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Attachment 9

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ENMAX

ENMAX 2013 FINANCIAL REVIEW

CAUTION TO READER

This document contains statements about future events and financial and operating results of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) that are forward-looking. By their nature, forward-looking statements require the corporation to make assumptions and are subject to inherent risks and uncertainties. There is significant risk that predictions and other forward-looking statements will not prove to be accurate. Readers are cautioned not to place undue reliance on forward-looking statements as a number of factors could cause actual future results, conditions, actions or events to differ materially from financial and operating targets, expectations, estimates or intentions expressed in the forward-looking statements.

When used in this Financial Report, the words “may”, “would”, “could”, “will”, “intend”, “plan”, “anticipate”, “believe”, “seek”, “propose”, “estimate”, “expect” and similar expressions, as they relate to the Corporation or an affiliate of the Corporation, are intended to identify forward-looking statements. Such statements reflect the Corporation’s current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation’s actual results, performance or achievements to vary from those described in this Financial Report. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward looking statements prove incorrect, actual results may vary materially from those described in this Financial Report. Intended, planned, anticipated, believed, estimated or expected and other forward-looking statements included in this Financial Report herein should not be unduly relied upon. These statements speak only as of the date of this Financial Report. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law, and reserves the right to change, at any time at its sole discretion, the practice of updating annual targets and guidance. Targets for 2014 are described in the Outlook Section of the Management’s Discussion and Analysis (MD&A).

Factors that could cause actual results to differ materially include, but are not limited to:

- competitive factors and pricing pressures, including electricity supply and demand in the Alberta power market and fluctuations in the pricing of natural gas in the North American market;
- the availability of our generation assets to produce power;
- regulatory developments as they relate to transmission and distribution rate-making and the impact of deregulation in the industry;
- human resources, including possible labour disruptions;
- financing and debt requirements, including ability to carry out refinancing activities;
- tax matters, including acceleration or deferral of required cash payments, realization of timing differences and potential reassessments by tax authorities;
- litigation and legal matters;
- business continuity events (including man-made and natural threats);
- economic growth and fluctuations as they relate to the natural resource-based Alberta economy;
- change in customers’ wants and needs due to evolving technologies and a movement; and
- other risk factors discussed herein and listed from time to time in ENMAX’s and other public disclosure documents.

For further information, see the MD&A Section; Risk Management and Uncertainties.

BECAUSE SETTING A SOLID FOUNDATION FOR FUTURE VALUE CREATION IS KEY

OVERVIEW

TO OUR STAKEHOLDERS

Throughout 2013, we remained focused on executing our financial strategy—maintaining a strong financial position and an investment grade credit rating to provide a solid foundation for current and future growth. 2013 highlights include:

- We earned a net income of $352.5 million further strengthening our balance sheet;
- We paid $67.5 million in dividends to The City of Calgary, the highest dividend pay-out since ENMAX began operations in 1998;
- We invested $502.3 million in capital projects in the Calgary area including $190.3 million invested in the transmission and distribution system and $285.6 million invested in generating facilities with $244.9 million invested in the Shepard Energy Centre (Shepard);
- We sold ENMAX Envision Inc. (Envision) and 50 per cent of Shepard facility, netting $808.4 million in proceeds that were used to repay debt and will be redeployed into our growth opportunities;
- We retired $250.0 million in debt, ahead of its scheduled payment in 2014;

Our 2013 performance was higher than earning levels in recent years' primarily as a result of the sale of ENMAX's fibre optics business. This sale, along with the transaction with Capital Power LP for the joint ownership in Shepard, allowed us to fund ongoing strategic capital investment and an early repayment of debt. We faced significant market challenges over the year including low power prices and a major outage at the Keephills 1 generating facility from which we receive output under a Power Purchase Arrangement (PPA). Even with these challenges, we delivered $173.4 million in net earnings from continuing operations.

The near-term outlook for Alberta power prices continues to be soft with new capacity coming on line, namely wind and gas-fired units. Our 2014 targets recognize the challenges we expect in the electricity industry with variability in electricity prices and lower average wholesale and realized prices than those seen in 2013. This downward pressure on prices together with the expiry at the end of 2013 of our capacity ownership of Battle River units #3 and #4 under a PPA are the primary contributors to forecasted lower electricity margins in 2014. However, increasing demand for electricity and the retirement of the older coal-fired facilities in the later part of the decade are expected to lead to higher power prices and new build opportunities, making Alberta an attractive market in which to invest. ENMAX is positioned to take advantage of this market in order to secure stable supply of electricity for its customers.

We hope that you find our financial review informative.

Gianna Manes

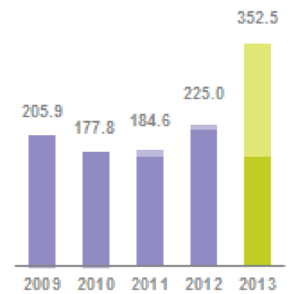
Gianna Manes

President and Chief Executive Officer

David Halford

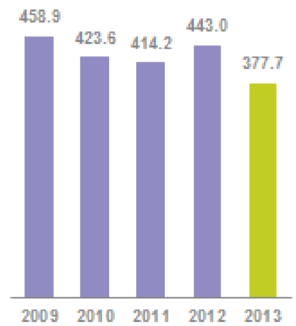
Executive Vice President, Finance and Planning,
Chief Financial Officer and Chief Risk Officer

NET EARNINGS
($ millions)



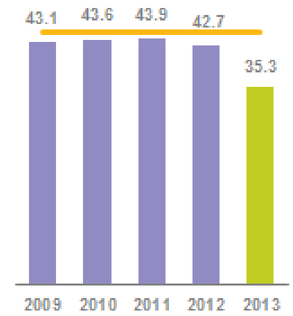
Discontinued operations
Continuing operations

EBIDTA[1]
($ millions)



(1) Non-GAAP financial measure. See discussion that follows in the Management's Discussion & Analysis (MD&A).

DEBT TO TOTAL CAPITALIZATION [1] (%)



Target maximum of 45%

(1) Long-term debt to total capitalization is equal to total long-term debt, including current portions, divided by the sum of long-term debt and shareholder's equity.

OVERALL HIGHLIGHTS

(millions of dollars, except where otherwise noted)	2013	2012
Revenue	3,364.1	3,160.1
Operating margin [1]	753.4	676.3
Net earnings	352.5	225.0
Earnings before interest, income taxes and depreciation (EBITDA) [1]	377.7	443.0
Earnings before interest and income taxes (EBIT) [1]	204.5	264.2
Cash flow from operations [1]	204.7	558.2
Total assets	4,565.5	4,819.9
Return on assets [2]	12.9%	8.7%
Return on equity (ROE) [3]	14.7%	10.5%
Total recordable injury frequency	0.90	0.43
Capital expenditures	502.3	646.7
Electricity sold to customers *(Gigawatt hours [GWh])*	20,889	21,399
Employees *(#)* [4]	1,846	1,809

(1) Non-Canadian Generally Accepted Accounting Principles (GAAP) financial measure. See discussion that follows in the MD&A.
(2) Return on assets is equal to net earnings, including gain on sale, before after-tax interest charges for the year divided by average total assets (adjusted for capital assets under construction and current liabilities) for the year.
(3) ROE is equal to net earnings, including gain on sale, for the year divided by average shareholder's equity for the year.
(4) Employees count is total employees. 2012 figure has been restated to reflect sale of Envision.

SEGMENT HIGHLIGHTS

ENMAX POWER HIGHLIGHTS

(millions of dollars, except where otherwise noted)	2013	2012
Regulated Business		
Revenue	633.7	647.7
Total assets	1,515.4	1,338.3
Capital expenditures	198.5	160.8
Rate base (1)	1,104.1	1,017.3
EBIT (2)	74.6	61.2
System average interruption duration index (SAIDI) (3)	0.43	0.39
System average interruption frequency index (SAIFI) (4)	0.76	0.66
Energy delivered *(GWh)*	9,473	9,440
Electricity sold to customers through regulated rate option (RRO) *(GWh)*	1,719	1,890
RRO customers *(#)* (5)	199,500	217,300
Competitive Construction Business		
Revenue	71.4	108.4
EBIT (2)	6.8	12.5

(1) Rate base is based on preliminary information. Regulatory true-ups and adjustments could be required in 2014 related to 2013. Transmission accounts for $248.5 million and Distributions is $855.6 million of the total rate base.
(2) Non-GAAP financial measure. See discussion that follows in the MD&A.
(3) SAIDI equals the total duration of a sustained interruption per average customer during a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.
(4) SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.
(5) RRO customers serviced as at December 31.

ENMAX ENERGY HIGHLIGHTS

(millions of dollars, except where otherwise noted)	2013	2012
Competitive Retail and Generation Business		
Revenue	3,031.1	2,829.4
Total assets	2,881.8	3,410.8
Capital expenditures	285.6	263.1
EBIT (1)	116.8	186.1
Number of metered customers (in Calgary)	458,822	448,349
Number of metered customers (throughout Alberta)	871,000	836,000
Electricity sold to customers *(GWh)*	19,170	19,509
Customer satisfaction (2)	82%	79%
Generation volume *(GWh)*	12,230	12,164

(1) Non-GAAP financial measure. See discussion that follows in the MD&A.
(2) Monthly weighted average of customers rating their interaction with ENMAX Encompass "Very Satisfied" per the customer interaction survey process with Service Quality Management.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

This MD&A, dated March 5, 2014, is a review of the results of operations of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) for the year ended December 31, 2013, compared with the same period in 2012, and of the Corporation's financial condition and future prospects. This discussion contains forward-looking information that is qualified by reference to and should be read in light of the caution to reader previously mentioned.

ENMAX's consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The Corporation has chosen to defer the adoption of International Financial Reporting Standards (IFRS) as permitted by the Accounting Standards Board (AcSB).

The Consolidated Financial Statements and MD&A were reviewed by ENMAX's Audit and Finance Committee and approved by ENMAX's Board of Directors (the Board). All amounts are in Canadian dollars unless otherwise specified.

The Corporation reports on certain non-GAAP financial measures such as operating margin and funds from operations that are used by management to evaluate performance of business units and segments. Because non-GAAP financial measures do not have a standardized meaning, the Corporation has defined and reconciled them with their nearest GAAP measure. For the reader's reference, the definition, calculation and reconciliation of consolidated non-GAAP financial measures is provided in the non-GAAP Financial Measures section.

CONTENTS

OUR BUSINESS

OVERVIEW AND STRATEGY

ENMAX is a wholly-owned subsidiary of The City of Calgary (The City), headquartered in Calgary, Alberta, Canada. We strive to be a leader in Alberta's (Province) power industry and endeavour to improve Albertans' quality of life by making, moving and marketing power in a safe, reliable and responsible manner. ENMAX and its predecessors have a proud history of providing Albertans with electricity for over 100 years and continue to explore ways to improve our province's electricity system and provide progressive solutions for our customers.

Our core operations include the competitive generation and sale of electricity across Alberta through ENMAX Energy and the regulated transmission and distribution of electricity in the city through ENMAX Power:

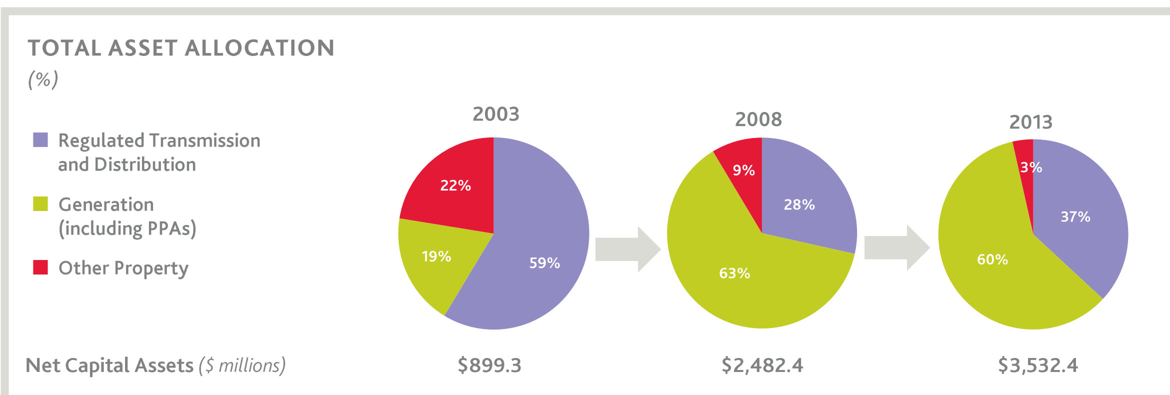
- ENMAX Energy is Alberta's leading competitive electricity retailer. In addition to electricity, ENMAX Energy provides natural gas, renewable energy and value-added services to residential, commercial and industrial customers throughout Alberta. It is also involved with the generation of electricity in Alberta and controls its physical electricity supply through Power Purchase Arrangements (PPAs) and owned generation capacity. It purchases natural gas on the wholesale market with terms and conditions to meet the sales commitments of its retail marketing operations and for the operational requirements of its natural gas-fired generating facilities. Risk management processes and systems are in place to carefully monitor and manage price and commodity risks inherent in the business.
- ENMAX Power owns and operates electricity transmission and distribution assets in the Calgary service area. In addition, it has the legislated responsibility to provide electricity for customers who elect to stay with the Regulated Rate Option (RRO). RRO is the default rate established by regulation and automatically provided to all eligible customers who have not entered into a contract with a competitive electricity retailer. ENMAX Power also has a competitive business that provides engineering, procurement, construction and maintenance services. ENMAX Power's objective is to maintain the high reliability of its transmission and distribution system while meeting Calgary's growing infrastructure needs.

