the regulatory cost deferral, based on a carrying cost recovery rate of 7.90% in 2001 and 6.45% for the period of January 1 to August 15, 2002. Included in 2002 electric rate revenue for the year ended December 31, 2002 is $3.6 million (December 31, 2001 — $19.1 million) related to the recovery of regulatory cost deferral financing costs.

In June 2002, the AEUB authorized the Company to enter into a securitization agreement whereby the deferral accounts could be sold to an unrelated financial institution (the ''Purchaser''). On August 15, 2002, the Company completed the securitization of its deferral accounts for proceeds of $255 million. This represented the balance of certain components of the regulatory cost deferral as at July 1, 2002. Under the terms of the agreement, the deferral accounts were sold to a third party for cash proceeds of $255 million. The Company will continue to service the deferral accounts and accordingly will bill, collect, and between settlement dates, hold rate riders in trust for the purchaser.

Notwithstanding that the Purchaser has acquired all benefits associated with the deferral accounts, the deferral accounts do not meet the accounting definition of a financial asset eligible for sale accounting and accordingly, the transaction has been recorded as a financing in these financial statements.

The net proceeds of the securitization were used to pay amounts due to TAU (Note 9) and redeem common shares in the amount of $51 million, with the remainder being used to retire commercial paper outstanding and for general corporate purposes.

The regulatory cost deferral is comprised as follows:

	Commodity	Generation Entitlements	Transmission Service	Other	Total
	$	$	$	$	$
Balance at December 31, 2001	285,361	44,805	(49,375)	1,837	282,628
Recovered through 2002 riders	(168,986)	(26,815)	18,183	—	(177,618)
Net 2002 revision to 2001 balances as a result of 2002 AEUB decisions	2,887	2,166	—	(3,503)	1,550
2002 excess transmission costs	—	—	22,986	—	22,986
Balance at December 31, 2002	119,262	20,156	(8,206)	(1,666)	129,546
Less: current portion	(106,380)	(20,156)	8,206	1,666	(116,664)
	12,882	—	—	—	12,882

Effective January 1, 2001, as a result of disposing of its retail operations, the Company became solely a distribution system owner and is no longer responsible for the purchase of electric energy. Accordingly, no excess commodity costs were incurred in 2001 or 2002. However, the Company continues to defer excess or deficient transmission service costs and expects that the 2001 and 2002 amounts will be refunded in subsequent periods.

Included in other revenue in 2002 is $10.3 million (2001 — $nil) related to transmission services expense originally recognized in 2000 but reversed in 2002 due to favorable regulatory decisions.

6. CAPITALIZATION

(a) Share Capital

Authorized — unlimited number of:

Common shares
Class A Common shares
First Preferred non-voting shares, redeemable, cumulative dividend at 10% of the redemption price

Issued — 63 Class A Common shares (710 Class A Common shares in 2001)

	2002	2001
	$	$
Common shares	138,848	174,848
Contributed surplus	208,731	208,731
	347,579	383,579

During 2002 the Company's parent subscribed for an additional 13 Class A Common shares for cash consideration of $30 million. The Company also redeemed 660 shares for cash consideration of $66 million. During 2001 the Company issued 1,050 Class A Common shares for cash consideration of $105 million and subsequently redeemed 390 Class A Common shares for $39 million.

Contributed surplus relates to the push-down of the purchase price premium paid by the Company's parent on acquisition of TAU's retail and distribution assets.

(b) Debt

	2002	2001
	$	$
Note Payable — Aquila Networks Canada Finance Limited Partnership	230,000	230,000
Notes payable to various Rural Electrification Associations	6,940	17,415
Term bank facility	—	48,200
	236,940	295,615
Current portion	(6,940)	(58,675)
	230,000	236,940

The note payable to Aquila Networks Canada Finance Limited Partnership, an affiliated company, bears interest at 8.66%, is unsecured and is due on June 15, 2011.

Notes payable to various Rural Electrification Associations are unsecured and bear interest, determined at January 1 and July 1 of each year, at the greater of the prevailing bank prime interest rate or the five-year bank term deposit rate, and are due on demand. The effective interest rate for the year ended December 31, 2002 was 4.13% (6.88% in 2001).

Included within interest expense is $22.8 million related to long-term debt.

During the year ended December 31, 2002, the Company recorded interest expense on its note payable to Aquila Networks Canada Finance Limited Partnership of $19.9 million (2001 — $10.6 million).

7. SHORT-TERM DEBT

	2002	2001
	$	$
Commercial paper and credit facility	—	106,000
Revolving demand lines of credit	—	970
	—	106,970

The Company's commercial paper program provides for maximum borrowing of $112.5 million. ANCA has arranged a $112.5 million committed revolving facility which matures June 17, 2003 to support the commercial paper program. To the extent commercial paper has been issued, the amount of the committed revolving facility available is reduced.

The Company has also arranged a $30 million unsecured revolving demand facility, which is made available by prime loans or Bankers' Acceptances. As at December 31, 2002, $17.7 million of this facility has been utilized for outstanding letters of credit.

8. SECURITIZATION FINANCING

	2002	2001
	$	$
Securitization financing	169,823	—
Current portion	(144,477)	—
	25,346	—

The Company sold certain components of its regulatory cost deferral on August 15, 2002 (Note 5). The transaction has been treated as a financing for accounting purposes, and accordingly, securitization financing represents the cash received from the financial institution less repayments to date. The notional interest rate on the securitization financing is 3.45%.

9. OTHER OBLIGATIONS

Amounts due to TAU were unsecured and were payable upon receipt of the proceeds on securitization of the Company's regulatory cost deferral (see Note 5).

10. REVENUE MEASUREMENT

(a) Regulated rates

The regulatory process with respect to final 2002 distribution rates is not complete. The Company has applied for a 8.7% increase in 2002 rates compared to 2001. Effective July 1, 2002 the Company received approval to collect an interim rate rider for the last six months of the year which is equivalent to an annual 6.9% increase over 2001 rates. Revenue has been recognized based on these interim rates. An AEUB ruling on 2002 and 2003 rates is expected in the first half of 2003. The impact of the ruling will be recorded prospectively.

(b) Hourly electrical load

The Company records regulated transmission and distribution revenues based on regulated tariffs approved by the AEUB and the hourly electrical load delivered to end-use customers connected to the Company's distribution system. Commencing on January 1, 2001, hourly electrical load data is determined by the Company through a metering and load settlement function performed by the Company in its role as a distribution system owner.

The methodology used to determine the hourly electrical load by end-use customers is governed by regulation and includes an initial load determination on a monthly basis, used to issue preliminary invoices to the retailers and certain end-use customers. This preliminary load information is then subject to further adjustment by the Company, and a final negotiated settlement of delivered electrical load with applicable retailers and certain end-use customers, which then forms the basis for a final financial settlement of a specific month's delivered electrical load. At this time, the Company is to prepare final invoices to retailers for distribution and transmission services.

At December 31, 2002, due to industry-wide concerns regarding the accuracy and integrity of the load settlement process in general as adopted throughout the Province of Alberta, the Company was unable to reach a final monthly negotiated financial settlement with any of the retailers or end-use customers for any months in 2001 and 2002. Accordingly, the Company has recognized regulated revenue for 2001 and 2002 based on management's best estimate of the hourly electrical load, which will be finalized in the ongoing monthly negotiated final settlement processes. Subsequent adjustments, if any, may be material to these financial statements.

11. EMPLOYEE FUTURE BENEFITS

The Company sponsors a defined contribution plan for the majority of its employees. Certain other long-service employees accrue benefits under a defined benefit pension plan. The Company also provides certain other post-retirement benefits to its retired employees. For regulatory purposes, employee future benefits are recoverable in rates from customers at the time that the Company is required to fund its obligations. Accordingly, expenses for employee future benefits are recognized in these financial statements in accordance with regulatory requirements.

Information with respect to the Company's benefit plans is as follows:

	2002	2001
	$	$
Plan assets	20,777	25,319
Accrued benefit obligation	(10,835)	(11,218)
Plan surplus	9,942	14,101

As ordered by the AEUB, the Company is required to use the plan surplus to fund current and future pension and other post-retirement obligations.

12. RELATED PARTY TRANSACTIONS

In the normal course of business, the Company transacts with its parent and other related companies under common control. The following transactions were measured at the exchange amount:

	2002	2001
	$	$
Included in contracted services are the following amounts charged from related parties:		
Executive management services	2,800	5,022
Information technology costs	19,565	15,977
Aquila direct charges	1,870	2,275
Included in property, plant and equipment:		
Capital project costs	12,197	17,039
Included in accounts receivable	15,413	5,036
Included in accounts payable	19,439	10,195

Except as disclosed elsewhere in these financial statements, the amounts due to and from the Company's parent and other related companies under common control are non-interest bearing, unsecured and due on demand.

