

ENMAX
Corporation
Consolidated
Financial
Statements
2005

To the Shareholder of
ENMAX Corporation

We have audited the consolidated balance sheets of **ENMAX Corporation** as at December 31, 2005 and 2004 and the consolidated statements of earnings and retained earnings and cash flows for each of the years in the three-year period ended December 31, 2005. 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, 2005 and 2004 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2005 in accordance with Canadian generally accepted accounting principles.

Calgary, Canada
February 21, 2006

Ernst & Young LLP

Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at December 31	2005	2004
<i>(millions of Canadian dollars)</i>		<i>(restated – note 3)</i>
ASSETS		
Current assets		
Cash and cash equivalents <i>[note 6]</i>	27.1	353.3
Temporary investments, at lower of cost and market	174.8	–
Accounts receivable <i>[notes 3 and 20]</i>	329.6	226.5
Inventories	13.0	13.3
Current portion of 2000 deficiency rider receivable <i>[notes 3 and 7]</i>	–	5.3
Other current assets	2.7	1.5
	547.2	599.9
Property, plant and equipment <i>[note 8]</i>	874.9	784.9
Power purchase arrangements <i>[note 9]</i>	149.8	160.0
Intangible assets <i>[note 10]</i>	22.6	2.2
Future income tax asset <i>[note 16]</i>	180.5	173.6
Other long-term assets	11.1	9.8
	1,786.1	1,730.4
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Accounts payable and accrued liabilities <i>[notes 3, 4 and 20]</i>	190.9	169.6
Income taxes payable	22.5	34.2
Customer guarantee deposits	13.7	15.3
Current portion of long-term debt <i>[note 11]</i>	29.8	32.8
	256.9	251.9
Long-term debt <i>[note 11]</i>	204.5	219.5
Future income tax liability <i>[note 16]</i>	8.6	2.1
Other long-term liabilities <i>[note 12]</i>	10.0	18.2
Non-controlling interest <i>[note 4]</i>	0.7	–
Shareholder's equity		
Share capital <i>[note 13]</i>	280.1	280.1
Retained earnings	1,025.3	958.6
	1,305.4	1,238.7
Commitments and contingencies <i>[notes 5, 17 and 18]</i>		
	1,786.1	1,730.4

See accompanying notes to consolidated financial statements.

On behalf of the Board:



Thompson MacDonald
Chair, ENMAX Board of Directors



Paul Dawson, FCA
Chair, Audit and Finance Committee

CONSOLIDATED STATEMENTS OF EARNINGS AND RETAINED EARNINGS

Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			<i>(restated – note 3)</i>
REVENUE <i>[note 20]</i>			
Sales of electricity and natural gas	925.0	826.4	845.0
Transmission and distribution revenue	269.7	266.6	277.0
Contractual services and other	103.7	100.1	104.2
	1,298.4	1,193.1	1,226.2
COST OF SERVICES PROVIDED <i>[note 20]</i>			
Electricity and natural gas costs <i>[notes 9 and 17]</i>	653.2	517.2	487.5
Grid charges	141.7	126.6	138.6
Local access fees	73.0	68.5	68.2
Operations, maintenance and administration <i>[note 12]</i>	216.8	208.3	230.4
	1,084.7	920.6	924.7
Earnings before amortization, interest and income taxes	213.7	272.5	301.5
Amortization of property, plant and equipment	58.5	53.7	61.7
Amortization of intangible assets	1.4	0.4	0.8
Interest <i>[note 15]</i>	14.1	14.0	12.9
Earnings before income taxes and non-controlling interest	139.7	204.4	226.1
Income taxes <i>[note 16]</i>	23.4	52.2	53.1
Non-controlling interest	(0.4)	–	–
Net earnings	116.7	152.2	173.0
Retained earnings, beginning of year	958.6	856.8	733.8
Dividends	(50.0)	(50.4)	(50.0)
Retained earnings, end of year	1,025.3	958.6	856.8

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			<i>(restated – note 3)</i>
Cash provided by (used in)			
OPERATING ACTIVITIES			
Net earnings	116.7	152.2	173.0
Amortization <i>[note 9]</i>	70.1	63.7	72.6
Future income taxes <i>[note 16]</i>	(7.1)	13.9	46.4
Non-controlling interest	(0.4)	–	–
Change in unrealized market value of financial commodity contracts <i>[note 17]</i>	(1.7)	7.5	–
	177.6	237.3	292.0
Change in non-cash working capital items <i>[note 19]</i>	(97.8)	30.1	2.3
	79.8	267.4	294.3
INVESTING ACTIVITIES			
Purchase of temporary investments	(174.8)	–	–
Purchase of property, plant and equipment	(139.8)	(113.0)	(183.5)
Purchase of intangible assets	(1.8)	(0.6)	–
Proceeds on disposal of property, plant and equipment	–	–	9.8
Contributions in aid of construction	11.0	12.2	9.8
2000 deficiency rider receivable collected	5.3	47.1	45.5
Acquisitions, net of cash acquired <i>[note 4]</i>	(13.4)	–	–
Customer guarantee deposits	(1.6)	0.9	0.5
Other long-term assets	(1.0)	0.8	(10.6)
	(316.1)	(52.6)	(128.5)
FINANCING ACTIVITIES			
Dividends paid	(50.0)	(50.4)	(50.0)
Long-term debt issued (repaid)	(33.4)	91.7	(23.2)
Other long-term liabilities	(6.5)	(3.7)	5.0
	(89.9)	37.6	(68.2)
Increase (decrease) in cash and cash equivalents	(326.2)	252.4	97.6
Cash and cash equivalents, beginning of year	353.3	100.9	3.3
Cash and cash equivalents, end of year <i>[note 6]</i>	27.1	353.3	100.9
Cash interest paid	16.1	15.4	14.6
Cash taxes paid (recovered)	62.0	10.6	(2.1)

See accompanying notes to consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF BUSINESS

ENMAX Corporation (“ENMAX” or the “Corporation”), a wholly owned subsidiary of The City of Calgary (“The City”), was incorporated under the Business Corporations Act (Alberta) in July 1997. The Corporation was formed to carry on the electric utility transmission and distribution operations previously carried on by the Calgary Electric System (“CES”), a former department of The City, in contemplation of the emerging deregulated electric industry in Alberta. As such, operations of the Corporation began on January 1, 1998 with the transfer of substantially all of the assets and liabilities of the CES by The City into the Corporation at net book value for consideration of one common share issued to The City.