While continuing to keep safety and reliability top of mind, we build our regulated business by investing in the growing transmission and distribution needs of the city. With this organic growth, the size of the regulated business's asset base will significantly increase in the future. Within the ENMAX Energy segment, we will invest in new generation assets to meet the growth of the demand in the province and to replace dispatchable generation capacity that will be lost with the expiration of our PPAs at the end of 2020. ENMAX will maintain its long history of relatively stable earnings and dividends through a retail portfolio of fixed-price electricity contracted sales. Flexibility provided by our growing natural gas assets will allow us to capture market opportunities. A strong focus on customers and stakeholders, process efficiencies, cost controls, and capital discipline supports this overall strategy.

We confirm and set corporate initiatives each year to advance our strategies. The objectives and initiatives embedded in our strategy are as follows:

Strategy	Mechanisms
Create a strong foundation for future growth	• Advancing a strong safety culture • Developing employees for strong execution today and into the future • Providing excellent customer service • Effectively managing costs and delivering strong outcomes • Advancing technology and system solutions to support business needs
Enhance our position as a strong Alberta power generator and retail market leader	• Completing Shepard Energy Centre (Shepard) on budget by first quarter 2015 • Build, acquire or contract new generation sources to replace expiring PPAs • Working with customers to identify and fulfill needs through a variety of attractive energy products • Ensuring strong availability of our generation supply • Supporting commercialization of renewable energy options
Operate and grow a highly reliable electricity infrastructure in Calgary	• Investing in transmission and distribution infrastructure • Maintaining high reliability • Achieving acceptable rates of return through constructive regulatory outcomes

An overall corporate portfolio is created by operating both ENMAX Power and ENMAX Energy. Key to our strategy is balancing this portfolio as we and the Alberta market grow and evolve.



ALBERTA'S REGULATED INDUSTRY

ENMAX Power operates and maintains the distribution and transmission system in Calgary. In a utility environment, it is more efficient to have a single provider in each service area, as it is expensive to build and maintain distribution and transmission networks. This makes the transmission and distribution systems a natural monopoly, which remains regulated in Alberta's restructured electricity system. Utility companies providing transmission services in the province own, operate, build and maintain the system of high-voltage power lines and other electrical equipment that move power from generators to towns, cities and large industrial customers. Distribution systems move electric energy from the high voltage transmission system to individual customers' homes and workplaces. Distribution power lines and facilities operate at 25 kilovolts or less. Most Albertans receive electricity from such distribution lines.

ENMAX Power's rates are determined through regulatory proceedings with the Alberta Utilities Commission (AUC). Beginning in 2007, the rates charged by ENMAX Power for wires services were set by formula as Formula-Based Rates (FBR) replaced traditional cost-of-service methodology. FBR, which was similar to mechanisms in other jurisdictions, had the following design objectives:

- Encourage more efficient operation;
- Safeguard reliability and service quality through performance standards;
- Provide time to develop and execute multi-year tactical strategies with a longer planning horizon; and
- Reduce the number, length, cost and complexity of regulatory hearings.

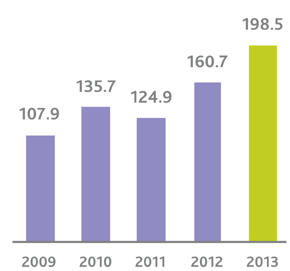
Over time, areas for improvement in the FBR mechanism became more apparent. The methodology did not fully account for higher than normal capital investment in distribution and transmission (no adjustment to rates for most of the capital spending), which resulted in a declining Return on Equity (ROE) during the FBR term. Additional FBR methodology challenges include:

- staff represents about half of operating costs - collective bargaining, staff additions for growth and Alberta's labour market make it difficult to control costs to inflation less an efficiency factor; and
- load growth acts to increase revenues; however, incremental operating costs to serve the load growth and the inability to adjust rates to account for growth driven capital investment (which increases interest and depreciation costs), partially offset this positive impact;

These issues made it challenging to maintain financial performance. Measured over the whole of the FBR term, ENMAX Power has not achieved the AUC approved generic ROE. Under cost of service regulation, the opportunity and risk of higher (or lower) earnings are lower than under performance based rates (PBR). Going forward, the distribution business will continue to use an FBR-type model of PBR to set tariffs with a new three to five-year term starting in 2014. The formula is expected to allow for some capital recovery during the term of the formula. As per an AUC decision and consistent with other companies with transmission assets, beginning in 2014 our transmission business will revert to a cost of service methodology with two-year terms as experience has shown the transmission business with its large, lumpy capital expenditures and single customer (the Alberta Electric System Operator (AESO)) is not amenable to formula rate setting mechanisms.

ENMAX POWER CAPITAL ADDITIONS

(Capital additiions net of contributions in aid of construction)



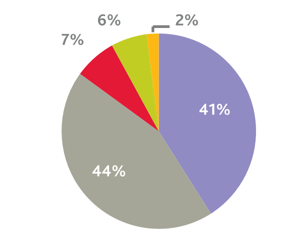
Calgary is growing and expected to continue to grow for the foreseeable future. This provides us with significant organic growth, leading to capital investment in our service territory. Projected capital expenditures will significantly increase rate base. Given the expected change to the rate-setting, the total capital expenditure profile and asset base growth is expected to provide increasing stable regulated earnings.

ALBERTA'S COMPETITIVE ELECTRICITY MARKET

The primary drivers of Alberta's electricity market are economic growth, expected coal plant retirements, changes in environmental regulations, government actions and market participant plans. Coal has been the primary fuel in the electricity market for 50 years; however, existing plants are aging and some are nearing end of life.

Under federal greenhouse gas (GHG) legislation, coal–fired plants must shutdown at the end of their life, calculated at 45-50 years, unless they can meet strict emission standards. Retrofitting to meet these standards is expensive and could be cost prohibitive. The current retirement schedule would change if equivalency agreements, under which Alberta legislation would replace the federal legislation, allow Alberta to achieve equivalent environmental outcome without adhering to the coal retirement schedule contemplated in the current GHG regulation.

ALBERTA INSTALLED CAPACITY BY FUEL SOURCE
(%)

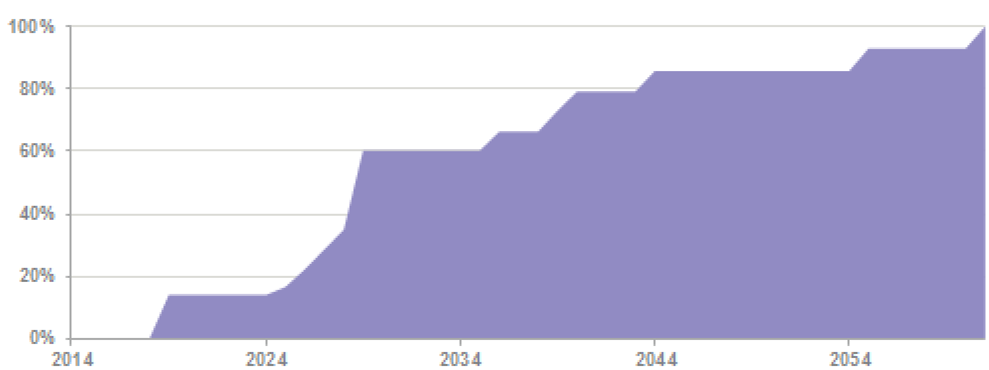


Source: AESO and CIBC World Markets

The retirement of coal assets is a critical factor influencing Alberta's electricity market over the next 20 years. Coal plants generate over half Alberta's electricity providing much of the base load. The timing and volume of these retirements determine the need for new generation. By 2030, about 60 per cent of the current coal supply is expected to retire, creating a step-change in Alberta's generation composition.

The retirement schedule removes almost 3,800 Megawatt (MW) of coal supply in the next 17 years. For comparison, about 1,450 MW of generation retired in the last 15 years (600 MW was coal-fired). Due to a number of factors, including the availability of natural gas in the Alberta market, expectations are that natural gas generation will be the fuel of choice to replace coal generation.

MANDATED COAL RETIREMENTS
(% of Market Production)



Source: CIBC World Markets

In the competitive Alberta market, changes to demand and supply factors have a direct impact on the market price of electricity, which is a significant factor in a number of areas of our business. Prices are set based on current spot prices, average monthly prices and future expected market prices. In 2013, the average flat pool price was $80.19 per megawatt hour (MWh), an increase from the $64.32 per MWh average in 2012. ENMAX Energy utilizes the fixed-price retail sales market to reduce its exposure to spot price volatility.

Critical factors that can impact electricity prices are:

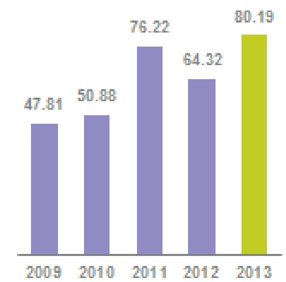
- Demand growth: Key element in the timing for new generation builds, and growth is sufficient in most scenarios to require material, new generation build.
- Supply reduction: Significant coal retirements following approximately 50-year legislated plant life with future new supply to be largely natural gas generation.
- Unplanned supply disruptions.
- Natural gas prices: Influence electricity prices as significant amounts of Alberta's current, and future, generation will be natural gas.

The Alberta electricity market price during peak demand periods is often influenced by the price of natural gas. The natural gas market saw average prices increase from $2.27 per gigajoule (GJ) in the 12 months ended December 31, 2012, to $3.01 per GJ for the same period in 2013.

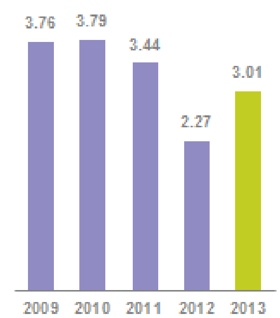
For natural gas-fired facilities, the spark spread is defined as the difference between the market price of electricity and the marginal cost of production. Profits and all other costs are collected from the spark spread. The term spark spread has come into common usage to describe the relative gross margin available in given electricity markets. Based upon an eight GJ per MWh heat rate combined cycle gas turbine, the average spark spread in Alberta has increased to $56 in 2013 from $46 in 2012 due to higher average gas prices.

ENMAX Energy does not have significant exposure to short-term market coal prices for the coal facilities under PPAs as the fuel and input costs for electricity generated at coal-fired facilities are calculated using a pre-determined formula based on Statistics Canada indexes. These include, but are not limited to, the cost of labour, mining machinery and other mining related expenses.

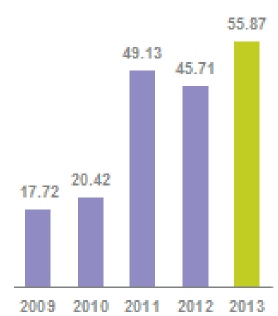
AVERAGE FLAT POOL PRICE
($/MWh)



AVERAGE NATURAL GAS PRICE
($/GJ)



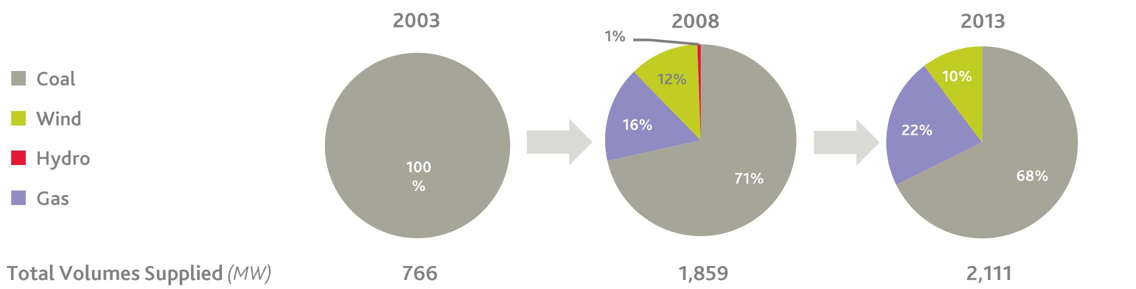
AVERAGE WHOLESALE MARKET SPARK SPREAD
($/MWH)



ENMAX's generation portfolio has evolved from 2003 and will continue to evolve with Shepard and the maturing of our PPAs. In 2003 the ENMAX supply portfolio reflected reliance on our PPAs at the time. Our 2013 portfolio represents our investment in wind and natural gas-fired generation facilities since 2003. The supply portfolio will continue to shift from coal to natural gas-fired generation in 2014 and 2015 as our capacity ownership in our PPAs reduces and Shepard is commissioned.