13. PROVISION FOR INCOME TAXES

The provision for income taxes varies from the amount that would be expected if computed by applying the enacted Canadian federal and provincial statutory income tax rates to the income before income taxes as shown in the following table:

	2002		2001	
	$	%	$	%
Income before income taxes	60,917	—	37,390	—
Expected provision for income taxes	23,940	39.3	15,741	42.1
Adjustments resulting from differences between income for accounting and income tax purposes related to:				
Capital assets	9,506	15.6	17,026	45.5
Other expenses	(2,439)	(4.0)	(1,893)	(5.0)
Large Corporations Tax	667	1.1	2,439	6.5
Future income taxes — tax rate changes and other	1,702	2.8	(8,071)	(21.6)
Provision for income taxes	33,376	54.8	25,242	67.5

	2002	2001
Comprised of:		
Future income tax provision	(48,941)	17,772
Current income tax provision	82,317	7,470
	33,376	25,242

The net future income tax liability is comprised as follows:

	2002	2001
	$	$
Future income tax asset:		
Regulatory cost deferral included for tax purposes against regulated taxable income	2,962	—
Future income tax liabilities:		
Regulatory cost deferral deducted for tax purposes against regulated taxable income	—	(31,979)
Regulatory cost deferral deducted for tax purposes against non-regulated taxable income	—	(14,000)
	2,962	(45,979)

In connection with ANCA's 2001 negotiated rate settlement with the AEUB, ANCA included a revenue requirement for current income taxes, notwithstanding that the Company's 2001 current income tax liability was reduced through the application of non-capital loss carryforwards, created as a result of the Company's deduction of its regulatory cost deferral in 2000. However, consistent with its negotiated rate settlement, the Company's revenues for the year ended December 31, 2001 included a component for income taxes, which has been reflected as a corresponding charge to future income tax expense.

As described in Note 2, the Company follows the taxes payable method of accounting for income taxes. Had the company accounted for its regulated operations using the liability method, the Company would have additional future income tax liabilities of approximately $60 million at December 31, 2002 ($38 million — 2001).

14. CONTINGENCIES AND COMMITMENTS

(a) Operating lease obligations

The Company has contractual obligations in the normal course of business and operating leases for facilities, office premises and equipment. Future minimum annual lease payments, excluding estimated operating costs, are as follows:

	$
2003	2,999
2004	2,787
2005	2,651
2006	2,620
2007	2,537

(b) TAU operating agreements

The Company and TAU have entered into a number of service agreements to ensure operational efficiencies are maintained through coordinated operations. The agreements have minimum expiry terms of twenty years and are subject to extension based on mutually agreeable terms. Costs, net of related revenues, are estimated to be approximately $3.4 million per year.

(c) Legal proceedings

The Company is subject to various legal proceedings and claims that arise in the ordinary course of business operations. The Company believes that the amount of liability, if any, would not have a material effect on the Company's financial position or results of operations.

(d) Capital expenditures

As an electric utility, the Company is obligated to provide service to customers within its service territory. The Company has forecast capital expenditures for 2003 of $120.7 million, which are largely driven by customer requests or are specifically identified large capital projects. The Company will be required to raise additional capital during 2003 to fund its capital expenditures.

15. CREDIT RISK MANAGEMENT

Substantially all of the customer accounts receivable relate to electricity retailers located in the Province of Alberta. One customer comprised 63% of accounts receivable as at December 31, 2002 (57% at December 31, 2001). The Company has obtained a parental guarantee from this customer. Credit risk is mitigated as the Company would apply to recover any bad debt realized on any retailer's account in future rates.

16. FINANCIAL INSTRUMENTS

The Company's financial instruments consist primarily of accounts receivable, accounts payable, notes payable and short-term debt, debt and other obligations. These financial instruments, except for the note payable to Aquila Networks Canada Finance Limited Partnership, have a fair value that approximates their respective carrying values. As at December 31, 2002, the fair market value of this instrument exceeded the book value by $26.2 million. Fair values for debt are determined using discounted cash flow analysis based on an estimate of the Company's current borrowing rate for each instrument.

Aquila Networks Canada (Alberta) Ltd.

Unaudited Interim Financial Statements
for the six month period ended June 30, 2003

AQUILA NETWORKS CANADA (ALBERTA) LTD.

BALANCE SHEET

(All dollar amounts are in thousands)

	June 30, 2003	December 31, 2002
	Unaudited $	Audited $
ASSETS		
PROPERTY, PLANT AND EQUIPMENT, net of accumulated amortization	554,152	505,927
Regulatory tax basis adjustment, net of accumulated amortization	(113,993)	(116,766)
	440,159	389,161
REGULATORY COST DEFERRAL	—	12,882
GOODWILL, net of accumulated amortization (Note 4)	189,309	269,309
FUTURE INCOME TAX	2,962	2,962
CURRENT ASSETS		
Cash	12,034	—
Accounts receivable (Note 3)	49,414	43,506
Current portion of regulatory cost deferral	69,492	116,664
Supplies	10,624	10,709
Prepaid expenses	198	—
Income taxes receivable	4,721	—
Regulatory deferred charges	4,208	1,996
	150,691	172,875
	783,121	847,189
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
SHAREHOLDER'S EQUITY		
Share capital	347,579	347,579
Deficit	(109,482)	(43,279)
Total shareholder's equity	238,097	304,300
DEBT	230,000	230,000
	468,097	534,300
LIABILITIES		
SECURITIZATION FINANCING	—	25,346
CONTINGENCIES (Note 6)		
REGULATORY COST DEFERRAL	950	—
CURRENT LIABILITIES		
Accounts payable	56,950	61,245
Revenue subject to refund (Note 3)	58,069	—
Notes payable	10,000	6,940
Current portion of securitization financing	99,196	144,477
Short term syndicated loan (Note 5)	89,859	—
Income taxes payable	—	74,881
	314,074	287,543
	783,121	847,189

Approved on behalf of the Board.

The accompanying notes are an integral part of these financial statements.

AQUILA NETWORKS CANADA (ALBERTA) LTD.

STATEMENT OF OPERATIONS
For the six months ended June 30
(All dollar amounts are in thousands)

	2003 Unaudited $	2002 Unaudited $
REVENUES		
Electric rate revenue (Note 3)	68,327	125,340
Other	1,746	3,799
	70,073	129,139
EXPENSES		
Depreciation and amortization (Note 3)	4,222	40,676
Goodwill impairment (Note 4)	80,000	—
Operating labour	22,025	19,794
Contracted services	10,882	13,512
General operating expenses	8,595	11,546
Taxes other than income taxes	3,779	3,664
Regulatory deferred charges	—	(9,007)
	129,503	80,185
EARNINGS (LOSS) FROM OPERATIONS	(59,430)	48,954
INTEREST EXPENSE	12,235	14,133
INCOME (LOSS) BEFORE INCOME TAXES	(71,665)	34,821
INCOME TAXES (RECOVERY)	(5,462)	18,260
NET EARNINGS (LOSS)	(66,203)	16,561

CONSOLIDATED STATEMENT OF DEFICIT
For the six months ended June 30
(All dollar amounts are in thousands)

	2003 Unaudited $	2002 Unaudited $
DEFICIT, BEGINNING OF PERIOD	(43,279)	(70,550)
Net earnings (loss)	(66,203)	16,561
DEFICIT, END OF PERIOD	(109,482)	(53,989)

The accompanying notes are an integral part of these financial statements.

AQUILA NETWORKS CANADA (ALBERTA) LTD.

STATEMENT OF CASH FLOWS
For the six months ended June 30
(All dollar amounts are in thousands)

	2003	2002
	Unaudited $	Unaudited $
OPERATING ACTIVITIES		
Net earnings (loss)	(66,203)	16,561
Add items not involving cash		
Depreciation and amortization	4,222	40,676
Goodwill impairment (Note 4)	80,000	—
Amortization of deferred charges	237	264
Future income taxes	—	(23,112)
Collection of regulatory cost deferral	61,004	69,412
	79,260	103,801
Change in non-cash working capital related to operating activities	(39,950)	32,787
	39,310	136,588
INVESTING ACTIVITIES		
Additions to property, plant and equipment	(49,119)	(41,267)
Additions to deferred charges	(449)	(3,394)
Purchase price adjustments	—	1,795
	(49,568)	(42,866)
FINANCING ACTIVITIES		
Proceeds of note payable to Aquila Networks Canada Finance Limited Partnership	10,000	—
Repayment of note payable	(6,940)	—
Repayments of securitization financing	(70,627)	—
Proceeds of short term syndicated loan (Note 5)	89,859	—
Proceeds of commercial paper	—	9,024
Repayment of other obligations	—	(38,992)
Repayment of debt	—	(48,200)
Redemption of common shares, net of issuances	—	(15,000)
	22,292	(93,168)
INCREASE IN CASH AND CASH EQUIVALENTS	12,034	554
CASH AND CASH EQUIVALENTS, beginning of period	—	—
CASH AND CASH EQUIVALENTS, end of period	12,034	554

The accompanying notes are an integral part of these financial statements.

AQUILA NETWORKS CANADA (ALBERTA) LTD.

NOTES TO FINANCIAL STATEMENTS
For the six months ended June 30, 2003 and 2002
(All tabular dollar amounts are in thousands, unless otherwise noted)

1. BASIS OF PRESENTATION

These unaudited interim financial statements have been prepared in accordance with Canadian generally accepted accounting principles for interim financial statements and do not include all of the disclosures normally found in the audited annual financial statements for Aquila Networks Canada (Alberta) Ltd. (''ANCA'' or the ''Company''). These interim financial statements should be read in conjunction with the Company's audited financial statements for the year ended December 31, 2002.

These financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent audited financial statements. The Company is regulated by the Alberta Energy and Utilities Board (''AEUB''). The AEUB administers acts and regulations covering such matters as tariffs, rates, construction, operations, financing and accounting. The timing of ANCA's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian generally accepted accounting principles for entities not subject to rate regulation.