The Corporation operates in two segments representing separately managed business units, each of which offers different products and services.

ENMAX Energy

ENMAX Energy Corporation is an unregulated, wholly owned subsidiary established to carry out all energy supply and retail functions in its own right and through eight subsidiaries and one affiliated company.

ENMAX Power

ENMAX Power Corporation is a regulated, wholly owned subsidiary established to carry out all electricity distribution and transmission service functions in its own right and through two subsidiaries providing unregulated power services.

Various components of the electric utility industry are regulated by the Alberta Energy and Utilities Board (“EUB”). Effective January 1, 1996, the provincial government passed into law the *Electric Utilities Act* (“EUA”). The Act provides for the sale of all power from generators for use in Alberta to the Power Pool of Alberta (Power Pool) for resale to distribution companies at a bid price that matches demand with supply. The EUA was amended in 1998 to provide for the introduction of retail competition into Alberta’s electric industry, commencing in January 2001.

The Corporation operates in various service territories in Alberta and British Columbia. In certain areas, municipalities act as regulators to approve the Distribution Tariff (“DT”) and the Regulated Rate Tariff (“RRT”). Prior to 2003, Calgary City Council, as regulator of ENMAX Power, approved the DT and RRT for eligible customers within the City of Calgary. In 2003, the Electrical Utility Regulation Committee (“EURC”), established by Calgary City Council, was the regulator of ENMAX Power and as such, approved the RRT for eligible customers within the City of Calgary. An amendment to the EUA in June 2003 changed the regulatory jurisdiction of municipally owned utilities with affiliated retailers operating outside of the municipality’s service area from the municipality to the EUB effective January 1, 2004.

Transmission companies lease their transmission facilities to the Alberta Electric System Operator (“AESO”), which administers transmission services needed to serve customers throughout Alberta and charges a uniform tariff to all distribution companies. The tariff associated with ENMAX Power’s transmission facilities was regulated by the Alberta Department of Energy (“DOE”). Effective January 1, 2006, this tariff is regulated by the EUB.

The EUA provides for the EUB's regulation of the Corporation's utility operation and requires the EUB to approve, among other things, customer rates and capital expenditures. The EUA also entitles the Corporation an opportunity to recover all reasonable and prudent costs incurred in providing electricity service to its customers, including a just and reasonable return on its rate base. The rate base consists of the net assets required by the Corporation to provide service to customers.

The determination of the forecast return on rate base, together with the forecast of all reasonable and prudent costs, establishes the revenue requirement upon which the Corporation's customer rates are determined through a general rate hearing. In between general rate hearings, customer rates may be adjusted, on an interim basis, through an abbreviated rate change application. The forecast cost of capital reflected in customer rates for 2005 was 7.1% (2004 – 7.9%).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). The consolidated financial statements include the accounts of the Corporation and its subsidiaries, as well as its proportionate share of the accounts of its joint ventures.

The assets and liabilities, results of operations and cash flows of the subsidiaries are included in the consolidated financial statements of the Corporation. The non-controlling interest is presented net of income taxes in the consolidated statement of earnings.

All intercompany accounts and transactions have been eliminated, except as described in note 3.

Measurement uncertainty

The preparation of the Corporation's financial statements, in accordance with generally accepted accounting principles, requires management to make estimates that affect the reported amounts of revenues, expenses, assets and liabilities as well as the disclosure of contingent assets and liabilities at the financial statement date.

On January 1, 2001, the Alberta retail electricity marketplace opened to retail competition. The various systems and procedures used by third parties to provide load and settlement data to retailers across the province have been challenged to completely and accurately capture all customer movement, load classification and consumption data. In addition, by regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until eight months after the month in which such electricity was consumed. The data and associated processes and systems are complex and are used by the Corporation to estimate electricity revenues and costs, including unbilled consumption. The Corporation's estimation procedures will not necessarily detect errors in underlying data provided by industry participants including wire service providers and load settlement agents.

For determining potential asset impairments and certain disclosures, the Corporation is required to estimate the fair value of certain assets and obligations. Estimates of fair values are mainly based on discounted cash flow techniques employing estimated cash flows based on a number of assumptions and using an appropriate

discount rate. Financial instruments that do not satisfy the conditions required for hedge accounting are recorded at fair value, which may, due to market illiquidity, require the use of estimated future prices.

The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be uncollectible. It is based on a number of factors including the aging of receivables, historical write-offs within customer groups, assessments of the collectibility of amounts from individual customers and general economic conditions.

Amortization is an estimate to allocate the cost of an asset over its estimated useful life on a systematic and rational basis. Estimating the appropriate useful lives of assets requires significant judgment and is generally based on estimates of common life characteristics of common assets.

Measurement of the Corporation's asset retirement obligation requires the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required and related future cash flows.

Income taxes and amounts in lieu of income taxes are determined based upon estimates of the Corporation's current income taxes and estimates of future taxes resulting from temporary tax differences. Future income tax assets are assessed to determine the likelihood that they will be recovered from future taxable income. To the extent that recovery is not considered likely, a valuation allowance will be recorded and charged against income in the period that the allowance is created or revised.

Certain estimates are necessary since the regulatory environment that the Corporation operates in often requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions, or other regulatory proceedings.

Adjustments to previous estimates, which will impact net income and could be material, will be recorded in the period they become known.

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and balances with banks, and investments in money market instruments with maturities within three months from the date of acquisition.

Temporary investments

Temporary investments include marketable securities (consisting primarily of bonds, stocks and short-term deposits) and are carried at the lower of cost and market value. At December 31, 2005, the fair market value was \$179.0 million (2004 – nil). The effective interest rate at December 31, 2005 on temporary investments was 3.8% (2004 – nil).

Inventories

Inventory of supplies and materials is valued at the lower of cost and net recoverable cost. Cost is determined using the weighted average cost method.

Property, plant and equipment

Property, plant and equipment are recorded at cost, which includes direct labour, material, equipment charges, overhead and allowance for funds used during construction ("AFUDC"). The AFUDC is charged and recovered at approved rates to customers over the service life of the assets, as described in note 3.