ENMAX GENERATION SUPPLY VOLUMES

(% MW Supplied)



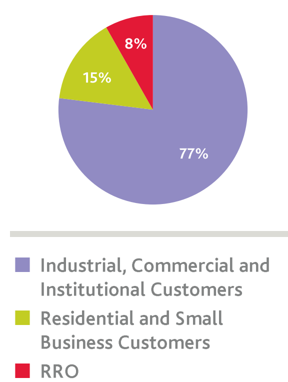
Independent market evaluators consider Alberta's market structure competitive and supportive of growth and rank it second in North America for customer choice and switching. Commercial and industrial customers dominate electricity consumption representing almost 80 per cent of total demand in the province.

ENMAX serves the full customer spectrum of residential customers to large industrial facilities. This wide customer reach allows us to adjust our approach to products and offerings and customer segments to optimize our overall supply-demand portfolio. The retail portfolio provides three value-adds:

- margin uplift above wholesale market prices;
- term liquidity beyond that available in Alberta's wholesale market; and
- ancillary profitability through index electricity products, natural gas fixed and index options, and other offerings.

RETAIL SALES PORTFOLIO

(% of total volume in MWh)



OVERALL FINANCIAL PERFORMANCE

SELECTED CONSOLIDATED FINANCIAL INFORMATION

(millions of dollars, unless otherwise noted)	2013	2012
Total revenue	3,364.1	3,160.1
Operating margin (1) (excluding unusual items)	753.4	676.3
EBIT (1)	204.5	264.2
EBITDA (1)	377.7	443.0
Net earnings from continuing operations	173.4	215.6
Net earnings	352.5	225.0
Funds generated from operations (1)	359.7	387.0
Cash provided by operating activities	204.7	558.2
Total assets	4,565.5	4,819.9
Long-term debt	1,439.0	1,609.5

(1) Non-GAAP financial measure. See discussion that follows in Non-GAAP Financial Measures section.

Results of operations are not necessarily indicative of future performance due to fluctuating commodity prices, the performance and retirement of existing generation facilities, and the addition of new generation facilities. Further details on specific operations can be found in the Business Segment Results section of this report.

SIGNIFICANT TRANSACTIONS IN 2013

SHEPARD ENERGY CENTRE JOINT VENTURE

On December 5, 2012, we entered into a two-part purchase and sale arrangement with Capital Power LP (CPLP), for CPLP to purchase a 50 per cent ownership interest in ENMAX Energy's 800 MW Shepard facility. Under the terms of the arrangement, on February 28, 2013, CPLP acquired a 25 per cent interest in the facility and on September 30, 2013 acquired the remaining 25 per cent interest. Through a 20-year Energy Services Agreement (ESA), ENMAX Energy will contract to purchase 300 MW of CPLP's Shepard output for the first three years of the ESA term and 200 MW for the remaining 17 years of the ESA term. Both parties hold their ownership interests in an unincorporated joint venture with agreement to build, own and operate the facility under a Joint Venture Agreement (JVA). Under the JVA, ENMAX Energy will continue to provide construction management services to the parties, has been appointed as the operator for the provision of operating and maintenance services, and has been appointed as joint venture manager for the provision of accounting and settlement services. An affiliate of CPLP has been appointed as the real-time operator to dispatch each party's electricity entitlement under the AESO rules. A management committee has been established to manage and govern the joint venture.

ENVISION SALE

On April 8, 2013, we entered into an agreement for the sale of a subsidiary, Envision, for $221.9 million net of adjustments. Envision is involved in high-speed data communications providing large bandwidth solutions to businesses. The sale transaction closed on April 30, 2013, and resulted in a gain on sale of $175.9 million. The results of operations of Envision to April 30, 2013 and the gain on sale were included in discontinued operations.

UNUSUAL ITEMS INCLUDED IN 2013 RESULTS

KEEPHILLS OUTAGE

On March 5, 2013, the Keephills Unit 1 generator was removed from service by its operator, TransAlta Corporation (TransAlta). Keephills Unit 1 provides ENMAX Energy with approximately 340 MW of electricity through a PPA. On March 26, 2013, TransAlta claimed force majeure under the Keephills PPA. Under a force majeure, we are not compensated for the outage by the owner for the duration of the outage but are relieved from paying certain capacity charges to the plant owner for the duration of the event. The Keephills Unit 1 generator returned to service on October 5, 2013. We are in a dispute resolution process with TransAlta in accordance with the terms of the PPA. For the year ended December 31, 2013, the Keephills outage impact was $127.5 million. Resolution of this dispute did not occur during 2013 and any recoveries pursuant to that dispute will be recognized when the dispute is resolved.

CALGARY AND AREA FLOODS

In June 2013, southern Alberta experienced significant flooding. In coordination with the Calgary Emergency Management Agency and government agencies, ENMAX Power disconnected and subsequently restored power to affected customers to ensure the safety of citizens. The disconnection and restoring of power minimized damage to ENMAX Power infrastructure and minimized the impact on citizens and damage to business property. For the year ended December 31, 2013, our response to the flood resulted in operational costs of $4.7 million and capitalized costs of $4.9 million (both before recoveries). In late 2013, insurers approved an interim payment that recovered $0.9 million of our 2013 flood related operational costs and $1.4 million of our 2013 flood related capital costs. In 2014, we will continue to file claims for reimbursement from our insurance providers on the operational and capitalized costs incurred in 2013.

CAPITALIZATION OF COSTS METHODOLOGY

Effective January 1, 2013, ENMAX Power implemented an AUC approved change in the methodology for capitalizing costs. This change reduced the amount of operations, maintenance, and administration expense (OM&A) that could be capitalized to projects, and therefore reduced amounts that could be recovered in future rates, instead allowing for this OM&A to be collected through current rates. The change increases transmission and distribution revenues and also increases OM&A expenses. For the year ended December 31, 2013, the impact to EBIT was a decrease $0.2 million.

In the following discussion, the term “Normalized” refers to the removal of the above noted unusual items from comparative margin and expense discussions. Normalized measures are a non-GAAP financial measure.

FINANCIAL RESULTS

EBIT FOR THE YEAR ENDED DECEMBER 31, 2013, COMPARED WITH THE SAME PERIOD IN 2012

(millions of dollars)

EBIT for the year ended December 31, 2012	264.2
Unusual items included in 2013 results:	
Keephills outage	(127.5)
Calgary and area floods	(3.8)
Capitalization of costs methodology	(0.2)
Increased margins attributable to:	
Electricity, excluding Keephills outage	27.2
Natural gas	6.6
Transmission and distribution	29.5
Contractual services and other	13.8
Decreased (increased) expenses:	
OM&A	(14.6)
Foreign exchange	13.0
Amortization	(3.7)
EBIT for the year ended December 31, 2013	204.5

Normalized electricity margins (electricity margins excluding the Keephills outage) for the year ended December 31, 2013, increased $27.2 million to $444.2 million from $417.0 million in the year ended December 31, 2012. The increased margins in the current year were driven primarily by better realized prices on forward contracts, increased sales volumes and prices on fixed price contracts, and a favourable outcome on a dispute concerning GHG emissions for 2009-2011. Higher revenues on ancillary services and higher market prices also contributed to the increase in margins over the prior year. These favourable items were partially offset by planned and unplanned plant outages and higher fuel costs associated with PPAs.

Natural gas margins for the year ended December 31, 2013, increased $6.6 million to $25.0 million from $18.4 million for 2012. This increase is primarily due to higher realized sales prices and higher volumes sold. This favourable impact was partially offset by the higher cost of natural gas supply.

For the year ended December 31, 2013, normalized transmission and distribution margins (excluding the capitalization of costs methodology change) increased $29.5 million to $228.4 million from the $198.9 million recorded in the same period in 2012. The increased margin in the year ended December 31, 2013 is due primarily to an increase in approved rates. Lower system access service costs for use of the provincial transmission grid also contributed to the increased margins.

For the year ended December 31, 2013, contractual services and other sources margin increased $13.8 million to $55.8 million from $42.0 million recorded in 2012. The increase is mainly due to the recognition of cost recoveries associated with ENMAX's joint venture with CPLP.

Normalized OM&A (OM&A excluding the flood costs and capitalization of costs methodology change) for the year ended December 31, 2013, increased $14.6 million to $255.9 million from $241.3 million in 2012. The increase for the year was largely due to an increase in staff costs and operating and maintenance costs related to Calgary Energy Centre's (CEC) successfully executed 45-day maintenance outage.

For the year ended December 31, 2013, a net foreign exchange gain of $6.6 million was recognized compared to a loss of $6.4 million in the same period of 2012. Foreign exchange gains or losses are primarily a result of the net realized and unrealized gains and losses on equipment purchase and service agreements denominated in foreign currencies and related hedges.

Amortization expense for the year ended December 31, 2013, increased $3.7 million to $168.1 million from $164.4 million for the same period in 2012. The increased charges were primarily the result of a net change in assets placed into service.

OTHER NET EARNINGS ITEMS

For the year ended December 31, 2013, interest expense decreased $7.1 million to $33.1 million from $40.2 million for the same period in 2012. The decrease was primarily due to an increase in the capitalization of interest related to capital projects.

Current and future income tax costs for the year ended December 31, 2013, decreased $10.4 million to a recovery of $2.0 million from an expense of $8.4 million for the same period in 2012. The decrease in income tax was primarily due to lower income in taxable entities.

Earnings from discontinued operations for the year ended December 31, 2013, decreased $6.2 million to $3.2 million from $9.4 million in the prior year. Earnings from discontinued operations relate to the Envision business unit which was sold April 30, 2013.

OTHER COMPREHENSIVE INCOME (OCI)

Other comprehensive income (OCI) illustrates earnings under the assumption of full income recognition of gains and losses on the market value of securities and derivatives otherwise treated as hedges of future period revenues and expenses. We use derivatives to hedge electricity, natural gas, interest rate and foreign exchange exposures. For the year ended December 31, 2013, OCI totalled gains of $13.3 million compared with gains of $49.2 million for the same period in 2012. OCI for the year ended December 31, 2013 primarily reflects the favourable fair value changes in derivative electricity positions and settlement of electricity and gas positions.

BUSINESS SEGMENT RESULTS

EBIT

(millions of dollars)	2013	2012
ENMAX Energy	116.8	186.1
ENMAX Power	81.4	73.7
Corporate & intersegment eliminations	6.3	4.4
EBIT	204.5	264.2

ENMAX ENERGY

STRATEGY

ENMAX Energy, which includes various legal entities and divisions, operates in Alberta's competitive energy market providing electricity, natural gas and renewable energy products to residential, commercial and industrial customers. In addition, it provides customer care, energy management, and district heating.

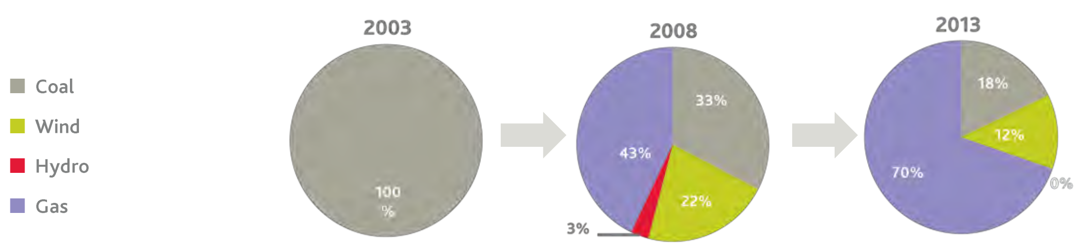
Our core strategy for ENMAX Energy is to grow the business across the province of Alberta. We supply energy through our own wind and natural gas-fired generation facilities and balance our energy portfolio needs through management of the wholesale PPAs at Battle River and Keephills, and through the purchase and sale of electricity and natural gas into and from the Alberta market. ENMAX Energy provides customers with competitive energy products and services with a focus on longer-term fixed or indexed contracts. This focus allows us to link the cost of supply to longer term demand contracts, which results in relatively stable margins even during times of volatile wholesale prices.