2. USE OF ESTIMATES

The financial statements have been prepared based on six months of operations ended June 30, 2003. The regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, is determined pursuant to subsequent regulatory decisions or other regulatory proceedings. Due to the inherent uncertainty in making such estimates, actual results reported in future periods could differ materially from those estimated. See also Note 3 for specific commentary regarding revenue estimates.

Interim results will fluctuate due to seasonal demands for electricity and the timing and recognition of regulatory decisions. Consequently, interim results are not necessarily indicative of annual results.

3. REVENUE MEASUREMENT

(a) Regulated rates

As described in Note 10a of the December 31, 2002 audited financial statements, the Company has been operating on interim distribution rates for 2002 and 2003. In February 2003, the AEUB issued its proposed Decision, the effects of which were reflected in the Company's refiled rate application dated March 28, 2003. On July 4, 2003, the AEUB issued a Decision which established distribution tariff rates for 2002 and 2003. While the Decision is subject to an appeal process ending in the fourth quarter of 2003, the Company has reflected the effects of this Decision in these financial statements.

The effects of the Decision have been recognized in the 2003 amounts as follows:

	Relating to 2002	Relating to 2003	Total
Reduction in revenue	$(40,000)	$(18,600)	$(58,600)
Reduction in depreciation	20,400	12,480	32,880
Reduction in income taxes	15,500	6,120	21,620

The total refund to customers has been accrued in the financial statements as at June 30, 2003. As directed by the AEUB, the refund to customers will be made via revised electricity rates applied to electric load consumed during the period August 1 to December 31, 2003.

Included in electric rate revenue in 2003 is $5.8 million (2002 — $nil) related to Option ''B'' revenue collected in 2002, but not recognized until regulatory certainty was attained as a result of the AEUB decision on 2002 and 2003 tariff rates.

(b) Hourly electrical load

As described in Note 10b of the December 31, 2002 audited financial statements, the Company continues to recognize regulated revenue for 2001, 2002 and 2003 based on management's best estimate of the hourly electrical load. The Company is continuing its efforts to reach a final negotiated settlement with its retailers or end-use customers for the electrical load delivered in each of the months from January 2001 to May 2002 inclusive. One retailer has filed a statement of claim which is related, in part, to the settlement of electrical load as described herein (see note 6). Any adjustments will be recorded once signed acceptance is obtained from participants involved in negotiation and these adjustments may be material to these financial statements.

Subsequent to June 30, 2003 and consistent with a process prescribed by the AEUB, the Company has begun to settle monthly electrical load amounts with its retailers and end-user customers for each month beginning June 2002 to present. As at the date of these financial statements, settlements have been reached for the electrical load delivered in the months of June, July and August 2002. These settlements resulted in a net reduction in revenue of $0.9 million, recognized subsequent to June 2003, compared to the revenue amount originally recorded for those months. These settlement amounts are being recorded on a cash basis as settlement is reached each month. Future adjustments, if any, may be material to these financial statements.

4. GOODWILL

The Company's goodwill was written down by $80 million in March 2003. The impairment charge was a result of the AEUB decision on 2002 and 2003 distribution tariff rates, which directed ANCA to decrease depreciation rates creating a reduction in ANCA's annual cash flow (see Note 3a).

5. SUBSEQUENT EVENTS

On July 31, 2003, ANCA received proceeds of a USD$100 million, 364 day unsecured debt facility from a U.S. lender, which is made available by alternate base rate loans (ABR's) or LIBOR loans. The proceeds were used to repay the Company's $112.5 million short term syndicated loan facility that expired on July 31st, and its unsecured revolving demand facility of $25 million. The new facility bears interest at a variable rate based on prime, Federal funds rate or LIBOR rate, with a minimum rate of 6.75% plus the cost related to withholding tax. Placement fees of $2.9 million were incurred and will be expensed over the term of the loan.

On August 1, 2003, ANCA entered into a forward contract to manage foreign exchange exposure on a total of USD$215 million of debt. A portion of this hedge is assigned to Aquila Networks Canada Corp., an affiliated company, to cover its USD$115 million of debt. The forward contract matures on May 31, 2004 and obligates ANCA to buy USD$215 million at an exchange rate of 1.4209.

6. LEGAL STATEMENT OF CLAIM

In a statement of claim filed on August 18, 2003 in the Court of the Queen's Bench of Alberta, EPCOR Energy Services (Alberta) Inc. is pursuing damages of $83 million for alleged breaches of (i) contract, (ii) common law duties and (iii) distribution tariff terms and conditions of service, relating to the provision of the Regulated Rate Option to customers. The Company has not to date made a definitive assessment of potential liability with respect to this claim, however management believes that these allegations are without merit. The outcome is not determinable and accordingly no amount has been accrued for this claim in these financial statements.

UtiliCorp Networks Canada (British Columbia) Ltd.

(formerly West Kootenay Power Ltd.)

Consolidated Financial Statements
December 31, 2001 and 2000

Together with Auditors' Report

The attached consolidated financial statements were audited and reported on by Arthur Andersen LLP (''Arthur Andersen''). Fortis Inc. (the ''Corporation'') has not obtained the consent of Arthur Andersen to the use of its audit report in respect of these financial statements. Arthur Andersen's consent was not obtained because on June 3, 2002, Arthur Andersen ceased to practice public accounting. Because Arthur Andersen has not provided this consent, purchasers of subscription receipts of the Corporation pursuant to the preliminary short form prospectus to which these financial statements are annexed will not have the statutory right of action for damages against Arthur Andersen as prescribed by applicable securities legislation with respect to these financial statements. In addition, Arthur Andersen may not have sufficient assets available to satisfy any judgments against it.

AUDITORS' REPORT

To the Shareholder of
UtiliCorp Networks Canada (British Columbia) Ltd.:

We have audited the consolidated balance sheets of **UTILICORP NETWORKS CANADA (BRITISH COLUMBIA) LTD.** (formerly West Kootenay Power Ltd.) (a British Columbia company) as at December 31, 2001 and 2000 and the consolidated statements of earnings, retained earnings 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, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles, as described in Note 2. As required by the British Columbia Company Act, we report that, in our opinion, these principles have been applied on a consistent basis.

Calgary, Canada
January 23, 2002, except for Note 5(i)
which is as of February 1, 2002.

(Signed) *ARTHUR ANDERSEN LLP*
Chartered Accountants

UTILICORP NETWORKS CANADA (BRITISH COLUMBIA) LTD.
(formerly West Kootenay Power Ltd.)

CONSOLIDATED BALANCE SHEETS
Years ended December 31, 2001 and 2000
(All dollar amounts are in thousands unless otherwise noted)

	2001	2000
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Note 3)	$359,924	$326,049
DEFERRED CHARGES AND OTHER ASSETS (Note 4)	15,689	14,870
CURRENT ASSETS		
Cash	—	473
Accounts receivable (Note 9)	24,490	17,388
Unbilled revenue	6,394	7,396
Inventory	682	564
Prepaid Expenses	1,267	529
	32,833	26,350
TOTAL ASSETS	$408,446	$367,269
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION (Note 5)		
SHAREHOLDER'S EQUITY		
Shareholder's equity		
Common shares	$ 61,500	$ 41,500
Retained earnings	96,706	86,773
Total shareholder's equity	158,206	128,273
DEBT	176,090	177,238
TOTAL CAPITALIZATION	334,296	305,511
LIABILITIES		
FUTURE INCOME TAXES	6,287	7,801
COMMITMENTS AND CONTINGENCIES (Notes 2 and 8)		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities (Note 9)	25,108	13,982
Current portion of debt (Note 5)	37,438	35,602
Accrued interest	3,239	2,789
Income taxes payable	2,078	1,584
	67,863	53,957
TOTAL CAPITALIZATION AND LIABILITIES	$408,446	$367,269

Approved on behalf of the Board:

(Signed) *Don Bacon*, Director

(Signed) *V. Roy Phillips*, Director

The accompanying notes are an integral part of these consolidated statements.

UTILICORP NETWORKS CANADA (BRITISH COLUMBIA) LTD.
(formerly West Kootenay Power Ltd.)

CONSOLIDATED STATEMENTS OF EARNINGS
Years ended December 31, 2001 and 2000
(All dollar amounts are in thousands unless otherwise noted)

	2001	2000
REVENUE		
Sale of power	$143,332	$134,765
Other	4,585	4,117
	147,917	138,882
EXPENSES		
Power purchases	51,051	47,659
Operating and maintenance (Note 9)	26,390	26,235
Amortization	9,843	9,874
Property and B.C. capital taxes	10,342	9,918
Water fees	7,327	7,316
Wheeling	4,334	3,601
	109,287	104,603
EARNINGS FROM OPERATIONS	38,630	34,279
INTEREST EXPENSE		
Secured debentures (Note 5)	8,858	8,934
Other debt (Note 5)	6,333	6,135
	15,191	15,069
EARNINGS BEFORE INCOME TAXES	23,439	19,210
INCOME TAXES (Note 7)	6,692	6,715
NET EARNINGS	$ 16,747	$ 12,495

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS
Years ended December 31, 2001 and 2000

	2001	2000
RETAINED EARNINGS, BEGINNING OF YEAR	$ 86,773	$ 81,084
Net earnings	16,747	12,495
Dividends	6,814	6,806
RETAINED EARNINGS, END OF YEAR	$ 96,706	$ 86,773

The accompanying notes are an integral part of these consolidated statements.