Amortization of property, plant and equipment is recorded on a straight-line basis over the estimated useful life of the asset class at the following rates:

Buildings and site development	2.13 % – 20.00 %
Transmission, distribution and substation equipment	0.96 % – 14.37 %
Generation equipment	3.33 % – 5.00 %
Tools, systems and equipment	3.33 % – 33.33 %
Vehicles	2.65 % – 13.71 %

Original costs of retired regulated depreciable assets are charged and the related net disposal proceeds are credited to accumulated amortization. As a result, all gains and losses on the disposal of regulated depreciable assets are deferred and amortized over the estimated remaining service life of the related assets, as described in note 3. Gains and losses on the disposal of non-regulated non-depreciable assets are recognized in the year of disposal.

Intangible assets

Intangible assets are recorded at cost and amortization is recorded on a straight-line basis over the estimated useful lives of the assets at the following rates:

Customer lists and contracts	0 % – 10.90 %
Land easements, rights and lease options	0 % – 3.34 %

Intangible assets with indeterminate lives are assessed annually for impairment.

Asset impairment

Long-lived assets are tested for impairment at least annually or at such times when events or circumstances indicate that the carrying amount may not be recoverable. An impairment loss would be recognized if the carrying amount exceeds the fair value of an asset, determined as the sum of the undiscounted cash flows expected to result from the asset's use and eventual disposition. The loss, if any, is measured as the amount by which the carrying amount exceeds the fair value of the asset.

The fair values are estimated using accepted valuation methodologies such as discounted future net cash flows, earnings multiples or prices for similar assets, whichever is most appropriate under the circumstances.

Asset retirement obligation

The Corporation recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of a liability for an asset retirement obligation is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows are reflected through charges to earnings. A gain or loss may be incurred upon settlement of the liability.

On December 31, 2005, the Corporation's asset retirement obligations relate to costs associated with the removal and decommissioning of its fibre optic network and proportionate share of the joint venture's wind turbines. In addition, the Corporation has an obligation to decommission its electricity transmission and distribution assets in

Alberta and the run-of-river hydroelectric generating station in British Columbia; however, the likely timing, method and cost of such future decommissioning activities is unknown and cannot be reasonably estimated. Accordingly, the Corporation is unable to estimate the fair value of this asset retirement obligation and has not recorded it in the consolidated financial statements. The obligation will be recorded when sufficient information is available to reasonably estimate the settlement date and the cost and method of settlement.

Contributions in aid of construction

Under various statutory requirements and agreements with customers and developers, the Corporation receives contributions in aid of construction (“CIAC”) in the form of cash contributions. Such contributions are deferred and amortized on the same basis as, and offset the amortization charge of, the assets to which they relate.

Power Purchase Arrangements

The cost of the Power Purchase Arrangements (“PPAs”) has been recorded on the consolidated balance sheets as a long-term asset. The cost is amortized to electricity costs over the life of the contracts based on future cash flow estimates at the time of acquisition.

Revenue recognition

Revenues are recognized on an accrual basis and include an estimate of services provided but not yet billed.

Income tax

The Corporation and its subsidiaries are municipally owned and are generally not subject to federal and provincial income taxes. Those subsidiaries that are outside the jurisdiction of the EUA regulations are taxable under the *Income Tax Act* (Canada). The Corporation records income tax expense based on an Alberta regulation to the EUA that requires municipally owned entities to make payments in lieu of income taxes (“PILOT”) on certain portions of their operations. ENMAX uses the asset and liability method of accounting for income taxes and amounts in lieu of income taxes. Under this method, current income taxes are recognized for the estimated income taxes payable or recoverable for the current year. Future income tax assets and liabilities are recognized for the future tax consequences attributable to the difference between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future income tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on future tax assets and liabilities is recognized in income in the period that includes the date of enactment or substantive enactment.

Financial instruments

The fair values of cash and cash equivalents, accounts receivable, accounts payable and customer guarantee deposits approximate the carrying amounts of these instruments due to their short period to maturity.

Hedging

In conducting its business, the Corporation uses various instruments, including forward contracts, swaps and options, to manage the risk arising from fluctuations in commodity prices. The Corporation also uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Corporation's exposure to fluctuations in electricity and natural gas prices. Under these instruments, the Corporation agrees to exchange with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified time frame.

Financial instruments are tested for effectiveness when designated as a hedge and on an ongoing basis. Effectiveness is measured with reference to the risk management objective and strategy for the financial instrument. For instruments that qualify for hedge accounting, gains and losses are recognized in income in the same period and in the same financial statement category as the income or expense from the hedged position. Otherwise, the instruments are recognized on the balance sheet, in other long-term liabilities and measured at fair value, with changes in fair value recognized in income through a charge to earnings as cost of electricity.

Employee benefit plans

The Corporation sponsors pension plans that contain both defined benefit and defined contribution provisions. The cost of defined benefit pensions and other post-employment benefits earned by employees is actuarially determined using the projected benefit method pro-rated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair market value. For the purpose of calculating the expected return on plan assets for the net benefit cost, a market-related value is used. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service lifetime of employees active at the date of amendment. The excess of the cumulative, unamortized net actuarial gain or loss over 10% of the greater of the benefit obligation and the fair value of plan assets at the beginning of the year is amortized over the average remaining service lifetime of the active employees.

3. RECENT ACCOUNTING PRONOUNCEMENTS**Restatement of prior periods relating to rate regulation**

Commencing in 2005, intercompany profits on asset construction work performed by an ENMAX subsidiary for the regulated operations of ENMAX are deemed to be realized to the extent that the transfer price is recognized for rate-making purposes by the regulator. Comparative periods have been restated to conform to this treatment. The impact on property, plant and equipment and retained earnings at December 31, 2003 is an increase of \$10.1 million. The impact on net earnings in 2005 is an increase of \$4.3 million (2004 – \$4.9 million; 2003 – \$4.9 million).

Financial statement effects of rate regulation

In May 2005, the Canadian Institute of Chartered Accountants issued Accounting Guideline 19, Disclosures by Entities Subject to Rate Regulation (AcG-19). AcG-19 expands disclosure requirements relating to circumstances in which the accounting for transactions or events is affected by rate regulation. The guideline is effective for fiscal years ending on or after December 31, 2005.

Under regulatory accounting, the timing of recognition of certain assets, liabilities, revenues and expenses may differ from what is otherwise expected under Canadian GAAP for non-regulated operations.