BUSINESS UPDATE

As discussed in the Overall Financial Performance section of this MD&A, ENMAX Energy was impacted in 2013 by the Shepard joint venture, Envision sale, Keephills outage, and flooding in the Calgary area.

ENMAX Energy's generation asset investment has evolved from 2003 and will continue to evolve with our investments into natural gas-fired power generation facilities and expiration of our PPAs. In 2003 the ENMAX Energy supply portfolio reflected our PPAs at the time. Our 2013 portfolio represents our investments into natural gas-fired generation facilities and wind.

GENERATION ASSET INVESTMENT
(%)



Net Capital Assets *($ million)*	$169.6	$1,560.8	$2,074.5

ENMAX Energy sees strong potential in the role natural gas will play in power generation and reducing the GHG emissions from generating facilities in the coming years. Key to this strategy is the development of the 800 MW Shepard facility located within the Calgary city limits.

Approximately 89 per cent of the overall Shepard project work was complete at December 31, 2013 and approximately $1,204 million of the $1,365 million project budget has been incurred at December 31, 2013. The project has surpassed three million hours of construction invested as of December 31, 2013, and on-site safety performance has exceeded our expectations. The project is on schedule with commissioning activities commencing in 2014 and full operations expected in early 2015.

In addition to our Shepard project, we have signed a Letter of Intent with CPLP to pursue JVAs to develop, construct, own and operate a natural gas-fired facility west of Edmonton with a generation capacity of up to 1,050 MW. The proposed facility, Genesee 4 and 5, would be built on a site near CPLP's existing Genesee facility and would utilize the latest high efficiency gas turbine technology. If we execute a JVA with CPLP it would be similar to our Shepard JVA with CPLP; however, in this case, CPLP would lead the construction of the project and be the operator of the facility. Construction of the proposed facility would be expected to be complete between 2018 and 2020, when additional generation is required to meet the growing demand in Alberta and to replace coal-fired generation set to retire.

Our Downtown District Energy Centre (DDEC), located in Calgary, was impacted by the flooding in June. As a result, we incurred $1.3M of restoration work to the facility with a majority of this spend recovered through insurance proceeds. Through the efforts of our employees, the plant was able to remain fully operational, providing heating services to DDEC customers during and after the flood. In 2013 DDEC secured its first condominium contract in the East Village along with the Historic Simmons Building. The Alberta Trade Centre, in the beltline, was also added as a customer. The City added Green Building Feature incentives to the new Downtown Planning District, which includes significant incentives for developers preparing to connect to DDEC.

ENMAX ENERGY'S FLEET OF GENERATION

Facility	Ownership	Capacity Ownership Interest (MW) 2013	2014	Fuel
Keephills PPA	100%	**766** (1)	766 (1)	Coal
Battle River PPA	100%	**663** (1)	368 (1) (3)	Coal
CEC	100%	**320**	320	Gas
Crossfield Energy Centre (Crossfield)	100%	**144**	144	Gas
Taber Wind Farm (Taber)	100%	**81**	81	Wind
McBride Lake Wind Farm (McBride)	50%	**75** (2)	75 (2)	Wind
Kettles Hill Wind Farm (Kettles)	100%	**62**	62	Wind
		2,111	1,816	

(1) Refers to facility PPA Capacity.
(2) ENMAX has a 50 per cent joint venture ownership interest in McBride and also obtains the other 50 per cent output through a tolling agreement with the other joint venture partner.
(3) As of January 1, 2014, ENMAX capacity ownership represents Battle River Unit 5. Unit 3 and 4 reverted back to facility owner.

During 2013 ENMAX Energy produced or had exclusive access to 2,111 MW of electricity generation to supply customer demand. On January 1, 2014 ENMAX capacity ownership in Battle River PPA was reduced, in accordance with the terms of the PPA, from 663MW of capacity ownership to 368 MW, representing our 100 per cent interest in the output of Battle River unit #5. Capacity ownership of Battle River unit #3 and #4 reverted back to the facility owner at the end of 2013.

The remaining power and all natural gas required to meet ENMAX Energy's consumer electricity and natural gas demand is acquired through the competitive wholesale power and natural gas markets. During times when ENMAX Energy has excess generation capacity, energy is sold to the market.

ENMAX Energy is the preferred electricity retailer for many industrial, commercial and institutional customers across Alberta. This includes federal and provincial government facilities, school districts, health care facilities, large industrial customers, and commercial enterprises across a variety of industries. Customers of all sizes continue to choose ENMAX Energy for its high-touch, consultative service model and flexible, competitively priced energy products. We continue to inform and empower Albertans to explore competitive rate options through EasyMax® and to help businesses manage their power needs by providing competitive and customized energy products. ENMAX Energy provides customers with creative and competitive alternative energy products and services. The Home Solar program introduced in 2011 continues as an option for customers. This program was developed for Albertans looking for a competitive solution for incorporating renewable energy into their homes.

As a wholesale market participant, PPA buyer and competitive retailer, ENMAX Energy is subject to the rules and regulations of the competitive electricity market, including codes of conduct (which establish, among other things, limits on the sharing of information between the regulated and competitive business units within ENMAX). As with other market participants, our compliance with these rules and regulations is subject to scrutiny by the Market Surveillance Administrator (MSA).

KEY BUSINESS STATISTICS	2013	2012
Market heat rate – flat average *(GJ/MWh)*	26.64	28.37
Average wholesale market spark spread *($/MWh)* (1)	$55.87	$45.71
Average flat pool price *($/MWh)*	$80.19	$64.32
Average natural gas price *($/GJ)*	$3.01	$2.27
Generation volume *(Gigawatt hours [GWh])*	12,230	12,164
Electricity sold *(GWh)*	19,170	19,509
Natural gas sold *(terajoules [TJ])*	50,807	49,536

(1) Assuming an average combined cycle gas turbine heat rate of 8 GJ per MWh.

In 2013 we experienced an increase in average wholesale market spread and average flat pool price from 2012 levels. This increase is attributed to the impact of the Keephills outage on supply in the market and the impact of higher natural gas prices.

ENMAX Energy sold, under contract, 19,170 GWh of electricity to customers in the current year compared with 19,509 GWh in the same period of 2012. This slight decrease is due primarily to a decrease in commercial and industrial customer volumes partially offset by an expanding customer base in residential.

ENMAX Energy's natural gas customers purchased 50,807 TJ of natural gas in 2013, compared with 49,536 TJ in the same period in 2012. The increase in volume sold in the year is due primarily to volume growth from an increased customer base in the residential market.

FINANCIAL RESULTS

ENMAX Energy recorded EBIT of $116.8 million for the year ended December 31, 2013, compared with $186.1 million in the prior year.

EBIT FOR THE YEAR ENDED DECEMBER 31, 2013, COMPARED WITH THE SAME PERIOD IN 2012

(millions of dollars)

EBIT for the year ended December 31, 2012	186.1
Unusual item included in 2013 results:	
Keephills outage	(127.5)
Calgary and area flood	(0.1)
Increased margins attributable to:	
Electricity, excluding Keephills outage	28.2
Natural gas	7.3
Contractual services and other	9.2
Decreased (increased) expenses:	
OM&A	(0.4)
Foreign exchange	13.0
Amortization	1.0
EBIT for the year ended December 31, 2013	**116.8**

The Keephills outage resulted in an unfavourable impact for 2013 of $127.5 million. See page 12 of this report for further details.

Flood response had a minimal net financial impact on ENMAX Energy EBIT as insurance proceeds largely offset expense incurred, resulting in a decrease of $0.1 million.

Normalized electricity margins for the year ended December 31, 2013, increased $28.2 million to $439.3 million compared with the $411.1 million recorded in 2012. The increased margins in 2013 were driven primarily by better realized prices on forward contracts, increased sales volumes and price on fixed price contracts, and a favourable outcome on a dispute concerning GHG for 2009-2011. Higher revenues on ancillary services and higher market prices also contributed to the increase in margin over the prior year. These favourable items were partially offset by planned and unplanned plant outages and higher fuel costs associated with PPAs.

Natural gas margins increased $7.3 million to $25.7 million for the year ended December 31, 2013, compared with $18.4 million last year. This increase in the year ended December 31, 2013, is primarily due to higher realized sales prices and higher volumes sold. This favourable impact was partially offset by the higher cost of natural gas supply.

Contractual services margin and other revenues increased $9.2 million in the year ended December 31, 2013, to $24.7 million compared to $15.5 million in 2012. The increase in margins was mainly due to recognizing the recovery of costs associated with ENMAX's joint venture with CPLP.

OM&A expenses increased $0.4 million for the year ended December 31, 2013, to $145.3 million, compared with $144.9 million in 2012. The increase in OM&A for the year ended December 31, 2013, was driven primarily by an increase in operating and maintenance costs related to the CEC 45 day planned outage in May 2013 and an increase in staff costs. These increases were partially offset by a decrease in expenses related to long-term service agreements (LTSAs) and advertising.

For the year ended December 31, 2013, a net foreign exchange gain of $6.6 million was recognized compared to a loss of $6.4 million in 2012. Foreign exchange gains are primarily a result of the realized and unrealized gains on equipment purchase and service agreements denominated in foreign currencies and associated hedges.

Amortization expense for the year ended December 31, 2013, decreased $1.0 million compared to 2012. The decreased charge was the net result of increased amortization in the prior year on specific assets offset by an increase in assets placed into service in the year ended December 31, 2013.

ENMAX POWER

STRATEGY

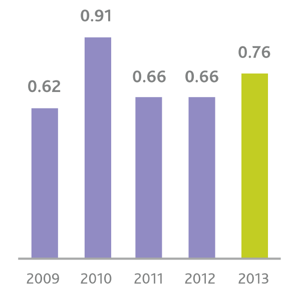
Providing safe, reliable delivery of electricity, to Calgarians is ENMAX Power's highest priority.

For duration and frequency of power service interruptions, we are a top quartile performer amongst other Canadian utilities. System average interruption duration index (SAIDI) is an industry measurement to express the average duration of a customer outage. The average outage duration time in 2013 was 0.43 hours. System average interruption frequency index (SAIFI) is an industry measurement to express how often an outage may be experienced by a customer. The average number of interruptions in 2013 was less than one or 0.76.

SYSTEM AVERAGE INTERRUPTION DURATION INDEX

We continue to invest in our electric transmission and distribution system infrastructure to meet Calgary's growing needs. This includes expansion of the distribution system, reinforcement of the transmission system and replacement of aging infrastructure in both systems. Distribution projects include investments in system infrastructure to accommodate residential, commercial and industrial growth, as well as the replacement and modification of existing assets required to meet industry safety and reliability standards. Transmission projects include capacity upgrades to existing substations, new substations and transmission lines to deliver reliable electricity to meet the growing demand within Calgary.

SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX



BUSINESS UPDATE

As discussed in the Overall Financial Performance section of this MD&A, ENMAX Power was impacted by the Calgary-area flood and the change in capitalization of costs methodology.

On December 31, 2013 FBR expired. FBR was a rate setting mechanism in place since 2007 by which our distribution access service (DAS or distribution rates) and the transmission revenue requirement (the amount ENMAX Power forecasts it requires to operate and maintain facilities, cover capital expenses and provide an opportunity to earn a reasonable return) were determined annually by formula.

We filed the 2014-2015 Transmission General Tariff Application and 2014 Phase I Distribution Tariff Application with the AUC on July 25, 2013. In this application, we are seeking approval of transmission revenue requirements of $68.8 million and $77.4 million for 2014 and 2015 respectively, and a distribution revenue requirement of $315.0 million for 2014. A subsequent application will be filed in 2014 which will contain our proposal to replace FBR for future years for distribution.

As a result of unanticipated accelerated growth in transmission capital expenditures and capital additions during the FBR period, the approved FBR formula for transmission operations did not provide a reasonable opportunity to earn a fair ROE. Using certain “re-opener” provisions approved by the AUC in Decision 2009-035, in 2012 we filed an application seeking approval to recover approximately $16.0 million. A decision on this application is expected in the second quarter of 2014.

The government mandated rate freeze that began March 8, 2012 was lifted January 29, 2013. Following the lifting of the rate freeze, we received AUC Decisions on the 2011, 2012 and 2013 FBR Annual Rate and Technical (ART) Reports in October 2013, resulting in an additional $5.3 million in distribution revenue and $8.0 million in transmission revenue.