UTILICORP NETWORKS CANADA (BRITISH COLUMBIA) LTD.
(formerly West Kootenay Power Ltd.)

CONSOLIDATED STATEMENTS OF CASH FLOWS
Years ended December 31, 2001 and 2000
(All dollar amounts are in thousands unless otherwise noted)

	2001	2000
OPERATING ACTIVITIES		
Net earnings	$ 16,747	$ 12,495
Add items not involving cash		
Change in non-cash working capital	5,114	(14,246)
Amortization	9,843	9,874
Future income taxes	(1,514)	(278)
	30,190	7,845
INVESTING ACTIVITIES		
Property, plant and equipment	(41,464)	(36,453)
Deferred charges and other non-current assets	(3,073)	(650)
	(44,537)	(37,103)
FINANCING ACTIVITIES		
Common shares issued	20,000	—
Promissory notes payable	—	(15,000)
Term bank loans and demand loan issued	1,800	52,090
Debentures and mortgage repaid	(1,112)	(1,080)
Dividends	(6,814)	(6,806)
	13,874	29,204
DECREASE IN CASH	(473)	(54)
CASH, OPENING BALANCE	473	527
CASH, CLOSING BALANCE	$ —	$ 473
SUPPLEMENTAL DISCLOSURE		
INTEREST PAID	$ 15,587	$ 14,184
INCOME TAXES PAID	$ 7,712	$ 4,943

The accompanying notes are an integral part of these consolidated statements.

UTILICORP NETWORKS CANADA (BRITISH COLUMBIA) LTD.
(formerly West Kootenay Power Ltd.)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2001 and 2002
(All dollar amounts are in thousands unless otherwise noted)

1. ENTITY DEFINITION AND NATURE OF OPERATIONS

UtiliCorp Networks Canada (British Columbia) Ltd. (''UNCBC'' or the ''Company'') (formerly West Kootenay Power Ltd.) was incorporated by an Act of the Legislature of British Columbia. On September 2, 1987 it became a wholly-owned subsidiary of UtiliCorp British Columbia Ltd. (''UCBC'') which ultimately is a wholly-owned subsidiary of UtiliCorp United Inc. (''UCU''), a U.S. public company.

On October 22, 2001 the Company changed its name to UtiliCorp Networks Canada (British Columbia) Ltd.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, Walden Power Partnership (''WPP''), ESI-Power Walden Corporation Ltd. and West Kootenay Power Ltd. (formerly 413569 British Columbia Ltd). All significant inter-company transactions and balances have been eliminated upon consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation

The Company is regulated by the British Columbia Utilities Commission (''BCUC''). The BCUC administers acts and regulations, pursuant to the Utilities Commission Act, covering such matters as tariffs, rates, construction, operations, financing and accounting. The timing of UNCBC's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian generally accepted accounting principles for entities not subject to rate regulation.

Use of estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions 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 period. Certain estimates are necessary since the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, is determined pursuant to subsequent regulatory decisions or other regulatory proceedings. Due to the inherent uncertainty in making such estimates, actual results reported in future periods could differ materially from those estimated.

Revenue recognition

Revenues are recognized as customers are invoiced on a billing cycle basis. In addition, the Company accrues for unbilled revenue for power consumed by customers before year-end which is not yet billed in order to recognize revenue as determined by the BCUC.

Property, plant and equipment

Property, plant and equipment are recorded at cost including an allowance for funds used during construction. The cost of amortizable assets retired together with removal costs less salvage value is charged to accumulated amortization. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

The Company provides for amortization on a straight-line basis calculated on the investment in amortizable assets in service at the beginning of the year. Rates are designed to amortize the cost of the assets over their estimated service life that on average approximates 46 years. The application of these rates for the year ended December 31, 2001 results in a composite rate of 2.2% (2.1% — 2000).

Beginning in 2000, the BCUC has instructed the Company to utilize a rate stabilization mechanism to ensure annual customer rate increases do not exceed 5%. The BCUC has directed the Company to adjust the prior years' amortization rate of its transmission assets from an average of 35 years to a rate of 50 years on a prospective basis for rate making purposes. The rate stabilization is recorded as a charge to accumulated amortization of Plant and Equipment in the year only to the extent required. A total rate stabilization account of $32.9 million is available to be used in years beginning in 2000 but is not recorded until utilized.

During 2001, the amortization expense has been reduced by $3.1 million ($nil — 2000) of rate stabilization, as approved by the BCUC.

Customers' portion of costs

Certain additions to property, plant and equipment are made with the assistance of non-refundable contributions from customers and others when the estimated revenue is less than the cost of providing service or when special equipment is needed to supply the customers' specific requirements. Such amounts are recorded as a reduction of property, plant and equipment and are being amortized over the estimated service lives of the related assets by an offset against the provision for amortization.

Deferred charges and other assets

Certain revenues and costs are carried on the consolidated balance sheets and are amortized against earnings as ordered or agreed to by the BCUC. Other deferred costs are carried on the consolidated balance sheets and are amortized against earnings over the expected period of benefit. During the year, amortization of $2.0 million ($1.3 million — 2000) was charged against operations.

Income taxes

The Company follows the taxes payable method of accounting for income taxes on certain regulated earnings as ordered by the BCUC. For non-regulated business, income tax assets and income tax liabilities are recognized, at substantially enacted rates, for differences between the amounts reported for financial statement purposes and their respective tax basis. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income in the period that the rate change occurs.

Employee benefits and post-retirement benefits

The Company and its subsidiaries have a number of defined benefit plans providing pensions to most of its employees. These plans are accounted for using the method recommended by Section 3461 of the CICA Handbook. The Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. The Company has adopted the following policy:

Defined pension benefit

For the purpose of calculating the expected return on plan assets, those assets are valued at fair value. The cost of these pensions is determined by independent actuaries using the projected benefit method prorated on service and management's best estimates of expected plan investment performance, salary escalation, and retirement ages of employees.

Adjustments arising from plan amendments, changes in assumptions and the excess of net actuarial gains or losses over 10% of the greater of the benefit obligation and the fair value of the plan assets are amortized on a straight line basis over the expected average remaining service life of the employees covered by the plans. The average remaining service life of the employees covered by these plans ranges from 13 to 15 years.

Post-retirement benefits

As ordered by the BCUC, the Company accounts for post-retirement benefits as employer contributions are paid.

Prior year amounts

Certain prior year amounts have been reclassified to conform with current year presentation.

3. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	Net Book Value 2001	Net Book Value 2000
Generation	$102,254	$ 17,831	$ 84,423	$ 78,090
Substations	90,606	31,577	59,029	55,503
Transmission	85,852	17,481	68,371	56,759
Distribution	152,783	52,151	100,632	90,441
General	68,674	21,205	47,469	45,256
Total	$500,169	$140,245	$359,924	$326,049

4. DEFERRED CHARGES AND OTHER ASSETS

	Net Value 2001	Net Value 2000
Energy management costs	$ 5,296	$ 5,854
Energy management loans	1,810	187
Prepaid pension costs	6,611	5,818
Other	1,249	1,737
Debt issue costs	993	1,085
Incentive sharing adjustment	(270)	189
	$15,689	$14,870

5. CAPITALIZATION

(i) SHARE CAPITAL

AUTHORIZED
500,000,000 (750,000 — 2000) Common shares, with a par value of $100 each
500,000,000 (2,000,000 — 2000) Preferred shares, with a par value of $25 each, issuable in series

	2001	2000
ISSUED		
615,000 (415,000 — 2000) Common shares	$61,500	$41,500

Subsequent to year end, the Company issued 150,000 common shares for cash consideration of $15 million.

(ii) DEBT

	2001	2000
Secured		
Series E 11% due December 1, 2009	$ 9,000	$ 9,750
Series F 9.65% due October 16, 2012	15,000	15,000
Series G 8.8% due August 28, 2023	25,000	25,000
Series H 8.77% due February 1, 2016	25,000	25,000
Series I 7.81% due December 1, 2021	25,000	25,000
WPP mortgage 9.44% due October 31, 2013	8,238	8,600
	107,238	108,350
Promissory note payable	50,000	50,000
Term bank loans and demand loan, interest at prime	56,290	54,490
	213,528	212,840
Current portion of debt	(37,438)	(35,602)
	$176,090	$177,238

The secured debentures are collateralized by a fixed and floating first charge on the assets of the Company and are guaranteed by UCU. The trust deed provides for sinking fund payments of $750,000 per year for Series E debentures.

The promissory note payable to UtiliCorp Canada Finance Limited Partnership (''UCFLP''), an entity under common control, is unsecured, bears interest at 8.66% (6.95% — 2000) and is due June 15, 2011. During the year, the Company recorded interest expense of $3.9 million on the UCFLP promissory note.

The term bank and demand loans are unsecured, guaranteed by UCU, and drawn under line of credit facilities which provide for maximum borrowings of $60 million. A total of $40 million of these facilities are repayable on demand of which $36.3 million was outstanding at December 31, 2001. The remaining portion of $20 million is due May 30, 2007.

As at December 31, 2001 the fair market value of the debt exceeded the book value by $13.1 million ($7.8 million — 2000).