Regulatory assets and liabilities

As at December 31	2005	2004
<i>(millions of Canadian dollars)</i>		
Regulatory assets		
Distribution assets – intercompany profit on underground residential development <i>[note 8]</i>	18.6	14.7
Accounts receivable – purchased power price variance	4.2	–
2000 deficiency rider receivable <i>[note 7]</i>	–	5.3
Total regulatory assets	22.8	20.0
Regulatory liability		
Accounts payable and accrued liabilities – purchased power price variance	–	1.5
Total regulatory liability	–	1.5

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process.

Distribution assets for the regulated operations of ENMAX include intercompany profit relating to construction work performed by an ENMAX subsidiary. Such profit is deemed to be realized to the extent that the transfer price is recognized for rate-making purposes by the regulator and included in the capital cost. In the absence of rate regulation, generally accepted accounting principles would require that intercompany profits be eliminated upon consolidation. The impact on current year earnings would be a reduction of \$4.3 million (2004 – \$4.9 million; 2003 – \$4.9 million), representing the profit on these services. The balances for property, plant and equipment and retained earnings at December 31, 2005 would further be reduced by \$18.6 million (2004 – \$14.7 million).

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year, when their final disposition is decided. ENMAX recognizes purchased power cost variances as a regulatory asset or liability, based on the expectation that amounts held from one year to the next for rate-setting purposes

will be approved for collection from, or refund to, future customers. The regulatory asset (2004 – liability) represents the excess of actual over forecast (2004 – forecast over actual) purchased power costs. In the absence of rate regulation, generally accepted accounting principles would require that actual purchased power costs be recognized as an expense when incurred. In this case, operating results for 2005 would have been \$4.2 million lower (2004 – \$1.5 million higher; 2003 – nil). The regulatory asset (2004 – liability) is included in accounts receivable (2004 – accounts payable).

For certain of the regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. For example, ENMAX's treatment of purchased power costs is dependent on the continued use of an automatic adjustment mechanism for regulatory purposes, and would require reconsideration if the regulator decided to discontinue the use of this mechanism or to require the Corporation to absorb cost variances in a particular year. Similarly, there is a risk that the regulator may disallow a portion of certain costs incurred in the current year for recovery through future rates, or disagree with the proposed recovery period.

Other items affected by rate regulation

Current regulations exclude transmission, distribution and rate-regulated electricity sales earnings from income taxes. Accordingly, ENMAX has not recognized current or future income taxes on these earnings. In the event regulations change, it would be expected that when these amounts became payable, they would be recovered through future rate revenues. In the absence of rate regulation, generally accepted accounting principles require the recognition of current and future income tax liabilities and future tax assets.

Gains and losses on the disposal and retirement of regulated depreciable assets are deferred and amortized over the estimated remaining service life of the related assets, through a charge to accumulated amortization equal to the net book value of the disposed or retired asset. In the absence of rate regulation, under generally accepted accounting principles, the difference between the proceeds and net book value would be charged or credited to earnings in the period the asset is disposed of or retired.

The regulator permits an allowance for funds used during construction (AFUDC), based on ENMAX's weighted-average cost of capital, to be included in the rate base. AFUDC is also included in the cost of property, plant and equipment for financial reporting purposes, and is depreciated over future periods as part of the total cost of the related asset, based on the expectation that depreciation expense, including the AFUDC component, will be approved for inclusion in future customer rates. Since AFUDC includes not only an interest component, but also a cost-of-equity component, it exceeds the amount allowed to be capitalized in similar circumstances in the absence of rate regulation. AFUDC and capitalized interest totaling \$2.3 million (2004 – \$2.3 million) were included in property, plant and equipment.

Financial instruments and comprehensive income

In January 2005, the Canadian Institute of Chartered Accountants issued Handbook Section 1530, "Comprehensive Income", Section 3251, "Equity", Section 3855, "Financial Instruments – Recognition and Measurement" and Section 3865, "Hedges".

Under the new standards, a new location for recognizing certain gains and losses – other comprehensive income – has been introduced, providing an ability for certain gains and losses arising from changes in the fair value of assets and liabilities to be temporarily recorded outside the income statement, but in a transparent manner; all financial instruments, including derivatives, are to be included on a company's balance sheet and measured in most cases at their fair values; and existing requirements for hedge accounts are expanded. The guidance will apply for interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006. Earlier adoption will be permitted only as of the beginning of a fiscal year. The Corporation is evaluating the impact of these recently issued standards on its consolidated financial statements for periods after 2005.

4. ACQUISITIONS

In the first quarter of 2005, ENMAX purchased 100 per cent of the outstanding shares of Valeo Power Corporation (“Valeo”), a privately held electricity retailer and services company. The primary assets of the company are commercial and industrial electricity contracts. The share purchase agreement included contingent consideration based on earnings levels achieved during 2005. Earnings for the year ended December 31, 2005 exceeded the targets outlined in the share purchase agreement, and in January 2006 the remaining consideration was paid. The purchase price was finalized and the remaining consideration allocated to intangible assets relating to customer relations and lists acquired in the transaction.

In the second quarter of 2005, the Corporation acquired 99 per cent of Furry Creek Power Ltd. (“Furry Creek”), which owns an 11 megawatt run-of-river hydro electric facility located north of Vancouver, British Columbia. In addition, ENMAX and Vancouver-based Eaton Power Corporation entered into a business venture to develop run-of-river hydro projects in British Columbia over the next five years. ENMAX invested \$2.0 million in exchange for a 65 per cent interest in the newly formed company, Hydromax Energy Ltd. The company's assets include a series of run-of-river hydro projects in the early stages of development.

ENMAX accounted for these acquisitions using the purchase method and the results of operations have been included in the consolidated financial statements from the effective dates of the acquisitions. The allocation of the purchase prices is as follows:

Net assets acquired

(millions of Canadian dollars)

Current assets	1.3
Property, plant and equipment	19.7
Intangible assets	20.0
Other long-term assets	0.3
Current liabilities	(4.7)
Long-term debt <i>[note 11]</i>	(15.4)
Future income tax liabilities	(6.7)
Non-controlling interest	(1.1)
Total cash consideration, net of cash acquired of 2.7	13.4

5. JOINT VENTURE INVESTMENT

In 2002, ENMAX entered into a joint venture agreement with Vision Quest Windelectric Inc. to build and operate 114 wind turbines in southern Alberta. The wind farm began generating electricity in 2003 and ENMAX has a 50% ownership interest. ENMAX has also agreed to purchase the output from the wind farm under a 20-year power purchase agreement.