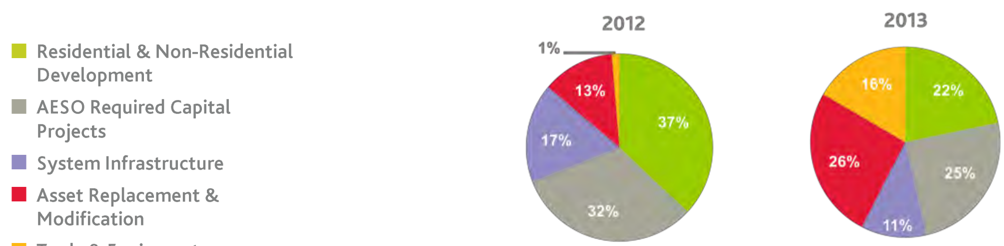
We are the RRO provider for “eligible customers” as defined in the RRO Regulation within our service area. There is an outstanding non-energy proceeding with the AUC which, when approved, will set the final monthly administration charge for the years 2012-2014.

We are currently participating in an AUC-initiated generic proceeding for Alberta RRO providers regarding energy price setting plans (EPSPs). The current EPSPs expire June 30, 2014. The new plans approved by the AUC in this proceeding will set the methodology for calculating the monthly energy rates to be charged to RRO customers for the period after July 1, 2014.

In 2013 we continued to execute our capital plans to meet the increasing need for electricity in Calgary while continuing to offer the same level of reliable service. Transmission and distribution capital projects that either commenced or continued in 2013 resulted in $51.0 million incurred for residential and non-residential development and $26.1 million for system infrastructure. Capital work was also completed on asset replacement and modification projects with $60.5 million being incurred during the year, to meet industry standards and safety codes and for automation of elements of the distribution network. In addition, investments of $57.8 million were made in AESO-required capital projects and $39.0 million was invested in information technology, facilities and other tools required for the business.

We successfully energized three key new substations in 2013. Substation 54 was energized in April 2013 to provide electricity to the new Calgary South Health Campus. Substation 65 was energized in September 2013 and is key to providing reliable transmission service to the growing areas of south Calgary. Substation 25, which is key for the Shepard facility, was also energized in September 2013.

ENMAX POWER CAPITAL ADDITIONS



Gross Capital Additions *($ million)*	2012	2013
	$209.7	$234.4

Contributions of $35.9 million were received from customers during the year, resulting in a net investment by ENMAX Power of $198.5 million.

In 2013, our underground residential development (URD) group supported construction of 2,007 residential lots in Calgary, the lowest number in the past five years. The lower URD lot counts are related to developers being unable to complete their annual construction schedules because of delays in obtaining required approval of their storm water management plans due to the flooding of city departments. Developers have pushed a number of their 2013 developments into 2014.

KEY BUSINESS STATISTICS	2013	2012
Electricity sold through the RRO *(GWh)*	1,719	1,890
Distribution volumes *(GWh)*	9,473	9,440
Regulated ROE—Distribution (1)	8.0%	10.2%
Regulated ROE—Transmission (1)	5.9%	0.5%
Rate base—Distribution(1)	855.6	797.9
Rate base—Transmission(1)	248.5	219.4
Local access fees collected on behalf of The City *($ millions)*	129.3	148.3
SAIDI (2)	0.43	0.39
SAIFI (3)	0.76	0.66

(1) These numbers are based on preliminary information. Regulatory true-ups and adjustments could be required in 2014 relating to 2013.
(2) SAIDI equals the total duration of a sustained interruption per average customer during a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.
(3) SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.

ENMAX Power's regulatory return is determined using a deemed capital structure of 59 per cent debt to 41 per cent equity for the distribution business and 63 per cent debt to 37 per cent equity in the transmission business. ENMAX Power's target ROE under the FBR framework is 8.75 per cent, and this level of return may either be exceeded or not met based on actual performance under FBR. Regulated ROE for distribution decreased in 2013, primarily due to reduced earnings. This resulted from higher pension contributions and deemed interest in 2013, offset by increased system access service (SAS) volume revenue and additional revenue recognized following the October 2013 AUC Decisions on the 2011, 2012 and 2013 FBR Annual Rate and Technical ("ART") Reports. Regulated ROE for transmission increased in 2013 as a result of higher earnings primarily due to the same October 2013 AUC decisions partially offset by higher pension contributions and deemed interest in 2013. As discussed, the transmission business has experienced low ROE levels and we have applied to the AUC for the ability to revisit the returns under the transmission rates. No provision for this possible recovery has been recognized in 2013. Rate base increased for transmission and distribution due to capital additions during the year.

RRO electricity volumes sold decreased to 1,719 GWh in the year ended December 31, 2013, compared with 1,890 GWh in 2012. Lower demand was seen as a result of customers switching from the RRO option to competitive options.

Total electricity delivered in the Calgary service area for the year was consistent with prior periods. Electricity volumes of 9,473 GWh were delivered in the year ended December 31, 2013, compared to 9,440 GWh in the same period of 2012. This modest increase was primarily due to an increase in per site consumption.

FINANCIAL RESULTS

ENMAX Power's financial results are driven by tariffs approved by the AUC for the regulated transmission, distribution and RRO businesses and by earnings from its competitive power services business. The regulated segment accounted for 88 per cent of ENMAX Power's total revenue in the year ended December 31, 2013, compared with 84 per cent in 2012.

ENMAX Power recorded EBIT of $81.4 million for the year ended December 31, 2013, compared with $73.7 million in the prior year.

EBIT FOR THE YEAR ENDED DECEMBER 31, 2013, COMPARED WITH THE SAME PERIOD IN 2012

(millions of dollars)

EBIT for the year ended December 31, 2012	73.7
Unusual item included in 2013 results:	
Calgary and area flood	(3.7)
Capitalization of costs methodology	(0.2)
Increased (decreased) margins attributable to:	
Electricity	(0.7)
Transmission and distribution	29.5
Contractual services and other	(4.9)
Increased expenses:	
OM&A	(8.8)
Amortization	(3.5)
EBIT for the year ended December 31, 2013	**81.4**

For the year ended December 31, 2013, our response to the flood resulted in a decrease to EBIT of $3.7 million. This value is comprised of incurred expenses of $4.2 million net of $0.5 million of insurance proceeds. We will be submitting further claims in 2014 with respect to this event.

The change in capitalization of costs methodology resulted in a decrease to EBIT for the year ended December 31, 2013, of $0.2 million. This impact is the net of a $12.8 million increase to revenues and $13.0 million increase to OM&A.

Electricity margins from RRO customers decreased $0.7 million to $6.2 million for 2013 compared with $6.9 million in 2012. This decreased margin was primarily the result of higher electricity costs and a decrease in sales volumes as more customers took advantage of competitive offers.

Normalized transmission and distribution margins consist of amounts charged for wire services net of electrical grid charges and local access fees. Normalized transmission and distribution margins increased $29.5 million to $228.4 million for the year ended December 31, 2013, compared with $198.9 million in 2012. The increase margin in the year ended December 31, 2013 is due primarily to an increase in approved rates. Lower system access service costs also contributed to the increased margins.

For the year ended December 31, 2013, margins for contractual services and other revenues decreased $4.9 million to $26.3 million compared with $31.2 million last year. The decrease in margins for the year ended December 31, 2013 was mainly due to a decrease in activity for URD in the second quarter of 2013. The decrease in activity is attributed to fewer residential lots constructed and delays in projects due to flooding experienced in Calgary in the second quarter.

Normalized OM&A expenses for the year ended December 31, 2013, totalled $118.8 million, compared with $110.0 million in 2012. The increase in OM&A costs for the year ended December 31, 2013, was driven primarily by higher staff costs to support increased capital projects, safety initiatives, and overtime and growth in ENMAX Power Services business.

Amortization for the year ended December 31, 2013, totalled $56.8 million compared with $53.3 million in 2012. The increase was the net result of amortization related to new assets put into service partially offset by a decrease in the asset base from older assets concluding their depreciable lives.

CORPORATE AND INTERSEGMENT ELIMINATIONS

ENMAX Corporate provides billing and customer care services, shared services and financing to ENMAX Power and ENMAX Energy. During the year ended December 31, 2013, EBIT for ENMAX Corporate increased slightly to $6.3 million, as compared with $4.4 million in the prior year. In 2013, the subsidiary ENMAX Encompass Inc. (Encompass) was moved to be reported within corporate and intersegment eliminations segment. Encompass provides billing and customer care services to residential and small commercial customers and had previously been reported under ENMAX Energy. Prior figures have been restated.

SELECTED QUARTERLY FINANCIAL DATA

	2013				2012			
(millions of dollars)	Fourth	Third	Second[2]	First	Fourth	Third	Second	First
Total revenue	882.6	790.0	859.4	832.1	869.3	797.3	658.4	835.1
Operating margin [1]	218.0	136.3	115.8	169.5	194.7	138.7	168.0	175.0
EBIT [1]	101.6	30.1	6.7	66.1	77.4	41.7	67.7	77.2
Net earnings from continuing operations	88.3	20.7	8.2	56.2	61.6	42.8	50.7	60.5
Net earnings	88.3	20.7	185.2	58.3	63.9	45.4	53.1	62.6

(1) Non-GAAP financial measure. See discussion that follows in the MD&A.
(2) The sale of Envision occurred in the second quarter of 2013.

Many variables must be considered regarding the seasonality of revenues, operating margin, EBIT and net earnings. Overall, the bulk of the business does not experience extreme cyclical activities that would allow identification of common variations quarter over quarter.

Electricity volumes sold and electricity volumes distributed to industrial and institutional customers are not significantly seasonal in nature. While customers can have seasonal requirements, the seasonal requirements of one customer base can be offset by another, resulting in relatively flat demand over the course of a year. Volumes are predominantly cyclical on a 24-hour period. Residential volumes sold and distributed peak in the winter, resulting in higher revenues during winter months. Volume requirements of commercial customers peak in the summer, with higher demand for air conditioning. This is offset by a lower demand in the residential market during the summer. Over longer periods of time, volumes can fluctuate with general economic activity and population growth. Unusual items/events have an impact on seasonal expectations. The Keephills outage negatively impacted the financial results of the second and third quarter of 2013.

Natural gas volumes and prices are correlated seasonally as a result of weather patterns. Natural gas consumption and prices will increase with extreme weather typically seen in the winter. As well, natural gas prices can rise in extreme hot weather in the summer as peak electricity demand results in increased gas-fired generation. Revenue levels tend to decline in the fall and spring due to these unfavourable trends in natural gas prices and volumes during those parts of the calendar year.

FOURTH QUARTER FINANCIAL RESULTS

EBIT FOR THE THREE MONTHS ENDED DECEMBER 31, 2013, COMPARED WITH THE SAME PERIOD IN 2012

(millions of dollars)

EBIT for the period ended December 31, 2012	77.4
Unusual item included in 2013 results:	
Outage at Keephills Unit 1	(2.4)
Flood response	0.1
Capitalization of costs methodology	2.0
Increased (decreased) margins attributable to:	
Electricity	(15.2)
Natural gas	1.5
Transmission and distribution	32.2
Contractual services and other	3.1
Decreased (increased) expenses:	
OM&A	(1.1)
Foreign exchange	5.0
Amortization	(1.0)
EBIT for the period ended December 31, 2013	**101.6**

In the fourth quarter of 2013, net earnings increased $24.4 to $88.3 million compared with $63.9 million in the same three month period in 2012. EBIT increased $24.2 million from $77.4 million to $101.6 million.

In the fourth quarter, normalized electricity margins (electricity margin excluding Keephills outage) were $109.8 million compared with $125.0 million in the same period in 2012. The $15.2 million decrease in margins were driven primarily by a decrease in realized prices on forward contracts and increased costs associated with PPAs, offset by higher revenues on ancillary services.

For the three months ended December 31, 2013, natural gas margins increased $1.5 million to $9.9 million from $8.4 million in the comparable period in 2012. This increase was due to increased sales volume and lower realized natural gas costs.

For the regulated business, normalized transmission and distribution margins (transmission and distribution margins excluding the change in capitalization of costs methodology) increased $32.2 million to $80.8 million compared to $48.6 million in the three months ended December 31, 2012. The increased margin in the three months ended December 31, 2013 is due primarily to a delay in receiving a rate decision from the AUC which resulted in the recognition of rates from previous quarters and years.

Contractual services margin and other revenue was $15.8 million in the fourth quarter of 2013 compared with $12.7 million in the fourth quarter of 2012. This increase was due primarily to an increase in project activity in the fourth quarter of 2013.

Normalized OM&A costs (OM&A costs excluding the change in capitalization of costs methodology and flood costs) increased $1.1 million to $74.3 million in the fourth quarter of 2013, compared with the costs of $73.2 million incurred in the fourth quarter of 2012. This increase was primarily due to an increase in staff costs, partially offset by a decrease in expenses related to LTSAs.

For the three months ended December 31, 2013, a net foreign exchange gain of $3.6 million was experienced as compared to a loss of $1.4 million in the same period of 2012. This was due primarily to gains on the foreign exchange positions related to the LTSAs.

Amortization costs increased $1.0 million to $43.7 million in the three months ended December 31, 2013, compared with $42.7 million in the same period in 2012. The slight increase was due to an increase in net capital additions during the year.