Principal payments required within the next five years and thereafter are as follows:

	Sinking Fund Requirement	Demand Loan and Maturing Issues of Debt
2002	750	36,688
2003	750	436
2004	750	480
2005	750	527
2006	750	579
Thereafter	2,250	168,818

6. PENSIONS AND OTHER POST RETIREMENT BENEFITS

The Company has several defined benefit pension plans, which cover most employees. Pension plan assets at December 31, 2001 had a market value of $58.5 million ($62.8 million — 2000). The value of accrued pension benefits, based on an independent valuation of the plans using management's best estimate of assumptions, was $66.7 million ($65.7 million — 2000) at December 31, 2001 including an allowance for the effect of future pay increases, where applicable. Experience gains and losses and amounts arising as a result of changes in assumptions and plan amendments are deferred and amortized to operations over the expected average remaining service life of the employee groups.

The expense for the Company's pension benefits is as follows:

	2001	2000
Employer current service cost	$ 941	$ 1,305
Interest cost	4,389	4,323
Expected return on plan assets	(4,776)	(4,161)
Amortization:		
Net transition obligations	976	1,020
Prior service cost	123	56
Total net benefit plan expense	$ 1,653	$ 2,543

Information about the Company's defined benefit plans is as follows:

	2001	2000
Accrued benefit obligation —		
Balance, beginning of year	$ 65,749	$ 60,951
Current service cost	2,298	2,596
Interest cost	4,389	4,323
Benefits paid	(4,288)	(3,260)
Prior service cost	2,002	—
Actuarial losses (gains)	(1,303)	1,139
Transfers	(2,187)	—
Balance, end of year	$ 66,660	$ 65,749
Plan assets —		
Balance, beginning of year	$ 62,847	$ 51,412
Actual return on plan assets	(1,560)	10,230
Employer contributions	2,216	3,174
Member contributions	1,412	1,291
Benefits paid	(4,288)	(3,260)
Transfers	(2,114)	—
Fair value, end of year	$ 58,513	$ 62,847
Funded status	$ (8,147)	$ (2,902)
Contributions receivable	1,635	1,446
Unamortized net actuarial gain	(710)	(6,158)
Unamortized transitional obligation	10,869	12,349
Unamortized prior service cost	2,964	1,083
Accrued benefit asset	$ 6,611	$ 5,818

Included in the above accrued benefit obligation and fair value of plan assets at year-end are the following amounts in respect of plans that are not fully funded:

	2001	2000
Accrued benefit obligation	$36,119	$32,822
Fair value of plan assets	27,869	26,823
Funded status — plan deficit	$ 8,250	$ 5,999

The significant actuarial assumptions, adopted in measuring the Company's accrued benefit obligations, are as follows:

	2001	2000
Discount rate	7.0%	7.0%
Expected long-term rate of return on plan assets	8.0%	8.0%
Rate of compensation increase	3.5%	3.5%
Estimated remaining service life	13.5 years	13.6 years

7. INCOME TAXES

The provision for income taxes varies from the amount that would be expected if computed by applying the Canadian federal and provincial statutory income tax rates to the earnings before income taxes as shown in the following table:

	2001		2000	
		%		%
Earnings before income taxes	$23,439		$19,210	
Expected provision for income taxes	$10,271	43.8	$ 8,668	45.1
Adjustments in income taxes resulting from items capitalized for accounting but expensed for income tax purposes —				
Operating expenses	(1,074)	(4.6)	(1,120)	(5.8)
Allowance for funds used during construction	(371)	(1.6)	(266)	(1.4)
Other temporary differences	(1,644)	(7.0)	(811)	(4.2)
Large Corporation Tax	775	3.3	615	3.2
Changes in income tax rates	(1,500)	(6.4)	—	—
Other	235	1.0	(371)	(1.9)
Income tax expense	$ 6,692	28.5	$ 6,715	35.0

The future income tax liability is comprised as following:

	2001	2000
Net book value of non-regulated plant and equipment in excess of tax basis	$6,287	$7,801

8. COMMITMENTS

(i) *Capital Projects*

Capital utility expenditures for 2002 are planned to total approximately $89.6 million consisting of $67.6 million for transmission system upgrading, $5.1 million for generation system upgrading, $1.9 million for customer extensions and upgrading, and $15.0 million for other utility plant.

(ii) *Brilliant Power Purchase Contract*

On May 3, 1996 an Order was granted by the BCUC approving a 60-year power purchase contract for the output of the Brilliant hydro-electric plant located near Castlegar, B.C. The Brilliant plant is owned by the Columbia Basin Power Corporation (''CBPC''), a joint venture between the Columbia Power Corporation and the Columbia Basin Trust. The Company operates and maintains the Brilliant plant for the CBPC in return for a management fee.

The contract requires fixed monthly payments based on specified take-or-pay amounts of energy. The contract includes a market related price adjustment after 30 years of the 60-year term. The Company has recorded the contract as an operating lease with minimum payments required over the next five years as follows:

	Amount
2002	$23,972
2003	29,579
2004	31,375
2005	32,721
2006	32,746

(iii) *Firm Power Purchase Contracts*

The Company has a long-term, minimum-payment, firm power purchase contract with B.C. Hydro. The contract includes a take-or-pay provision based on a five-year rolling nomination of capacity requirements. The Company also has a short-term, firm power purchase contract with Aquila Canada Corporation, a company under common control, covering 50 to 100 MW at various intervals throughout 2002, with a take-or-pay clause based on specified amounts of energy.

Minimum payments required over the next five years are as follows:

	Amount
2002	$13,869
2003	5,823
2004	5,293
2005	5,293
2006	5,293

(iv) *Office Lease*

Under a sale-leaseback agreement, on September 29, 1993 the Company began leasing its Trail, B.C. office building for a term of 30 years. The terms of the agreement require future minimum aggregate lease payments of $25 million and grant the Company repurchase options at year 20 and year 30 of the lease term. As directed by the BCUC, minimum payments required over the next five years are as follows:

	Amount
2002	$310
2003	310
2004	600
2005	600
2006	600

(v) *Legal Proceedings*

The Company is subject to various legal proceedings and claims that arise in the ordinary course of business operations. The Company believes that the amount of liability, if any, from these actions would not have a material effect on the Company's financial position or results of operations.

9. RELATED PARTY TRANSACTIONS

In addition to transactions and balances disclosed elsewhere, in the normal course of business, the Company transacts with its parent and other related companies under common control. The following transactions were measured at the exchange amount.

At December 31, 2001, the amounts due to and from the Company's parent and other related companies under common control are non-interest bearing, unsecured and due on demand.

	2001	2000
Included in accounts receivable	$7,401	$1,518
Included in accounts payable	$4,534	$1,839

Other related transactions included in power purchase expense is the sale of excess power to Aquila Canada Corp. for $6.1 million ($nil — 2000). Included in operating and maintenance expenses are executive and management services from UtiliCorp Networks Canada Ltd. of $1.7 million ($nil — 2000). Costs of $0.3 million ($0.2 million — 2000) were charged to the Company by UCU for services obtained as requested and are included in operating and maintenance expenses.

10. FINANCIAL INSTRUMENTS

The Company uses forward foreign currency contracts to reduce its exposure to fluctuations in the U.S. dollar to Canadian dollar exchange rates. The contracts are normally for terms of up to twelve months and are used as hedges of the Company's net U.S. dollar denominated power purchase contracts. Gains and losses arising on these financial instruments are offset against the gains and losses arising on the maturity of the underlying transactions.

At December 31, 2001, the Company has forward foreign currency contracts to sell U.S.$1.6 million between January 22, 2002 and March 20, 2002 at rates between $0.6327 and $0.6326. Had these contracts been settled on December 31, 2001, an additional profit of $20 thousand would have been recognized.

The Company's other financial instruments consist primarily of accounts receivable, unbilled revenue, accounts payable and accrued liabilities, and debt. These financial instruments have a fair value, which approximates carrying value, unless otherwise disclosed.

Aquila Networks Canada (British Columbia) Ltd.

Formerly UtiliCorp Networks Canada (British Columbia) Ltd.

Consolidated Financial Statements
December 31, 2002 and 2001

Together with Auditors' Report

AUDITORS' REPORT

To the Directors of

Aquila Networks Canada (British Columbia) Ltd.:

We have audited the consolidated balance sheet of **AQUILA NETWORKS CANADA (BRITISH COLUMBIA) LTD.** as at December 31, 2002 and the consolidated statements of earnings, retained earnings and cash flows for the year 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 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 consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles. As required by the British Columbia Company Act, we report that, in our opinion, these principles have been applied on a consistent basis.

The consolidated financial statements as at December 31, 2001 and for the year then ended were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those financial statements in their report dated January 23, 2002 (except for Note 5(i) which was dated as of February 1, 2002).

Calgary, Canada	(Signed) *KPMG LLP*
February 19, 2003	Chartered Accountants

Aquila Networks Canada (British Columbia) Ltd.

CONSOLIDATED BALANCE SHEETS
As at December 31

(All dollar amounts are in thousands)

	2002	2001
	$	$
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Note 3)	416,015	359,924
DEFERRED CHARGES AND OTHER ASSETS (Note 4)	13,024	15,689
CURRENT ASSETS		
Cash	41	—
Accounts receivable (Note 9)	14,795	24,490
Unbilled revenue	12,882	6,394
Income taxes receivable	3,685	—
Inventory	428	682
Prepaid expenses	688	1,267
	32,519	32,833
	461,558	408,446
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION (Note 5)		
SHAREHOLDER'S EQUITY		
Common shares	76,500	61,500
Retained earnings	93,205	96,706
Total shareholder's equity	169,705	158,206
DEBT	224,917	176,090
	394,622	334,296
LIABILITIES		
FUTURE INCOME TAXES (Note 7)	1,807	6,287
COMMITMENTS (Note 8)		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities (Note 9)	39,237	25,108
Current portion of debt (Note 5)	21,962	37,438
Accrued interest	3,930	3,239
Income taxes payable	—	2,078
	65,129	67,863
	461,558	408,446

Approved on behalf of the Board:

(Signed) *V. Roy Phillips*, Director

(Signed) *Fauzia Lalani*, Director

The accompanying notes are an integral part of these consolidated statements.