Summarized Financial Information

As at December 31	2005	2004	
<i>(millions of Canadian dollars)</i>			
Balance sheet			
Accounts receivable	0.6	0.7	
Other current assets	0.1	0.1	
Property, plant and equipment	45.8	47.5	
Future income taxes	(0.1)	(1.1)	
Other long-term liabilities	(0.3)	(0.3)	
Proportionate share in net assets of joint venture	46.1	46.9	
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Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			
Earnings			
Revenue	7.5	6.9	4.2
Costs and expenses	(2.1)	(1.4)	(0.9)
Amortization	(1.7)	(1.7)	(0.8)
Income taxes recovery (expense)	0.2	(0.8)	(0.3)
Proportionate share in net earnings of joint venture	3.9	3.0	2.2
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Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			
Cash flows			
Operating activities	4.7	5.1	28.9
Investing activities	–	(0.3)	(43.3)
Financing activities	–	0.3	–
Proportionate share in the increase (decrease) in cash and cash equivalents of joint venture	4.7	5.1	(14.4)

6. CASH AND CASH EQUIVALENTS

As at December 31	2005	2004
<i>(millions of Canadian dollars)</i>		
Cash on hand and balances with banks	3.3	3.8
Short-term investments	23.8	349.5
Cash and cash equivalents	27.1	353.3

The effective interest rate at December 31, 2005 on short-term investments was 3.3% (2004 – 2.6%).

7. 2000 DEFICIENCY RIDER RECEIVABLE

The 2000 deficiency rider receivable represents revenue shortfalls in 2000 attributable to unexpectedly high energy costs. These costs were recovered, with associated interest, in 2002 through 2004 via a rider on the DT. Collections in 2005 amounted to \$5.3 million (2004 – \$47.1 million; 2003 – \$45.5 million). All amounts relating to the rider have now been fully recovered.

8. PROPERTY, PLANT AND EQUIPMENT

As at December 31

	2005		
	Cost	Accumulated amortization	Net book value
<i>(millions of Canadian dollars)</i>			
Transmission, distribution and substation equipment	1,058.1	(388.5)	669.6
Tools, systems and equipment	230.2	(115.1)	115.1
Buildings and site development	107.0	(22.4)	84.6
Construction in progress	72.4	–	72.4
Generation equipment	69.0	(4.9)	64.1
Land	17.7	–	17.7
Vehicles	16.7	(10.2)	6.5
	1,571.1	(541.1)	1,030.0
Contributions in aid of construction	(199.8)	44.7	(155.1)
	1,371.3	(496.4)	874.9

As at December 31

	2004		
	Cost	Accumulated amortization	Net book value
<i>(millions of Canadian dollars)</i>			
Transmission, distribution and substation equipment	983.3	(367.1)	616.2
Tools, systems and equipment	220.0	(95.2)	124.8
Buildings and site development	101.8	(19.6)	82.2
Construction in progress	41.9	–	41.9
Generation equipment	50.3	(2.5)	47.8
Land	16.7	–	16.7
Vehicles	15.8	(10.6)	5.2
	1,429.8	(495.0)	934.8
Contributions in aid of construction	(189.7)	39.8	(149.9)
	1,240.1	(455.2)	784.9

9. POWER PURCHASE ARRANGEMENTS

As part of the Government of Alberta auction of electrical generation PPAs, the Corporation purchased from a third-party generator the rights to the physical output from four units (contract expired January 1, 2004) for \$77.3 million and two units (contract expiring December 31, 2020) for \$247.7 million. The Corporation is entitled to an estimated average 5.9 million megawatt hours (MWh) of electricity per year from 2005 through 2020. The megawatts available decrease yearly as the units age. In return for the output, the Corporation is obligated to make monthly fixed and variable payments (see Note 18).

Electricity costs include the following items related to the PPAs:

Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			
Fixed and variable costs	191.7	189.4	283.1
Amortization of purchase price	10.2	9.6	10.1
	201.9	199.0	293.2

Scheduled PPA amortization charges are as follows:

	2006	2007	2008	2009	2010	Thereafter
<i>(millions of Canadian dollars)</i>						
	8.9	8.4	7.5	8.5	8.5	108.0

10. INTANGIBLE ASSETS

As at December 31	2005		
	Cost	Accumulated amortization	Net book value
<i>(millions of Canadian dollars)</i>			
Customer lists and contracts	20.5	(3.5)	17.0
Land easements, rights and lease options	2.2	(0.1)	2.1
Renewable energy certificates and water licences	3.5	–	3.5
	26.2	(3.6)	22.6

As at December 31	2004		
	Cost	Accumulated amortization	Net book value
<i>(millions of Canadian dollars)</i>			
Customer lists and contracts	2.7	(2.1)	0.6
Land easements, rights and lease options	0.8	(0.1)	0.7
Renewable energy certificates and water licences	0.9	–	0.9
	4.4	(2.2)	2.2

11. LONG-TERM DEBT

As at December 31	2005	2004	Weighted average interest rates
<i>(millions of Canadian dollars)</i>			
Debtures, with remaining terms of:			
Less than 5 years	40.7	52.9	7.4%
5 – 10 years	121.4	76.3	6.0%
10 – 15 years	57.3	123.1	4.5%
Non-recourse term financing	14.9	–	7.6%
	234.3	252.3	6.0%
Less: current portion	29.8	32.8	
	204.5	219.5	

Debentures

The debentures were initially issued by The City on behalf of the CES pursuant to City by law authorizations prior to January 1, 1998. Pursuant to the Master Agreement between the Corporation and The City, the debentures were included in the assumed liabilities upon transfer of substantially all of the assets and liabilities of the CES from The City to the Corporation at January 1, 1998. In accordance with a debt management service level agreement between the Corporation and The City, The City shall continue to service the existing debentures through the disbursement of principal and interest payments. The Corporation is required to reimburse The City for all principal repayments and interest payments with respect to the debentures on the same day as The City disburses the payments to the debt holders. In addition, the Corporation is required to pay a loan guarantee and administration fee to The City of 0.25% on the average monthly outstanding debenture balance held by The City on behalf of the Corporation. In 2005, the Corporation issued no debentures (2004 – \$119.5 million; 2003 – nil).