Interest costs amounted to $7.0 million in the fourth quarter of 2013 compared with $7.6 million in the same period in 2012. This decrease in interest costs reflects the net impact of a decrease in recoveries of interest during construction (IDC) and lower fourth quarter interest expense due to the repayment of a $250 million private debenture on September 30, 2013.

For the three months ended December 31, 2013, income tax expenses decreased to $6.3 million compared with $8.2 million in the same period in 2012. The decrease was mainly due to lower income in taxable entities.

Earnings from discontinued operations, net of tax, were nil in the fourth quarter of 2013, compared with earnings of $2.3 million in the same period in 2012. ENMAX Energy's Envision business line was sold on April 30, 2013 and there are no assets or business lines held for sale in the fourth quarter of 2013.

The Corporation invested $126.0 million in capital projects during the quarter including $29.6 million in transmission projects, $41.0 million in distribution projects, $43.3 million on generation facilities and $12.1 million on corporate information technology assets.

In the fourth quarter, the Corporation made $24.1 million of regularly scheduled repayments on its long-term debt. In addition, the final $16.9 million dividend installment was paid to The City, which resulted in payment in full of the 2013 declared dividend of $67.5 million.

NON-GAAP FINANCIAL MEASURES

The Corporation provides non-GAAP financial measures in the MD&A. These measures do not have any standard meaning prescribed by GAAP and may not be comparable to similar measures presented by other companies. The purpose of these financial measures and their reconciliation to GAAP financial measures are shown below. These non-GAAP measures are consistent with the measures used in the previous year, with the exception of removal of the unusual items in the operating margin measure.

OPERATING MARGIN

Year ended December 31 *(millions of dollars)*	2013	2012
Electricity margins	444.2	417.0
Natural gas margins	25.0	18.4
Transmission and distribution margins	228.4	198.9
Contractual services margins [1] and other revenue	55.8	42.0
Operating margin (non-GAAP financial measure), excluding unusual items	753.4	676.3
Deduct unusual item: Outage at Keephills Unit 1	127.5	–
Deduct unusual item: Flood response	3.8	–
Deduct unusual item: Capitalization of costs methodology	0.2	–
Deduct: OM&A, foreign exchange, amortization, interest and income taxes	448.5	460.7
Net earnings from continuing operations (GAAP financial measure)	173.4	215.6

(1) Contractual services margins include earnings from distributed generation; home services; meter reading and data management services for non-Calgary municipalities; water meter reading; pole and duct rentals; service locates; streetlight repairs; LRT monitoring; mapping record management; engineering, procurement, construction and maintenance services; utility trenching; construction and maintenance of LRT systems; self-retailing services; and billing services.

Operating margin is a useful measure of business performance, as changes in the market price of electricity and natural gas purchased for resale affect revenue and cost of sales equally. ENMAX Energy's strategy links the cost of supply to longer-term demand contracts, which results in relatively stable margins even during times of volatile wholesale prices and revenue levels. Therefore, operating margins better reflect profitability than revenue levels alone.

EBITDA

Year ended December 31 *(millions of dollars)*	2013	2012
Adjusted EBITDA (non-GAAP financial measure)	377.7	443.0
Deduct: EBITDA from discontinued operations	5.1	14.4
Standardized EBITDA (non-GAAP financial measure)	372.6	428.6
Deduct:		
Amortization	168.1	164.4
Interest	33.1	40.2
Income taxes	(2.0)	8.4
Net earnings from continuing operations (GAAP financial measure)	173.4	215.6

EBITDA is a useful measure of business performance, as it provides an indication of the cash flow results generated by primary business activities without consideration as to how those activities are financed and amortized or how the results are taxed in various business jurisdictions. EBITDA is also used to evaluate certain debt coverage ratios.

EBIT

Year ended December 31 *(millions of dollars)*	2013	2012
EBIT (non-GAAP financial measure)	204.5	264.2
Deduct:		
Interest	33.1	40.2
Income taxes	(2.0)	8.4
Net earnings from continuing operations (GAAP financial measure)	173.4	215.6

EBIT is a useful measure of business performance, as it provides an indication of the operating results generated by primary business activities, including the costs of amortization. It does not consider how those activities are financed or how the results are taxed in various business jurisdictions.

FUNDS GENERATED FROM OPERATIONS

Year ended December 31 *(millions of dollars)*	2013	2012
Funds generated from operations (non-GAAP financial measure)	359.7	387.0
Changes in non-cash working capital	(136.2)	111.9
Employee future benefits	(4.7)	7.0
Cash flow from continuing operations	218.8	505.9
Cash flow from assets held for sale	(14.1)	52.3
Cash provided by operating activities (GAAP financial measure)	204.7	558.2

Funds generated from operations are used as an additional metric of cash flow without regard to changes in our non-cash working capital.

TOTAL INTEREST COST

Year ended December 31 *(millions of dollars)*	2013	2012
Total interest cost (non-GAAP financial measure)	88.8	86.0
Ineffective portion of interest rate swaps	(1.9)	(1.3)
Capitalized interest	(57.9)	(50.3)
Other non-interest financing costs	4.1	5.8
Interest expense (GAAP financial measure)	33.1	40.2

Total interest cost is used in determining interest coverage ratios.

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

(millions of dollars, except % change)	December 31, 2013	December 31, 2012	$ Change	% Change	Explanation for Change
ASSETS					
Cash and cash equivalents	**80.6**	45.5	35.1	77%	Refer to Liquidity and Capital Resources section.
Income taxes [1] [2]	**96.9**	78.6	18.3	23%	Current year tax provisions.
Assets held for sale [1]	–	566.1	(566.1)	(100%)	All assets held for sale were sold by December 31, 2013.
Property, plant and equipment (PPE)	**3,022.6**	2,694.5	328.1	12%	Capital expenditures, net of retirements, dispositions and amortization.
PPAs	**369.5**	422.2	(52.7)	(12%)	Amortization of PPAs.
LIABILITIES AND SHAREHOLDER'S EQUITY					
Short-term debt	–	165.9	(165.9)	(100%)	Refer to Liquidity and Capital Resources section.
Accounts payable and accrued liabilities	**436.8**	612.6	(175.8)	(29%)	Timing of the payment of power pool invoices and lower capital accruals.
Other assets/liabilities [1] [2]	**13.9**	37.0	(23.1)	(62%)	Change in fair value of hedging instruments.
Long-term debt [2]	**1,439.0**	1,609.5	(170.5)	(11%)	Repayment of $250.0 million of private debentures, offset by acquisition of $140.6 million of Alberta Capital Finance Authority (ACFA) debt.

(1) Net asset and liability positions.
(2) Includes current and long-term amounts.

LIQUIDITY AND CAPITAL RESOURCES

SHARE CAPITAL

As at December 31, 2013, and 2012 (millions of dollars, except share amounts)	Number of Shares	Amount
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Issued on incorporation (one dollar)	1	–
Issued on transfer of net assets from Calgary Electric System (CES)	1	278.2
Issued on transfer of billing and customer care assets from The City in 2001	1	1.9
	3	**280.1**

CAPITALIZATION

December 31 *(millions of dollars)*	2013	2012
Long-term debt [1]	1,439.0	1,609.5
Shareholder's equity		
Share capital	280.1	280.1
Retained earnings	2,186.4	1,901.4
Accumulated other comprehensive loss	(6.3)	(19.6)
Total shareholder's equity	2,460.2	2,161.9
Total capitalization (long-term debt plus shareholder's equity)	3,899.2	3,771.4

(1) Includes the current portion of long-term debt of $63.7 million (December 31, 2012- $59.7 million). Maturity dates range from June 2014 to June 2038.

TOTAL LIQUIDITY AND CAPITAL RESERVES

December 31 *(millions of dollars)*	2013	2012
Committed and available bank credit facilities	1,150.0	1,150.0
Letters of credit issued:		
Power pool purchases	85.2	130.1
Energy trading	34.5	45.0
Regulatory commitments	105.9	107.9
Asset commitments	3.1	34.7
PPAs	75.2	67.3
	303.9	385.0
Commercial paper and overdraft	–	165.9
Remaining available bank facilities	846.1	599.1
Cash on hand	80.6	45.5
Total liquidity and capital reserves	926.7	644.6

The increase in total liquidity and capital reserves during the year ended December 31, 2013, is attributed primarily to a reduction in commercial paper and overdraft loans which were enabled by the receipt of proceeds from the sale of a 50 per cent interest in the Shepard facility and the sale of Envision. This increase was partially offset by the funding of AESO payments at year end which reduced accounts payable.

LONG-TERM DEBT

December 31 *(millions of dollars)*	2013	2012
Long-term debt [1] consisting of:		
ACFA debentures, with remaining terms of:		
Less than 5 years	34.0	47.0
5 – 10 years	122.4	135.4
11 – 15 years	14.4	7.9
16 – 20 years	187.1	138.3
21 – 25 years	557.6	499.3
Private debentures		
Series 1, remaining term of 5 years, bullet maturity on June 19, 2018	298.2	297.8
Series 2, repaid during the quarter	-	249.5
Non-recourse term financing (Kettles and CEC), remaining terms of 3.3 and 13.0 years, respectively	220.5	229.3
Promissory note, remaining term of 13.3 years	4.8	5.0
	1,439.0	1,609.5

(1) Includes current portion of long-term debt of $63.7 million (December 31, 2012- $59.7 million). Maturity dates range from June 2014 to June 2038.

CONTRACTUAL OBLIGATIONS THAT MAY IMPACT THE CORPORATION'S FINANCIAL CONDITION

As at December 31, 2013 *(millions of dollars)*	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Total debt [1]	1,439.0	63.7	138.9	417.2	819.2
Operating leases	52.3	8.1	12.2	9.0	23.0
Purchase obligations [2]	132.5	90.4	20.3	10.6	11.2
Asset retirement obligations	15.4	–	–	–	15.4
Other long-term obligations [3]	55.8	–	32.5	12.3	11.0
Total contractual obligations	**1,695.0**	**162.2**	**203.9**	**449.1**	**879.8**

(1) Total debt includes short-term debt and excludes interest payments.
(2) Purchase obligations means an agreement to purchase goods or services that is enforceable and legally binding on ENMAX that specifies all significant terms, including fixed or minimum quantities to be purchased; fixed, minimum, or variable price provisions; and the approximate timing of the transaction.
(3) Other long-term obligations means other long-term liabilities reflected on the Corporation's balance sheet.

CAPITAL STRATEGY

CREDIT METRICS

As at December 31	2013	2012
Long-term debt to total capitalization [1]	35.3%	42.7%
Debt to EBITDA [2]	2.6X	3.8X
EBITDA to total interest [3]	6.1X	4.9X

(1) As at year end, long-term debt (including current portion) to total capitalization is equal to long-term debt divided by total long-term debt plus shareholder's equity. If cash were netted against the debt, the ratio as at December 31, 2013, would be 33.3 per cent (December 31, 2012 – 41.5 per cent).
(2) Debt to EBITDA is equal to long-term debt (including current portion) divided by EBITDA for the last 12-month rolling period. If cash were netted against the debt, the ratio as at December 31, 2013, would be 2.5X (December 31, 2012 – 3.6X).
(3) EBITDA to total interest is equal to EBITDA for the last 12-month rolling period divided by total interest cost (non-GAAP financial measures) calculated on a 12-month rolling basis.

The business is funded with a view to maintaining a conservative capital structure in line with our strategy of maintaining a stable, investment grade credit rating. We have set long-term target ratios for long-term debt to total capitalization at a maximum of 45 per cent, a debt to EBITDA ratio at a maximum of 3.5 times and an EBITDA to total interest coverage ratio at five times or better. Very low electricity prices, asset outages, and high capital expenditures associated with significant construction projects or other factors could result in targets not being reached for short periods of time. Targets are managed using a long-term view and set at more conservative levels than actual debt covenants. Standard & Poor's has assigned ENMAX a BBB+ rating with a stable outlook. Dominion Bond Rating Services has assigned a credit rating of A (low). These ratings provide reasonable access to debt capital markets.

The principal financial covenant in our credit facilities is debt to capitalization. As at December 31, 2013, we are in compliance with all of the financial maintenance covenants in our debt agreements.

CASH PROVIDED BY OPERATING ACTIVITIES

Funds generated from operations for the year ended December 31, 2013, were $359.7 million, compared with $387.0 million in 2012. The decrease in funds generated was primarily due to lower cash generating earnings.

Cash provided by operating activities for the year ended December 31, 2013, was lower than the same period in the prior year at $204.7 million compared to $558.2 million in 2012. The decrease was driven by the reduction of accounts payables from December 31, 2012 (which was high due to timing of payments) and lower cash generating earnings in 2013.