Aquila Networks Canada (British Columbia) Ltd.

CONSOLIDATED STATEMENTS OF EARNINGS
For the year ended December 31
(All dollar amounts are in thousands)

	2002	2001
	$	$
REVENUE		
Sale of power	149,902	143,332
Other	4,092	4,585
	153,994	147,917
EXPENSES		
Power purchases	52,154	51,051
Operating and maintenance (Note 9)	35,670	26,390
Amortization (Note 10)	24,685	9,843
Property and B.C. capital taxes	9,877	10,342
Water fees	7,270	7,327
Wheeling	4,101	4,334
	133,757	109,287
EARNINGS FROM OPERATIONS	20,237	38,630
INTEREST EXPENSE		
Secured debentures (Note 5)	10,283	8,858
Other debt (Note 5)	6,509	7,179
Allowance for funds used during construction	(2,451)	(846)
	14,341	15,191
EARNINGS BEFORE INCOME TAXES	5,896	23,439
INCOME TAX (RECOVERY) EXPENSE (Notes 7 and 10)	(242)	6,692
NET EARNINGS	6,138	16,747

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS
For the year ended December 31
(All dollar amounts are in thousands)

	2002	2001
	$	$
RETAINED EARNINGS, BEGINNING OF YEAR	96,706	86,773
Net earnings	6,138	16,747
Dividends	9,639	6,814
RETAINED EARNINGS, END OF YEAR	93,205	96,706

The accompanying notes are an integral part of these consolidated statements.

Aquila Networks Canada (British Columbia) Ltd.

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the year ended December 31
(All dollar amounts are in thousands)

	2002	2001
	$	$
OPERATING ACTIVITIES		
Net earnings	6,138	16,747
Add items not involving cash		
Amortization	24,685	9,843
Future income taxes	(4,481)	(1,514)
Change in deferred charges related to operating activities	994	(793)
Change in non-cash working capital	13,098	5,114
	40,434	29,397
INVESTING ACTIVITIES		
Property, plant and equipment	(78,759)	(41,464)
Change in deferred charges related to investing activities	(22)	(2,280)
	(78,781)	(43,744)
FINANCING ACTIVITIES		
Common shares issued	15,000	20,000
Term bank loans and demand loan issued (repaid)	(15,476)	1,800
Debentures issued	50,000	—
Debentures and mortgage repaid	(1,173)	(1,112)
Dividends	(9,639)	(6,814)
Change in deferred charges related to financing activities	(324)	—
	38,388	13,874
INCREASE (DECREASE) IN CASH	41	(473)
CASH, OPENING BALANCE	—	473
CASH, CLOSING BALANCE	41	—
CASH FLOWS INCLUDE THE FOLLOWING ELEMENTS:		
Interest paid	16,249	15,587
Income taxes paid	9,407	7,712

The accompanying notes are an integral part of these consolidated statements.

Aquila Networks Canada (British Columbia) Ltd.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the year ended December 31, 2002 and 2001
(All tabular dollar amounts are in thousands, unless otherwise noted)

1. ENTITY DEFINITION AND NATURE OF OPERATIONS

Aquila Networks Canada (British Columbia) Ltd. (''ANCBC'' or the ''Company'') (formerly UtiliCorp Networks Canada (British Columbia) Ltd.) was incorporated by an Act of the Legislature of British Columbia. On September 2, 1987 it became a wholly-owned subsidiary of Aquila Networks British Columbia Ltd. (''ANBC'') which ultimately is a wholly-owned subsidiary of Aquila, Inc., a U.S. public company.

On May 31, 2002 the Company changed its name to Aquila Networks Canada (British Columbia) Ltd.

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, Walden Power Partnership (''WPP''), ESI-Power Walden Corporation Ltd. and West Kootenay Power Ltd. All significant inter-company transactions and balances have been eliminated upon consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Regulation

The Company is regulated by the British Columbia Utilities Commission (''BCUC''). The BCUC administers acts and regulations, pursuant to the Utilities Commission Act, covering such matters as tariffs, rates, construction, operations, financing and accounting. The timing of ANCBC's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian generally accepted accounting principles for entities not subject to rate regulation.

Use of estimates

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions 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 period. Certain estimates are necessary since the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, is determined pursuant to subsequent regulatory decisions or other regulatory proceedings. Due to the inherent uncertainty in making such estimates, actual results reported in future periods could differ materially from those estimated.

Revenue recognition

Revenues are recognized as customers are invoiced on a billing cycle basis. In addition, the Company accrues for unbilled revenue for power consumed by customers before year-end in order to recognize revenue as determined by the BCUC.

Cash and cash equivalents

Cash and cash equivalents are comprised of highly liquid investments with original maturities of 90 days or less.

Property, plant and equipment

Property, plant and equipment are recorded at cost including an allowance for funds used during construction. The cost of amortizable assets retired together with removal costs less salvage value is charged to accumulated amortization. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

The Company provides for amortization on a straight-line basis calculated on the investment in amortizable assets in service at the beginning of the year. The application of these rates for the year ended December 31, 2002 results in a composite rate of 2.5% (2.2% — 2001).

Beginning in 2000, the BCUC has instructed the Company to utilize a rate stabilization mechanism to ensure annual customer rate increases do not exceed 5%. The BCUC has directed the Company to adjust the amortization rate of its transmission assets from an average of 35 years to a rate of 50 years on a prospective basis for rate making purposes. The rate stabilization is recorded as a charge to accumulated amortization of plant and equipment in the year only to the extent required. A total remaining notional rate stabilization account of $29.8 million is available to be used in future years, but is not recorded until utilized.

During 2002, the amortization expense has been reduced by $nil ($3.1 million — 2001) of rate stabilization, as approved by the BCUC.

Customers' portion of costs

Certain additions to property, plant and equipment are made with the assistance of non-refundable contributions from customers and others when the estimated revenue is less than the cost of providing service or when special equipment is needed to supply the customers' specific requirements. Such amounts are recorded as a reduction of property, plant and equipment and are being amortized over the estimated service lives of the related assets by an offset against the provision for amortization.

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Income taxes

The Company follows the taxes payable method of accounting for income taxes on certain regulated earnings as ordered by the BCUC. For non-regulated business, income tax assets and income tax liabilities are recognized, at substantially enacted rates, for differences between the amounts reported for financial statement purposes and their respective tax bases. The effect of a change in income tax rates on future income tax assets and future income tax liabilities is recognized in income in the period that the rate change occurs.

Employee benefits and post-retirement benefits

The Company and its subsidiaries have a number of defined benefit plans providing pensions to most of their employees. These plans are accounted for using the method recommended by Section 3461 of the CICA Handbook. The Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. The Company has adopted the following policies:

Defined pension benefit

For the purpose of calculating the expected return on plan assets, those assets are valued at fair value. The cost of these pensions is determined by independent actuaries using the projected benefit method prorated on service and management's best estimates of expected plan investment performance, salary escalation, and retirement ages of employees.

Adjustments arising from plan amendments, changes in assumptions and the excess of net actuarial gains or losses over 10% of the greater of the benefit obligation and the fair value of the plan assets are amortized on a straight line basis over the expected average remaining service life of the employees covered by the plans. The average remaining service life of the employees covered by these plans ranges from 13 to 15 years. The Company uses a measurement date of September 30th for all of its plans.

The Company undertook a workforce reorganization during the year. In conjunction with this reorganization, approximately 40% of the active members of one of the Company's pension plans terminated employment. Management considers this workforce reduction to be a curtailment under pension accounting standards, and the curtailment would normally result in a charge to net income in 2002 of $0.9 million. However, approval has been received from the BCUC to continue to record pension expense as if the curtailment did not occur. Accordingly, no expense relating to the curtailment is recorded in these financial statements.

Post-retirement benefits

As ordered by the BCUC, the Company accounts for post-retirement benefits as employer contributions are paid.

3. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	Net Book Value 2002	Net Book Value 2001
Generation	$103,646	$ 30,666	$ 72,980	$ 84,423
Substations	91,589	32,897	58,692	59,029
Transmission	134,151	18,869	115,282	68,371
Distribution	178,145	55,697	122,448	100,632
General	69,189	22,576	46,613	47,469
Total	$576,720	$160,705	$416,015	$359,924

4. DEFERRED CHARGES AND OTHER ASSETS

	2002	2001
Energy management costs, net of tax of $3.1 million (2001 — $3.6 million)	$ 4,909	$ 5,296
Energy management loans	1,213	1,810
Prepaid pension costs	6,775	6,611
Other	539	1,249
Debt issue costs	1,264	993
Incentive sharing adjustment	(1,676)	(270)
	$13,024	$15,689

5. CAPITALIZATION

(i) SHARE CAPITAL

AUTHORIZED
500,000,000 Common shares, with a par value of $100 each
500,000,000 Preferred shares, with a par value of $25 each, issuable in series

	2002	2001
ISSUED		
765,000 Common shares (615,000 — 2001)	$76,500	$61,500

(ii) DEBT

	2002	2001
Secured		
Series E 11% due December 1, 2009	$ 8,250	$ 9,000
Series F 9.65% due October 16, 2012	15,000	15,000
Series G 8.8% due August 28, 2023	25,000	25,000
Series H 8.77% due February 1, 2016	25,000	25,000
Series I 7.81% due December 1, 2021	25,000	25,000
Series J 6.75% due July 31, 2009	50,000	—
WPP mortgage 9.44% due October 31, 2013	7,840	8,238
	156,090	107,238
Promissory note payable	50,000	50,000
Term bank and demand loans	40,789	56,290
	246,879	213,528
Current portion of debt	(21,962)	(37,438)
	$224,917	$176,090

The secured debentures are collateralized by a fixed and floating first charge on the assets of the Company and are guaranteed by Aquila, Inc. The trust deed provides for sinking fund payments of $750,000 per year for Series E debentures.

The promissory note payable to Aquila Networks Canada Finance Limited Partnership (''ANCFLP''), an entity under common control, is unsecured, bears interest at 8.66% and is due June 15, 2011. During the year, the Company recorded interest expense of $4.3 million ($3.9 million — 2001) on the ANCFLP promissory note.

The term bank and demand loans are unsecured and drawn under line of credit facilities which provide for maximum borrowings of $50 million. A total of $30 million of these facilities are repayable on demand of which $20.8 million was outstanding at December 31, 2002. The demand facility bears interest at prime. The remaining outstanding balance of $20 million is due May 29, 2005, is guaranteed by Aquila Inc., and is drawn by way of bankers acceptances.

As at December 31, 2002 the fair market value of the debt exceeded the book value by $24.0 million ($13.1 million — 2001).

Included within interest expense is $13.6 million related to long-term debt.

Principal payments required within the next five years and thereafter are as follows:

	Sinking Fund Requirement	Demand Loan and Maturing Issues of Debt
2003	750	21,212
2004	750	474
2005	750	20,521
2006	750	572
2007	750	629
Thereafter	1,500	198,221

6. PENSIONS AND OTHER POST RETIREMENT BENEFITS

The Company has several defined benefit pension plans, which cover most employees. The expense for the Company's pension benefits is as follows:

	2002	2001
Employer current service cost	$ 965	$ 941
Interest cost	4,674	4,389
Expected return on plan assets	(4,460)	(4,776)
Amortization:		
Net transition obligations	980	976
Prior service cost	252	123
Total net benefit plan expense	$ 2,411	$ 1,653

Information about the Company's defined benefit plans is as follows:

	2002	2001
Accrued benefit obligation-		
Balance, beginning of year	$ 66,660	$65,749
Current service cost	2,273	2,298
Interest cost	4,674	4,389
Benefits paid	(3,506)	(4,288)
Prior service cost	—	2,002
Actuarial losses (gains)	5,086	(1,303)
Transfers	(583)	(2,187)
Balance, end of year	$ 74,604	$66,660
Plan assets-		
Balance, beginning of year	$ 58,513	$62,847
Actual return on plan assets	(371)	(1,560)
Employer contributions	3,498	2,216
Member contributions	1,671	1,412
Benefits paid	(3,506)	(4,288)
Transfers and non-investment expenses	(986)	(2,114)
Fair value, end of year	$ 58,819	$58,513
Funded status	$(15,785)	$ (8,147)
Contributions receivable	239	1,635
Unamortized net actuarial gain	9,720	(710)
Unamortized transitional obligation	9,888	10,869
Unamortized prior service cost	2,713	2,964
Accrued benefit asset	$ 6,775	$ 6,611

Included in the above accrued benefit obligation and fair value of plan assets at year-end are the following amounts in respect of plans that are not fully funded:

	2002	2001
Accrued benefit obligation	$74,604	$36,119
Fair value of plan assets	58,819	27,869
Funded status — plan deficit	$15,785	$ 8,250

The significant actuarial assumptions, adopted in measuring the Company's accrued benefit obligations, are as follows:

	2002	2001
Discount rate	6.5%	7.0%
Expected long-term rate of return on plan assets	7.5%	8.0%
Rate of compensation increase	3.5%	3.5%
Estimated remaining service life	13.5 years	13.5 years

7. INCOME TAXES

The provision for income taxes varies from the amount that would be expected if computed by applying the Canadian federal and provincial statutory income tax rates to the earnings before income taxes as shown in the following table:

	2002		2001	
	$	%	$	%
Earnings before income taxes	5,896	—	23,439	—
Expected provision for income taxes	2,288	38.8	10,271	43.8
Adjustments in income taxes resulting from items capitalized for accounting but expensed for income tax purposes —				
Operating expenses	(844)	(14.3)	(1,074)	(4.6)
Allowance for funds used during construction	(951)	(16.0)	(371)	(1.6)
Other temporary differences	(1,224)	(20.8)	(1,644)	(7.0)
Large Corporation Tax	905	15.3	775	3.3
Changes in income tax rates	—	—	(1,500)	(6.4)
Other	(416)	(7.1)	235	1.0
Income tax (recovery) expense	(242)	(4.1)	6,692	28.5

Income tax (recovery) expense is comprised of:

	2002	2001
Future income tax recovery	$ (4,481)	$ (1,500)
Current income tax expense	4,239	8,192
	$ (242)	$ 6,692

The future income tax liability is comprised as follows:

	2002	2001
Net book value of non-regulated plant and equipment in excess of tax basis	$1,807	$6,287

As described in Note 2, the Company follows the taxes payable method of accounting for income taxes for regulated operations. Had the Company accounted for its regulated operations using the liability method, the Company would have additional future income tax liabilities of approximately $36.5 million at December 31, 2002 ($36.5 million — 2001).

8. COMMITMENTS

(i) *Brilliant Power Purchase Contract*

On May 3, 1996 an Order was granted by the BCUC approving a 60-year power purchase contract for the output of the Brilliant hydro-electric plant located near Castlegar, B.C. The Brilliant plant is owned by the Columbia Basin Power Corporation (''CBPC''), a joint venture between the Columbia Power Corporation and the Columbia Basin Trust. ANCBC operates and maintains the Brilliant plant for the CBPC in return for a management fee.

The contract requires fixed monthly payments based on specified natural flow take-or-pay amounts of energy. The contract includes a market related price adjustment after 30 years of the 60-year term. The Company is accounting for the contract as an operating lease as directed by the BCUC, with minimum payments required over the next five years as follows:

	Amount
2003	$31,682
2004	31,977
2005	32,617
2006	33,269
2007	33,935

(ii) *Firm Power Purchase Contracts*

The Company has a long-term, minimum-payment, firm power purchase contract with B.C. Hydro. The contract includes a take-or-pay provision based on a five-year rolling nomination of capacity requirements.

Minimum payments required over the next five years are as follows:

	Amount
2003	$7,103
2004	5,388
2005	5,496
2006	5,606
2007	5,718

(iii) *Office Lease*

Under a sale-leaseback agreement, on September 29, 1993 the Company began leasing its Trail, B.C. office building for a term of 30 years. The terms of the agreement require future minimum aggregate lease payments of $25 million and grant the Company repurchase options at year 20 and year 30 of the lease term. The Company is accounting for the lease as an operating lease, as directed by the BCUC. Minimum payments required over the next five years are as follows:

	Amount
2003	$310
2004	600
2005	600
2006	600
2007	600

(iv) *Legal Proceedings*

The Company is subject to various legal proceedings and claims that arise in the ordinary course of business operations. The Company believes that the amount of liability, if any, from these actions would not have a material effect on the Company's financial position or results of operations.

(v) *Capital Expenditures*

As an electric utility, the Company is obligated to provide service to customers within its service territory. The Company has forecast capital expenditures of $62.8 million for 2003, which are largely driven by customer requests or are large capital projects specifically approved by the BCUC. The Company will be required to raise additional capital during 2003 to fund its capital expenditures.

9. RELATED PARTY TRANSACTIONS

In addition to transactions and balances disclosed elsewhere, in the normal course of business, the Company transacts with its parent and other related companies under common control. The following transactions were measured at the exchange amount.

At December 31, 2002, the amounts due to and from the Company's parent and other related companies under common control are non-interest bearing, unsecured and due on demand.

	2002	2001
Included in accounts receivable	$ 2,957	$7,401
Included in accounts payable	$16,364	$8,335
Capital project costs included in Property, Plant & Equipment	$ 8,098	$5,007

Included in power purchase expense is the sale of excess power to Aquila Canada Corp. for $0.1 million ($6.1 million — 2001). Included in operating and maintenance expenses are executive and management services from Aquila Networks Canada Ltd. of $1.1 million ($1.7 million — 2001). Costs of $0.3 million ($0.3 million — 2001) were charged to the Company by Aquila, Inc. for services obtained as requested and are included in operating and maintenance expenses.

10. ASSET IMPAIRMENT CHARGE

Included in amortization expense for 2002 is a charge of $10.0 million to reflect an impairment in the carrying value of the Walden power plant (''Walden''). Income tax expense includes a related future income tax recovery of $4.4 million.