Non-recourse financing

The non-recourse financing was assumed with the acquisition of Furry Creek Power Ltd. in the second quarter of 2005 and represents the Corporation’s share, through its subsidiary ENMAX Green Power Inc., of loans for the construction of the 11 megawatt hydroelectric facility. \$14.4 million of the debt bears interest at a fixed rate of 7.3% and the remaining \$0.5 million at a floating rate equal to the lender’s prime interest rate plus a spread of 10.0%. Currently, ENMAX Green Power Inc. has provided a limited recourse guarantee to the extent of its interest in the shares of Furry Creek Power Ltd. The construction loan will be converted to project debt in 2006. Upon conversion, a charge against project assets, which have a carrying value of \$18.9 million, will be provided as security.

Principal repayments

The required repayments of principal on the long-term debt at December 31, 2005 are as follows:

(millions of Canadian dollars)

	2006	2007	2008	2009	2010	Thereafter
	29.8	29.9	22.3	22.1	19.6	110.6

ENMAX has unsecured credit facilities amounting to \$350.0 million to fund general operating requirements and to provide liquidity support for commercial paper and commodity marketing programs. At December 31, 2005 and 2004, no amounts were drawn on the credit facilities or issued under the commercial paper program, other than to support issued letters of credit (see Note 18).

Fair value

The estimated fair value of the Corporation’s long-term debt as at December 31, 2005 is \$254.3 million (2004 – \$269.6 million). Calculation of the estimated fair value of the debt is based on current lending rates of the primary lender to The City, the Alberta Municipal Financing Corporation, for the debentures with comparable terms and maturities.

12. EMPLOYEE FUTURE BENEFITS

The Corporation established a registered pension plan on January 1, 2001 to provide future pension benefits for its employees. Prior to 2001, employees of the Corporation participated under the provisions of the Local Authorities Pension Plan. The assets and liabilities attributable to these employees were transferred to the new plan effective January 1, 2001. The registered pension plan covers substantially all employees and includes both defined benefit ("DB") and defined contribution ("DC") provisions. The DB provisions provide a pension based on years of service and highest average earnings over five consecutive years of employment. DB pension benefits under the registered plan will increase annually by 60 per cent of the Consumer Price Index for Alberta. Under the DC provisions, employer contributions are based on the participating members' pensionable earnings and contribution levels.

The Corporation also sponsors a supplemental pension plan providing an additional DB pension based on years of service and highest average earnings (including incentive pay) to both DB and DC members whose benefits are limited by maximum pension rules under the *Income Tax Act*. The supplemental pension plan benefits do not automatically increase. In addition, the Corporation provides employees with other post-retirement benefits other than pensions, including extended health and dental benefits beyond those provided by government-sponsored plans, life insurance and a lump-sum allowance payable at retirement.

ENMAX measures its accrued benefit obligation and the fair value of plan assets for accounting purposes as at December 31 of each year. Actuarial valuations are conducted every three years. The most recent actuarial valuation was prepared as at December 31, 2004. As the DB plan has a solvency ratio of less than 85 per cent, actuarial valuations would normally be required annually. During the year ended December 31, 2005, the Corporation applied for and received an exemption from Alberta Finance waiving this requirement. The next required valuation will be performed as of December 31, 2007.

The market-related value of assets was calculated based on the average of the adjusted market value of assets for the current and three preceding years. The adjusted market values were determined from the preceding three year-end market values accumulated to the end of the fiscal year in question with net contributions less distributions and assumed investment return.

Total cash payments for employee future benefits for 2005, consisting of cash contributed by ENMAX under the DB and DC provisions of the registered pension plan and cash payments directly to beneficiaries of the Corporation's unfunded other benefit plans, were \$16.3 million (2004 – \$13.3 million, 2003 – \$4.4 million).

For the year ended December 31, 2005, the total expense for the DC provisions of the plan is \$2.7 million (2004 – \$2.6 million; 2003 – \$2.9 million).

In 2003, the Corporation outsourced its billing and customer care function and about 320 ENMAX employees became employees of the service provider. The event resulted in the transfer to the service provider of pension assets and pension and other benefit liabilities relating to the affected employees. This event was considered a settlement and curtailment for 2003 accounting purposes.

Information about the DB provisions of the plan, including the supplemental pension plan and the post-retirement non-pension benefit plan, is as follows:

Years ended December 31	2005		2004	
	Pension benefit plans	Other benefit plans	Pension benefit plans	Other benefit plans
<i>(millions of Canadian dollars)</i>				
Change in benefit obligation				
Benefit obligation – beginning of year	122.8	4.6	107.1	4.3
Current service cost	3.5	0.3	3.3	0.3
Employee contributions	1.2	–	1.2	–
Benefits paid	(8.5)	(0.2)	(4.7)	(0.2)
Interest cost	7.3	0.3	7.0	0.3
Actuarial loss/(gain)	21.1	0.5	8.9	(0.1)
Benefit obligation – end of year	147.4	5.5	122.8	4.6
Change in plan assets				
Plan assets at market-related value – beginning of year	90.4	–	81.0	–
Employer contributions	12.2	–	10.2	–
Employee contributions	1.2	–	1.2	–
Benefits paid	(7.6)	–	(4.3)	–
Return on plan assets	6.8	–	6.1	–
Experience loss	(0.4)	–	(3.8)	–
Plan assets at market-related value – end of year	102.6	–	90.4	–
Deferred investment gain	11.0	–	0.7	–
Plan assets at fair value – end of year	113.6	–	91.1	–
Funded status – plan deficit	(33.8)	(5.5)	(31.7)	(4.6)
Unamortized transitional asset	(2.0)	(0.1)	(2.4)	(0.1)
Unamortized experience losses	45.1	1.4	36.1	1.1
Accrued benefit asset/(liability), net of valuation allowance of nil	9.3	(4.2)	2.0	(3.6)

The accrued benefit balance is included in ENMAX's balance sheet in other long-term liabilities. Plan assets at December 31, 2005 consist of Canadian equity securities (49%), foreign equity securities (20%), long-term fixed income securities (28%) and cash and short-term securities (3%).

The significant weighted-average actuarial assumptions adopted in measuring the Corporation's accrued benefit obligations and net benefit plan expense are as follows:

Years ended December 31	2005		2004		2003	
	Pension benefit plans	Other benefit plans	Pension benefit plans	Other benefit plans	Pension benefit plans	Other benefit plans
Accrued benefit obligation at December 31:						
Discount rate	5.00%	5.00%	6.00%	6.00%	6.25%	6.25%
Rate of compensation increase	3.60%	3.60%	3.60% ⁽¹⁾	3.60%	3.60% ⁽¹⁾	3.60%
Benefit cost for year ended December 31:						
Discount rate	6.00%	6.00%	6.25%	6.25%	6.25%	6.25%
Expected long-term rate of return on plan assets	7.25%	7.25%	7.25%	N/A	7.25%	N/A
Rate of compensation increase	3.60%	3.60%	3.60% ⁽¹⁾	3.60%	3.60% ⁽¹⁾	3.60%

(1) Plus age-related merit/promotion increases.