INVESTING ACTIVITIES

Capital spending was $502.3 million in the year ended December 31, 2013, compared to $647.2 million in 2012 (includes $215.6 million of spend in assets held for sale). Capital projects for the year ended December 31, 2013 included $190.3 million related to investment in the transmission and distribution network in Calgary and surrounding area; $285.6 million in construction costs related to Calgary area generation projects; and $26.4 million related to other capital additions, including information technology development.

ENMAX realized $586.5 million of proceeds from the disposal of 50 per cent of the Shepard project and $221.9 million of proceeds on the sale of Envision.

FINANCING ACTIVITIES

On June 15, 2013, $140.6 million of debt was obtained from The City through arrangements with the Alberta Capital Finance Authority to fund ongoing investment relating to the regulated transmission and distribution network in Calgary and the surrounding area.

On September 30, 2013, a $250.0 million private debenture was repaid prior to its maturity date of April 8, 2014. A redemption premium of $4.9 million was incurred as a result of the early redemption of this debenture. Regularly scheduled long-term debt principal payments of $61.1 million were made during the year ended December 31, 2013, compared with $56.1 million in 2012.

At December 31, 2013, cash and cash equivalents amounted to $80.6 million compared with $45.5 million at December 31, 2012. At December 31, 2013, no commercial paper was outstanding, compared with $149.9 million at December 31, 2012, and there were no overdrafts on bank accounts, compared with $16.0 million at December 31, 2012.

On March 8, 2013, a dividend of $67.5 million was declared. All quarterly installments of this dividend were paid by the end of 2013. On March 5, 2014, a dividend of $60.0 million was declared, payable to The City in four quarterly installments. We have historically paid The City annual dividends of at least the higher of 30 per cent of the prior year's net earnings or $30 million. Dividends for a fiscal year are established in the first quarter of the same fiscal year. The payment and level of future dividends on the common shares will be affected by such factors as financial performance and liquidity requirements.

FUTURE ACCOUNTING CHANGES

On February 13, 2008, the AcSB confirmed the changeover from GAAP to IFRS, as issued by the IASB, would be effective for fiscal years beginning on or after January 1, 2011. The AcSB has issued amendments to this directive that presently allows entities that have activities subject to rate regulation to delay adoption of IFRS until January 1, 2015. As such, ENMAX will be required to adopt IFRS in reporting interim and annual consolidated financial statements, including comparative periods, beginning January 1, 2015. While IFRS uses a conceptual framework similar to GAAP, there will be differences in accounting policies.

With the initial decision to adopt IFRS in Canada, we executed on a conversion plan for the Corporation and have since maintained a state of readiness. Certain updates and activities will be required to prepare for the final adoption of IFRS in 2015.

AREA	DESCRIPTION OF CHANGE	STATUS AND SIGNIFICANT IMPACTS
Standards Update	A number of new standards and amendments to standards have been issued since we last prepared our transition plan.	These standards are being evaluated for their applicability and impact. We continue to monitor IASB activities and develop reporting requirements to meet new standards.
Opening Balance Sheet	Our opening balance sheet date is January 1, 2014.	Adjustments identified previously are being updated with current information.
Rate Regulated Activities	On January 30, 2014, the IASB issued the interim standard IFRS 14 Regulatory Deferral Accounts to address accounting for effects of rate regulation under IFRS.	This standard is being evaluated.
Systems	The original system solution is no longer valid given our move to a new project costing and fixed asset system on January 1, 2014.	The requirements of IFRS were built into the new project costing and fixed asset system. Testing and evaluation of this system, for use in IFRS reporting, is underway.
Internal Control over Financial Reporting (ICFR) and Disclosure Controls	Changes to our control environment cannot be finalized until IFRS standards and Corporation policies are finalized.	We continue to evaluate the impacts of IFRS changes on disclosure controls and ICFR. Open discussions continue with our external auditor about possible outcomes to new standards and impacts.
Financial Reporting Expertise	Internal resources are being utilized for conversion efforts.	Conversion status is provided to the Audit, Finance and Risk Committee on a quarterly basis. Training efforts will be reintroduced in 2014.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of our consolidated financial statements requires the use of estimates and assumptions. Accounting policies have been developed to ensure appropriate implementation and interpretation of accounting rules and complex situations are addressed using careful judgment and research. Adjustments to previous estimates that impact net income and could be material, are recorded in the period they become known.

The significant accounting policies adopted by our Company are described in Note 2 in the Notes to the Consolidated Financial Statements. ENMAX's critical accounting estimates are related to revenue recognition, allowance for doubtful accounts, amortization expense, asset impairment, asset retirement obligations, provisions for income taxes, employee future benefits, financial instruments and IDC. The estimates and assumptions made in these areas can be highly uncertain at the time the estimate or assumption is made. Different or changing estimates and assumptions could potentially have a material impact on ENMAX's financial position or results of operations. These critical estimates are described in the following discussion.

REVENUE RECOGNITION

The majority of our revenue is derived from the sale of electricity. The various systems and procedures used by third parties to provide load and settlement data to retailers across the province are required to completely and accurately capture all customer movement, load classification and consumption data. By regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until four months after the month in which such electricity was consumed. There are a number of variables in the calculation of these estimates and the underlying energy settlement processes within the Alberta electric systems and our Company are complex. These estimates are necessary since the regulatory environment in which we operate often requires amounts to be recorded at estimated values until finalization and adjustment pursuant to subsequent regulatory decisions, or other regulatory proceedings. Estimates for unbilled consumption averaged \$124.1 million (2012 – \$128.4 million) at the end of each month and adjustments of estimated revenues to actual billings averaged \$2.1 million (2012 – \$2.3 million), representing an average of two per cent of the estimates for 2013 and 2012. Reconciliation of settled volumes for 2013 will continue in 2014 based on the timing of receipt of settlement data. These estimates affect accrued electricity revenues and accrued electricity costs of ENMAX Energy Corporation.

ALLOWANCE FOR DOUBTFUL ACCOUNTS

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 accounts receivable, historical write offs, assessments of the collectability of amounts from individual customers and general economic conditions. Our allowance account averaged \$7.2 million (2012 – \$7.3 million), and at each internal reporting period was within the range of \$6.1 million to \$7.9 million (2012 – \$6.1 million to \$8.3 million). The estimate of the allowance affects ENMAX Energy Corporation's and ENMAX Power Corporation's accounts receivable and OM&A.

AMORTIZATION EXPENSE

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 life characteristics of common assets. The ranges of amortization assumptions used in measuring our amortization expense are outlined in Note 2 in the Notes to the Consolidated Financial Statements.

ASSET IMPAIRMENT

PPE makes up a significant portion of our total assets. The majority of those assets are involved in the generation of electricity. We consider several factors which could indicate an impairment of its assets including significant underperforming operating results, significant changes in the use of the asset and significant negative economic trends. When an indication of impairment is identified, we estimate the fair value of certain assets. Estimates of fair values for these assets are based on undiscounted cash flow techniques which rely on a number of assumptions such as the amount of future cash flows that will be generated from the asset, expected future prices for inputs and outputs and expected usage of the asset. An impairment loss, if justified, would be recorded as the excess of the carrying amount of the asset over its fair value.

ASSET RETIREMENT OBLIGATIONS

Measurement of the our asset retirement obligations involves the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required, discount rates, inflation rates and related future cash flows. Each individual asset requires a separate analysis of these methodology inputs and thus, quantification of the range of assumptions used would not be meaningful on a cumulative basis.

PROVISION FOR INCOME TAXES

Income taxes and amounts in lieu of income taxes are determined based upon estimates of our 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 more likely than not, a valuation allowance will be recorded and charged against income in the period that the allowance is created or revised.

EMPLOYEE FUTURE BENEFITS

We have a defined benefit (DB) pension plan and post-retirement benefits that are provided to certain employees. The cost of these benefits recognized in the financial statements are subject to estimates around many factors including, but not limited to, assumptions of future return on plan assets, retirement age, mortality rates, discount rates, future health care costs, salary escalation rates and claims experiences. The significant actuarial assumptions used in measuring our accrued benefit obligation and net benefit plan expense are outlined in Note 13 in the Notes to the Consolidated Financial Statements.

FINANCIAL INSTRUMENTS

The fair values of financial instruments are determined and classified into three categories, Level I, II and III. Level I financial instruments are based on quoted market prices and are therefore subject to little estimation and judgment. Level II financial instruments have fair values that are determined using inputs other than quoted market prices that are readily observable for the specific asset or liability. These fair values are subject to estimates around determining the observable source to be used and the use of similar inputs for instruments that are not regularly traded. Level III financial instruments have fair values that are determined using inputs that are not readily observable. These fair values are subject to estimates embedded in the valuation technique used.

Further discussion of the impact of estimates on the fair values of financial instruments can be found in Note 4 in the Notes to the Consolidated Financial Statements.

INTEREST DURING CONSTRUCTION (IDC)

IDC is capitalized on a monthly basis on qualifying assets by applying a borrowing rate to the carrying amount of the asset. Qualifying assets are those assets that take a substantial period of time to complete (greater than or equal to six months, or that are less than six months but would incur significant borrowing).

RISK MANAGEMENT AND UNCERTAINTIES

Our approach to risk management addresses risk exposures across all of the Corporation's business activities and risk types. We utilize an Enterprise Risk Management (ERM) program to identify, analyze, evaluate, treat and communicate the Corporation's risk exposures in a manner consistent with ENMAX's business objectives and risk tolerance.

Risk exposures are managed within levels approved by the Board and senior management and monitored by personnel in the business units, the risk management department and by the senior management team. At a management level, each accountability area is responsible for assessing its risk exposures and implementing risk treatment plans. Our risk management department coordinates an enterprise risk assessment process and provides risk reporting and related monitoring. Risk oversight is delivered through the Board and the Risk Management Committee (RMC) which consists of senior management members. Together, the RMC and Board oversee identified risk exposures and risk management programs, including the Enterprise Risk Management (ERM) program.

Our overall risk control environment includes:

- clearly articulated corporate values, principles of business ethics, and a code of conduct, which employees are required to review annually;
- published enterprise-wide policies in key risk areas such as delegation of authority;
- documented commodity trading and position limits;
- an internal audit function to test compliance with internal controls and policies;
- regular reporting of risk exposures and mitigations, including insurance programs, to the RMC and Board;
- the use of industry-accepted tools and methodologies for tracking risk exposures; and
- a Safety and Ethics HelpLine for employees to anonymously report suspected illegal or unethical behaviour without fear of retaliation if the employee does not feel comfortable reporting this information directly to his or her manager.

These risk management programs and governance structures are designed to manage and mitigate a number of risk factors affecting our business.

It is not possible to accurately quantify or assess the financial risk of many future events. As such, we use financial impact bands in quantifying its risks. Below are the bands used in the risk process:

Indicative Impact	Potential Financial Impact
Low	• 1 Yr Budget: < $5 million • 5 Yr Plan: < $25 million
Moderate-Low	• 1 Yr Budget: $5-10 million • 5 Yr Plan: $25-50 million
Moderate-High	• 1 Yr Budget: $10-20 million • 5 Yr Plan: $50-100 million
High	• 1 Yr Budget: >$20 million • 5 Yr Plan: >$100 million

The following discussion does not consider the result of any interrelationship among the factors and is hypothetical and not necessarily indicative of actual future results and should be used with caution. All risks described below are residual risks, meaning they are the remaining risk exposures after mitigations have been applied.

MARKET RISK

ENMAX has inherent risk in electricity and natural gas commodity positions arising from owned and controlled supply assets and demand obligations. We also purchase and sell these commodities in wholesale markets to manage such positions. While our business model is designed to achieve a balanced portfolio, in the near term, electricity and natural gas positions may experience periodic imbalances and result in exposures to price volatility from spot or short-term contract markets. In the longer term, where we have fewer fixed price retail contracts, there is greater exposure to market price risk.

ENMAX Energy utilizes numerous tools to forecast electricity consumption and generation, as well as the pattern of consumption and generation between peak and off-peak hours (load shape). It is not possible to hedge all positions every hour. As such, there is exposure to volume and load shape risk. ENMAX Energy may purchase blocks of electricity in advance of consumption in order to minimize exposure to extreme price fluctuations between off-peak and peak hours. We actively manage assets to match generation to consumption volumes and have peaking facilities that allow quick reaction to unexpected supply and demand factors. To oversee these risks, we have implemented an ERM program based on leading industry practices to analyze, control and report on commodity price risk exposures. This program includes risk metrics and associated limits, such as open commodity positions and Value at Risk, approved by the Board and senior management. Stress testing is performed regularly to provide additional information on the potential impact of extreme events on ENMAX Energy's portfolio. The ERM program is operated by a middle office controls group which is independent of the front office trading floor and the back office accounting and settlement group.