11. FINANCIAL INSTRUMENTS

The Company's financial instruments consist primarily of accounts receivable, accounts payable, and debt. These financial instruments, except for debt (Note 5), have a fair value that approximates their respective carrying values. Fair values for debt are determined using discounted cash flow analysis based on an estimate of the Company's current borrowing rate for each instrument.

12. SUBSEQUENT EVENT

In February 2003, the BCUC approved a 4.3% rate increase for 2003 and an extension of the terms of the performance-based regulation regime under which the Company currently operates.

Aquila Networks Canada (British Columbia) Ltd.

Unaudited Interim Financial Statements
June 30, 2003

Aquila Networks Canada (British Columbia) Ltd.

CONSOLIDATED BALANCE SHEET
(All dollar amounts are in thousands)

	June 30, 2003	December 31, 2002
	Unaudited $	Audited $
ASSETS		
PROPERTY, PLANT AND EQUIPMENT (Note 4)	427,715	416,015
DEFERRED CHARGES AND OTHER ASSETS	13,988	13,024
CURRENT ASSETS		
Cash	195	41
Accounts receivable	35,753	14,795
Unbilled revenue	9,408	12,882
Income taxes receivable	2,338	3,685
Inventory	420	428
Prepaid Expenses	4,244	688
	52,358	32,519
	494,061	461,558
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION		
SHAREHOLDER'S EQUITY		
Common shares	76,500	76,500
Retained earnings	102,119	93,205
Total shareholder's equity	178,619	169,705
DEBT	225,340	224,917
TOTAL CAPITALIZATION	403,959	394,622
LIABILITIES		
FUTURE INCOME TAXES	1,765	1,807
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	41,563	39,237
Current debt	42,935	21,962
Accrued interest	3,839	3,930
	88,337	65,129
TOTAL CAPITALIZATION AND LIABILITIES	494,061	461,558

Approved on behalf of the Board:

(Signed) *Fauzia Lalani*	(Signed) *James M. Greene*
Director	Director

Aquila Networks Canada (British Columbia) Ltd.

CONSOLIDATED STATEMENTS OF EARNINGS

(All dollar amounts are in thousands)

	3 months ended June 30		6 months ended June 30	
	2003	2002	2003	2002
	Unaudited $	Unaudited $	Unaudited $	Unaudited $
REVENUE				
Sale of power	36,165	35,035	80,532	77,253
Other	(477)	1,547	1,482	2,574
	35,688	36,582	82,014	79,827
EXPENSES				
Power purchases	11,497	10,688	29,308	26,572
Operating and maintenance	6,076	6,276	15,366	13,208
Amortization	3,800	3,617	7,208	7,129
Property and B.C. capital taxes	2,393	2,640	4,786	5,292
Water fees	2,168	1,816	4,073	3,634
Wheeling	902	1,021	1,809	2,106
	26,836	26,058	62,550	57,941
EARNINGS FROM OPERATIONS	8,852	10,524	19,464	21,886
INTEREST EXPENSE				
Secured debentures	3,019	2,580	6,057	4,776
Other debt	1,967	1,225	3,786	2,889
Allowance for funds used during construction	(1,361)	(498)	(2,467)	(934)
	3,625	3,307	7,376	6,731
EARNINGS BEFORE INCOME TAXES	5,227	7,217	12,088	15,155
INCOME TAXES	1,603	2,452	3,174	5,264
NET EARNINGS	3,624	4,765	8,914	9,891

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(All dollar amounts are in thousands)

	6 months ended June 30	
	2003	2002
	Unaudited $	Unaudited $
RETAINED EARNINGS, BEGINNING OF PERIOD	93,205	96,706
Net earnings	8,914	9,891
Dividends	—	(4,819)
RETAINED EARNINGS, END OF PERIOD	102,119	101,778

The accompanying notes are an integral part of these interim financial statements.

Aquila Networks Canada (British Columbia) Ltd.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(All dollar amounts are in thousands)

	3 months ended June 30		6 months ended June 30	
	2003	**2002**	**2003**	**2002**
	Unaudited $	Unaudited $	Unaudited $	Unaudited $
OPERATING ACTIVITIES				
Net earnings	3,624	4,765	8,914	9,891
Add items not involving cash				
Amortization	3,800	3,619	7,208	7,129
Future income taxes	(21)	(23)	(42)	(42)
Change in non-cash working capital	(9,993)	(1,516)	(17,659)	9,582
	(2,590)	6,845	(1,579)	26,560
INVESTING ACTIVITIES				
Property, plant and equipment	(13,850)	(12,570)	(17,717)	(21,717)
Deferred charges and other non-current assets	548	(859)	(1,946)	(930)
	(13,302)	(13,429)	(19,663)	(22,647)
FINANCING ACTIVITIES				
Common shares issued	—	—	—	15,000
Term bank loans and demand loan issued	30	8,900	—	(13,900)
Short term notes	16,143	—	21,644	—
Mortgage repaid	(143)	(98)	(248)	(194)
Dividends	—	(2,409)	—	(4,819)
	16,030	6,393	21,396	(3,913)
INCREASE (DECREASE) IN CASH	138	(191)	154	—
CASH, OPENING BALANCE	57	191	41	—
CASH, CLOSING BALANCE	195	—	195	—

The accompanying notes are an integral part of these interim financial statements.

Aquila Networks Canada (British Columbia) Ltd.

NOTES TO INTERIM FINANCIAL STATEMENTS
For the six months ended June 30, 2003
(All tabular dollar amounts are in thousands, unless otherwise notes)

1. BASIS OF PRESENTATION

These interim financial statements have been prepared in accordance with Canadian generally accepted accounting principles for interim financial statements and do not include all of the disclosures normally found in the annual financial statements for Aquila Networks Canada (British Columbia) Ltd. (''ANCBC'' or the ''Company'') (formerly UtiliCorp Networks Canada (British Columbia) Ltd.). These interim financial statements should be read in conjunction with the Company's audited financial statements for the year ended December 31, 2002.

These financial statements have been prepared following the same accounting policies and methods as those used in preparing the most recent annual financial statements. The Company is regulated by the British Columbia Utilities Commission (''BCUC''). The BCUC administers acts and regulations, pursuant to the Utilities Commission Act, covering such matters as tariffs, rates, construction, operations, financing and accounting. The timing of ANCBC's recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using Canadian generally accepted accounting principles for entities not subject to rate regulation.

2. USE OF ESTIMATES

The preparation of financial statements in accordance with generally accepted accounting principles requires management to make estimates and assumptions 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 period. Certain estimates are necessary since the regulatory environment in which the Company operates often requires amounts to be recorded at estimated values until finalization and adjustment, if any, is determined pursuant to subsequent regulatory decisions or other regulatory proceedings. Due to the inherent uncertainty in making such estimates, actual results reported in future periods could differ materially from those estimated. Interim financial statements necessarily employ a greater use of estimates than the annual financial statements.

3. SEASONAL NATURE OF OPERATION

Interim results will fluctuate due to the seasonal demands for electricity, the movements of electricity prices and the timing and recognition of regulatory decisions. Consequently, interim results are not necessarily indicative of annual results.

4. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	Net Book Value 2003	Net Book Value 2002
Generation	$ 99,764	$ 32,049	$ 67,715	$ 68,837
Substations	92,761	33,775	58,986	54,724
Transmission	75,198	19,436	55,762	56,518
Distribution	182,478	56,513	125,965	116,395
General	66,488	24,373	42,115	42,767
Construction work in progress	77,172	—	77,172	76,774
Total	$593,861	$166,146	$427,715	$416,015

5. INCOME TAXES

Interim period income tax expense is calculated by applying to the interim period's pre-tax income an estimated average annual effective income tax rate of 26.3%. The estimated average annual income tax rate reflects tax rate structure expected to be applicable to the full year's earnings.

CERTIFICATE OF FORTIS INC.

Dated September 29, 2003

This short form prospectus, together with the documents and information incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under securities legislation of all of the provinces of Canada. For the purpose of the Province of Québec, this simplified prospectus, as supplemented by the permanent information record, contains no misrepresentation likely to affect the value or the market price of the securities to be distributed.

(Signed) *H. Stanley Marshall*
President and
Chief Executive Officer

(Signed) *Karl W. Smith*
Vice-President, Finance and
Chief Financial Officer

On behalf of the Board of Directors

(Signed) *Geoffrey F. Hyland*
Director

(Signed) *Bruce Chafe*
Director

CERTIFICATE OF THE UNDERWRITERS

Dated September 29, 2003

To the best of our knowledge, information and belief, this short form prospectus, together with the documents and information incorporated herein by reference, constitutes full, true and plain disclosure of all material facts relating to the securities offered by this prospectus as required under securities legislation of all of the provinces of Canada. For the purpose of the Province of Québec, this simplified prospectus, to our knowledge, as supplemented by the permanent information record, contains no misrepresentation likely to affect the value or the market price of the securities to be distributed.

SCOTIA CAPITAL INC.

By: (Signed) *Donald A. Carmichael*

BMO NESBITT BURNS INC.	**CIBC WORLD MARKETS INC.**
By: (Signed) *James A. Tower*	By: (Signed) *David H. Williams*
NATIONAL BANK FINANCIAL INC.	**RBC DOMINION SECURITIES INC.**
By: (Signed) *William Wasson*	By: (Signed) *David Dal Bello*

TD SECURITIES INC.

By: (Signed) *James Gillis*

BEACON SECURITIES LIMITED

By: (Signed) *Lonsdale W. Holland*

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