For measurement purposes, a 10% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005 (2004 – 10%; 2003 – 9%). The rate was assumed to decrease gradually to 5% in 2014 and to remain at that level thereafter. The per capita cost of covered dental benefits was assumed to increase by 4.5% per year.

The Corporation's net benefit cost is as follows:

Years ended December 31	2005		2004		2003	
<i>(millions of Canadian dollars)</i>	Pension benefit plans	Other benefit plans	Pension benefit plans	Other benefit plans	Pension benefit plans	Other benefit plans
Current service cost	3.5	0.3	3.4	0.3	3.3	0.3
Interest cost	7.3	0.3	7.0	0.3	6.6	0.3
Actual return on assets	(17.2)	–	(2.5)	–	(6.0)	–
Actuarial losses/(gains)	21.6	(0.7)	9.1	(0.2)	5.3	1.4
Difference between expected and actual return	10.4	–	(3.6)	–	0.3	–
Difference between recognized and actual actuarial (losses)/gains	(18.9)	0.8	(7.1)	0.2	(3.7)	(1.3)
Settlement loss	–	–	–	–	1.5	0.1
Amortization of net transitional asset	(0.4)	–	(0.4)	–	(0.4)	–
Net benefit plan expense	6.3	0.7	5.9	0.6	6.9	0.8

In 2003, ENMAX implemented a cost restructuring to reduce about 200 employee positions, of which about half were unfilled or vacant. Severance and termination benefits recorded in 2003 for this cost restructuring amounted to \$1.9 million.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plan. A one-percentage-point change in the assumed health care cost trend rate would have the following effect for 2005:

Effect of change in health care cost trend rate

<i>(millions of Canadian dollars)</i>	Other benefit plans	
	1% increase	1% decrease
Increase (decrease) in service cost for year ended December 31	0.02	(0.02)
Increase (decrease) in interest cost for year ended December 31	0.01	(0.01)
Increase (decrease) in accrued benefit obligation at December 31	0.18	(0.17)

13. SHARE CAPITAL

	Number of shares	Amount <i>(millions of Canadian dollars)</i>
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Issued on incorporation (one dollar)	1	–
Issued on transfer of net assets from CES <i>[see Note 1]</i>	1	278.2
Issued on transfer of billing and customer care assets from The City in 2001	1	1.9
Outstanding at December 31, 2005 and 2004	3	280.1

14. SEGMENTED INFORMATION⁽¹⁾

	ENMAX Energy	ENMAX Power	ENMAX Corporate ⁽²⁾	Consolidated totals
Year ended December 31, 2005				
<i>(millions of Canadian dollars)</i>				
Revenue				
Sales of electricity and natural gas	1,115.1	–	(190.1)	925.0
Transmission and distribution revenue	–	269.7	–	269.7
Contractual services and other	36.6	68.7	(1.6)	103.7
Total revenue	1,151.7	338.4	(191.7)	1,298.4
Cost of services provided				
Electricity and natural gas costs ⁽³⁾	653.2	–	–	653.2
Grid charges	276.9	56.4	(191.6)	141.7
Local access fees	0.1	72.9	–	73.0
Operations, maintenance and administration	105.3	121.0	(9.5)	216.8
Total cost of services provided	1,035.5	250.3	(201.1)	1,084.7
Earnings before amortization, interest, income taxes and non-controlling interest				
	116.2	88.1	9.4	213.7
Amortization	21.6	41.3	(3.0)	59.9
Interest	61.7	19.5	(67.1)	14.1
Income taxes	22.7	–	0.7	23.4
Non-controlling interest	(0.4)	–	–	(0.4)
Net earnings	10.6	27.3	78.8	116.7
Capital additions	40.7	96.8	2.3	139.8

(1) In December 2004, ENMAX recapitalized its subsidiaries through a combination of intercompany loan arrangements and dividends. The recapitalization was undertaken to match the regulator approved capital structure in ENMAX Power and to make the ENMAX Energy capital structure more consistent with the fair market value of its assets. To reflect this new structure, ENMAX has revised its segmented reporting. Beginning with the first quarter of 2005, external and intercompany interest revenue and expenses incurred by ENMAX Corporation is reported as part of ENMAX Corporate. Previously, these amounts were included within the operating segment results. Comparative periods have been restated to reflect these changes.

(2) Includes ENMAX Corporate and intersegment eliminations. Intersegment transactions are recognized on the basis of prevailing market or regulated rates.

(3) Included in electricity costs is \$10.2 million pertaining to the amortization of PPAs.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31 (Restated – note 3)	ENMAX Energy		ENMAX Power		ENMAX Corporate ⁽¹⁾		Consolidated totals	
	2004	2003	2004	2003	2004	2003	2004	2003
<i>(millions of Canadian dollars)</i>								
Revenue								
Sales of electricity and natural gas	1,020.1	1,052.2	–	–	(193.7)	(207.2)	826.4	845.0
Transmission and distribution revenue	–	–	266.6	277.0	–	–	266.6	277.0
Contractual services and other	38.6	35.6	70.7	80.0	(9.2)	(11.4)	100.1	104.2
Total revenue	1,058.7	1,087.8	337.3	357.0	(202.9)	(218.6)	1,193.1	1,226.2
Cost of services provided								
Electricity and natural gas costs ⁽²⁾	517.1	487.5	–	–	0.1	–	517.2	487.5
Grid charges	266.7	309.0	55.6	37.8	(195.7)	(208.2)	126.6	138.6
Local access fees	–	–	68.5	68.2	–	–	68.5	68.2
Operations, maintenance and administration	96.0	111.7	121.2	120.7	(8.9)	(2.0)	208.3	230.4
Total cost of services provided	879.8	908.2	245.3	226.7	(204.5)	(210.2)	920.6	924.7
Earnings before amortization, interest, income taxes and non-controlling interest								
	178.9	179.6	92.0	130.3	1.6	(8.4)	272.5	301.5
Amortization	17.4	23.5	39.0	43.2	(2.3)	(4.2)	54.1	62.5
Interest	7.1	3.7	15.2	17.5	(8.3)	(8.3)	14.0	12.9
Income taxes	50.8	51.9	–	–	1.4	1.2	52.2	53.1
Net earnings	103.6	100.5	37.8	69.6	10.8	2.9	152.2	173.0
Capital additions	6.9	52.8	98.4	91.9	7.7	38.8	113.0	183.5

(1) Includes ENMAX Corporate and intersegment eliminations. Intersegment transactions are recognized on the basis of prevailing market or regulated rates.

(2) Included in electricity costs is \$9.6 million (2003 – \$10.1 million) pertaining to the amortization of PPAs.

Total assets:

As at December 31	2005	2004
<i>(millions of Canadian dollars)</i>		
ENMAX Energy	839.6	698.3
ENMAX Power	708.9	659.1
Corporate and eliminations	237.6	373.0
	1,786.1	1,730.4

15. INTEREST

Interest expense is comprised of the following:

Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			
Interest on long-term debt	15.8	15.4	13.6
Short-term interest and other financing charges	0.6	0.9	0.9
Less: allowance for funds used during construction	(2.3)	(2.3)	(1.6)
	14.1	14.0	12.9

16. INCOME TAXES

Provision for income taxes

Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			
Current	30.5	38.3	6.7
Future	(7.1)	13.9	46.4
	23.4	52.2	53.1

Reconciliation of income tax expense

Years ended December 31	2005	2004	2003
<i>(millions of Canadian dollars)</i>			
Earnings before income taxes	139.7	204.4	226.1
Income not subject to taxes	(64.7)	(59.7)	(108.3)
	75.0	144.7	117.8
Federal and provincial tax rate	33.62%	33.87%	36.75%
Expected income tax expense	25.2	49.0	43.3
Non-deductible expenses	(0.3)	2.9	0.1
Large Corporations Tax	0.1	–	0.4
Adjustment to future tax asset for enacted changes in rates and other estimate revisions	(1.6)	0.4	9.2
Other	–	(0.1)	0.1
Actual income tax expense	23.4	52.2	53.1

Future income tax asset

The tax effects of temporary differences that give rise to significant portions of the Corporation's future income tax asset and future income tax liability are presented below:

As at December 31	2005	2004
<i>(millions of Canadian dollars)</i>		
Future income tax asset:		
Power purchase arrangements ⁽¹⁾	161.2	155.8
Cumulative eligible capital	14.6	15.2
Derivative financial instruments	4.7	2.6
	180.5	173.6
Future income tax liability:		
Property, plant and equipment – differences in net book value and undepreciated capital cost	4.0	2.1
Cumulative eligible capital	0.4	–
Other	4.2	–
	8.6	2.1
Net future income tax asset	171.9	171.5

(1) Under the payments in lieu of tax regulation, certain assets of the Corporation were deemed to be disposed of and reacquired at fair market value for tax purposes on December 31, 2000. This resulted in tax values in excess of book value for these assets.

17. FINANCIAL INSTRUMENTS

Hedging activities

The Corporation is fully exposed to price fluctuations in the market in which its sales are made. To manage this exposure, the Corporation acquired energy through the auction of PPAs for the output of coal-fired generating plants (see Note 9).

To manage price, volume and PPA unit outage risks, the Corporation utilizes a number of approaches, including energy commodity price swaps and real-time import or export of electricity. The Corporation runs a 24-hour-a-day, seven-day-a-week trading operation to manage dispatch of the PPA plants and hourly trading activities to manage short-term volume fluctuations. The Corporation manages the counterparty credit risk associated with these hedging activities through the use of aggregate exposure limits and contract limits for each counterparty.

All hedges are documented at inception, including information such as the hedging relationship, the risk management objective and strategy, the method for assessing effectiveness and the method of accounting for the hedging relationship. Financial instruments that do not qualify for hedge accounting are recognized on the balance sheet and measured at fair value, with changes in fair value recognized currently in income. For the year ended December 31, 2005, the impact of financial instruments that do not qualify for hedge accounting is a charge to net earnings of \$6.4 million (2004 – \$7.5 million; 2003 – nil), which is included in electricity and natural gas costs in the consolidated statement of earnings.

Fair value of off-balance sheet contracts-for-differences

Years ended December 31	2005	2004
	Notional quantity	Notional quantity
Electricity sales	3.3 million MWh	1.6 million MWh
Natural gas sales	0.2 million Gj	7.6 million Gj
Electricity purchases	0.6 million MWh	3.3 million MWh
Natural gas purchases	0.9 million Gj	1.8 million Gj

The fair value of the Corporation's contracts-for-differences is determined by estimating the amounts that would have to be received or paid to counterparties to terminate the contracts at December 31, 2005 and 2004.

Notional quantities are not recorded in the financial statements because these amounts are not exchanged by the Company and its counterparties and are not a measure of the Company's exposure. Notional amounts are used only as the basis for calculating payments for certain derivatives.

18. COMMITMENTS AND CONTINGENCIES

Property, plant and equipment

At December 31, 2005, the Corporation's commitment to major capital projects is \$106.8 million (2004 – nil).

Power Purchase Arrangements and Agreements

In return for the output from PPAs and other power purchase agreements, the Corporation is obligated to make estimated average monthly payments based on normal operating conditions of \$19.8 million for 2006 (2005 – \$20.1 million), adjusted for inflation, other than in the event of a forced outage.

Regulatory

The Corporation, along with other electrical distribution utilities in the province of Alberta, is subject to regulatory reviews and decisions. The impact of the reviews and decisions is reflected in the consolidated financial statements when the amount can be reasonably estimated.

On January 13, 2006, the Alberta Energy and Utilities Board (EUB) provided initial decisions regarding ENMAX Power's 2005 and 2006 Distribution Tariffs and ENMAX Energy's 2005 and 2006 Regulated Rate Tariff for electricity customers in Calgary.

The overall impact of these decisions is a charge to 2005 consolidated net earnings of \$5.0 million, reflected as a reduction in distribution revenue of \$5.7 million, an increase in sales of electricity of \$0.1 million and a reduction in amortization expense of \$0.6 million.

Legal claims

In the normal course of business, the Corporation is named as a defendant in lawsuits related to various matters. The Corporation believes the outcome of these lawsuits will not have a material impact on the Corporation.