We have seen and could have future earnings variability with a moderate-low impact as it relates to the sustainability and diversification of our portfolio. Furthermore, a valuation modeling error could produce earnings variability which could also have a low impact. Overall commodity price levels have a potential earnings variability which could have a high financial impact. Low impact earnings variability could also be seen as a result of retail residential and small business and industrial, commercial and institutional customer demand volatility reducing retail margins or a decrease in renewal and acquisition rates.

ENMAX Energy uses derivative instruments, such as swaps and forwards, to manage exposure to commodity price risk. Financial gains and losses could be recognized as a result of volatility in the market values of these contracts. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts. The inability or failure to effectively hedge our energy portfolio and prevent financial losses from derivative instruments could adversely affect the business, results of operations, financial condition or prospects of the Corporation. Our hedging strategies control and mitigate these commodity price risks. Occasionally, hedging is ineffective as it is based upon predictions about future market conditions and may require a minimum level of market liquidity to actively manage positions. The sensitivity of commodity prices on financial derivatives is discussed in Note 4 of the Notes to the Consolidated Financial Statements.

ENMAX has foreign exchange rate exposures arising from certain procurement and energy commodity business activity. We hedge the majority of our foreign exchange risk exposures as such exposures arise. Such hedges may not be sufficient to cover foreign exchange exposure in the event of timing mismatches or extreme foreign exchange rate movements. The sensitivity around foreign exchange rate is discussed in Note 4 of the Notes to the Consolidated Financial Statements.

Changes in interest rates can impact borrowing costs and certain of the revenue streams from business activities. Substantially all of our long-term debt is currently either fixed-rate amortizing debt, fixed-rate bullet debt or variable debt with linked interest rate swap hedges. This structure effectively mitigates exposure to interest rate fluctuations in the near term. Short-term debt is generally variable rate and long-term debt will need to be replaced at maturity leading to longer term exposure. The sensitivity around interest rates is discussed in Note 4 of the Notes to the Consolidated Financial Statements.

Overall, market risk is considered high in the one year time frame.

OPERATIONAL RISK

ENMAX owns, controls or operates a number of electricity generation, transmission and distribution facilities. The operation of such facilities involves many risks, including public safety incidents; start-up risks; breakdown or failure of generation, transmission or distribution facilities or pipelines; use of new technology; dependence on a specific fuel source, including the transportation of fuel; impact of unusual or adverse weather conditions (including natural disasters); and performance below expected or contracted levels of output or efficiency. Natural resource operating facilities are subject to weather driven risks such as water and wind availability. There is risk of inadequate or failed internal processes, people and systems within the competitive and regulated businesses, shared services departments and certain outsource service organizations.

Breakdown or failure of a facility may prevent the facility from performing as expected under applicable agreements which, in certain situations, could result in termination of the agreements or incurring a liability for damages. Unanticipated transmission and distribution facility outages can cause interruptions in service. Unanticipated generation facility outages and de-rates can cause periodic imbalances in our electricity and natural gas positions. Weather conditions can materially affect the level of demand for electricity and natural gas, the prices for these commodities and the generation of electricity at certain facilities. In addition, our demand obligations may fluctuate based on commodity prices, season, day and time of use and specific customer requirements.

Events that could result from physical or cyber war, terrorism, civil unrest or vandalism may cause damage to ENMAX and its assets and impact our generation, transmission and distribution operations or administrative functions in unpredictable ways.

These operational risks may affect our ability to execute on our strategy in an effective and efficient manner, affect the quality of customer service and result in lost revenues and/or increased costs. These risks are actively managed using incentives, site planning, controls, safety, security and insurance programs in addition to a number of other measures. Certain critical areas within ENMAX have implemented security measures and emergency response plans. In addition, we have obtained property, business interruption and other insurance coverage to mitigate some of these risk exposures, although such programs and measures may not prevent or cover the occurrence of any or all of these events and the adverse effects they may generate.

Earnings could be affected by a regulated transmission blackout/brownout, failure of metering equipment, or loss of communication services. Fuel supply shortages, failure of third party services or infrastructure, human error, labour disruption, hazards to facilities and regulatory decisions could cause earnings variability. There has been and could be future exposure to moderate-high impact earnings variability due to a significant failure at a PPA plant (defined as a failure causing an outage of six months or longer) or variability due to the variation in the annual incentive payments to PPA operators. A low impact in earnings variability could also be seen as a result of the non-performance of contracted physical electricity or natural gas by counterparties. Overall the operational risk facing the organization is classified as high in the one-year time horizon.

ENVIRONMENTAL RISK

ENMAX is subject to regulation by federal, provincial and local authorities with regard to air, land and water quality and other environmental matters. The generation, transmission and distribution of electricity results in and requires disposal of certain hazardous materials which are subject to these laws and regulations. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for non-compliance, including fines, injunctive relief and other sanctions. New environmental laws and regulations affecting our operations may be adopted and new interpretations of existing laws and regulations could be invoked or become applicable, which may substantially increase environmental expenditures in the future. New facilities or modifications of existing facilities may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, denials of permit applications and conditions imposed in permits may materially affect the cost and timing of projects. Non-compliance with environmental laws and regulations or incurrence of new costs or liabilities could adversely affect the business, results of operations, financial condition or prospects of the Corporation. We have implemented various programs to manage environmental risk exposures, many of which focus on prevention of and preparedness for adverse events.

In 2007, the Government of Alberta passed the Climate Change and Emissions Management Act and Alberta's Specified Gas Emitters Regulation to address the regulation of GHG emissions from certain facilities located in the province. Effective July 1, 2007, facilities emitting more than 100,000 tonnes of GHG per year are required to reduce their emissions intensity from an emissions intensity baseline. The companies responsible for these facilities have been given a number of options to allow them to comply with this requirement, including making operational improvements to the facilities, buying eligible offsets to apply against their emissions and contributing to a fund established for the purpose of investing in technology to reduce GHG emissions in the province. We have taken steps to substantially mitigate these impacts, including acquiring qualified credits from both wind generation assets and purchases on the wholesale market. We continue to assess and monitor the implications these changes in legislation may have on our business.

The federal GHG regulations received Gazette II publication in September 2012. The Regulations resulted in the extension of coal-fired unit life, from the government's previously proposed hard limit of 45 years, to up to 50 years depending on the unit's commissioning date. In addition to the GHG regulation, Environment Canada is continuing to develop a National Air Quality Management System that could include Base Level Industrial Emissions Requirements (BLIERs) for existing coal-fired generation units that could set new limits for nitrogen oxide (NOx) and Sulfur oxide (SOx) emissions. Environment Canada has indicated that the original proposal, which would have made it necessary to perform costly retrofits on PPA assets is being rethought and Environment Canada is preparing to start fresh discussions on NOx and SOx limits. ENMAX has and continues to advocate that the combination of the federal GHG regulation and existing Alberta criteria air contaminant regulation will result in similar emissions reductions so that BLIERS does not need to be implemented in Alberta.

We mitigate our exposure to environmental regulations by building and acquiring new generation capacity emitting less GHGs; purchasing emission reductions offsets; investing in environmentally improved technologies in its supply from PPAs; and developing workplace conservation programs. Overall, moderate earnings variability exposure is possible if we fail to comply with our Environmental Management System

(EMS). Exposure to further moderate volatility is possible due to each of the following: potential of spills, releases and fire from hazardous materials, or as a result of GHG emissions policy changes.

REGULATORY RISK

We operate in competitive and regulated sectors of the electricity and natural gas industries and are subject to regulation by federal, provincial and municipal governmental regulatory and market authorities. Oversight of industry regulations is provided by the Alberta Department of Energy, AUC, MSA, AESO, National Energy Board, North American Electric Reliability Corporation, U.S. Federal Energy Regulatory Commission and other agencies.

Regulations and regulatory decisions affect our regulated business in a number of areas, including allowed rates of return; industry and rate structure; development and operation of transmission and distribution facilities; acquisition, disposal, depreciation and amortization of facilities; and recovery of certain operating costs. Our competitive and regulated businesses are subject to a number of specific regulations established to help ensure Alberta's wholesale and retail electricity and natural gas markets operate in a fair, efficient and openly competitive manner. ENMAX Power is a transmission and distribution system owner, and an electrical utility which is regulated by the AUC and is also subject to regulatory oversight for provision of the RRO. ENMAX Energy is an affiliated retailer of ENMAX Power and along with ENMAX Power, must comply with Code of Conduct regulation, which preserves a level playing field for all retailers, as well as general energy marketing regulations.

We cannot predict the future municipal, provincial or federal governments, or their policies that may impact the development of regulation over our business or the ultimate effect that any changes to the regulatory environment may have on our business. The regulatory process or specific decisions by a regulator may restrict our ability to grow earnings, recover costs or achieve a targeted ROE in certain parts of our competitive and regulated businesses, or cause delays in or impact business planning and transactions and increase costs. Non-compliance with laws or regulations or changes to the regulatory environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

We actively participate in the various regulatory processes that influence our business environment and operations. We actively monitor business activity that is subject to regulation and have implemented compliance programs to mitigate regulatory and political risk exposures. Exposure to financial impacts as they relate to changes to existing, as well as new or upcoming policies, protocols, standards, administrative orders or regulations exists. There is also potential exposure to financial impact in regards to regulatory decisions and matters related to generation operations. Overall exposure to regulatory risk is considered to be moderate in the one-year time frame.

HUMAN RESOURCES RISK

ENMAX is subject to workforce factors, including loss or retirement of key executives or other employees; availability of and ability to attract, develop and retain qualified personnel; collective bargaining agreements with union employees and performance of key suppliers and service providers. A number of personnel with highly specialized knowledge, skills and experience are required to lead and operate competitive and regulated businesses and shared services departments. Failure to manage human resources risk could adversely affect the business, results of operations, financial condition or prospects of the Corporation. We have mitigated this risk by implementing a number of programs to attract, develop and retain personnel, including recruiting, career development, recognition and competitive compensation and benefits programs.

We believe we have an effective relationship with the Corporation's unions. There are risks that successful negotiations will not be completed with collective bargaining units on mutually agreeable terms. Difficulties in negotiating these agreements or continuing these programs could lead to higher employee costs, a work stoppage or strike and attraction or retention rates below expectations. We have two collective bargaining agreements covering our workforce. One of these collective bargaining agreements has expired on December 31, 2013, and one of these collective bargaining agreements was renewed in early 2012 and is now set to expire on December 31, 2014. Exposure in relation to a breakdown in labour relations with either of the two unions is possible. Earnings variability could result from workforce attraction and retention issues, the aging workforce and changing values of employees. The Corporation also could be impacted by security breaches and property theft at its facilities and workplaces. Considering the mitigations and current conditions, the human resources risk in the one-year period is considered to be low.

TECHNOLOGICAL RISK

We utilize complex technologies in all aspects of the business, from generation through to information technology. Improvements in current technologies and development of new technologies could render certain existing technologies obsolete. Alternative energy technologies such as fuel cells, micro-wind turbines, cogeneration and solar photovoltaic cells have become more accessible and cost competitive. As research and development continues on these alternative technologies, they become more economically viable energy sources. As well, newly constructed facilities are able to incorporate more efficient technologies. New laws and environmental regulations can require upgrades to current facilities' technologies. Our ability to interface with customers is managed through extensive billing and customer care information technology systems. New developments in information systems could render these billing and customer care systems obsolete. We actively monitor regulatory changes and the potential technological impacts of these changes. We are also investing in the development of advanced alternative technologies in generating and information systems. An information management failure, an overall operational system failure, failure of aging applications and infrastructure are all events that individually could result in a low impact in earnings variability but combined could result in moderate earnings volatility. As well, unauthorized access to confidential information and leakage of sensitive data could result in earnings variability. Finally, a loss of the data centre, could result in earnings variability. Overall the technological risk within the one-year time frame is considered as low.

LIQUIDITY RISK

A need to raise additional capital may occur if sources of cash and cash flow from operations are insufficient to fund activities. Such additional capital may not be available when it is needed or on favourable terms for a number of reasons, including changes in market conditions or perceptions of the investment community. We may be required to post collateral to support certain contracts which were executed to hedge commodity positions. Downgrades to credit ratings by credit rating agencies could affect our ability to access capital on favourable terms and within a desired time frame and could also increase the amount of collateral required to be provided to counterparties. We actively monitor our cash position and anticipated flows to achieve adequate funding levels. We communicate regularly with credit rating agencies and the investment community regarding our capital position.

ENMAX has a DB pension plan for qualifying employees. Our contributions to the pension plan are based on periodic actuarial valuations, the next of which is being completed for December 31, 2015. For accounting purposes, as at December 31, 2013, the pension plan had an estimated deficit of $32.0 million ($67.6 million at December 31, 2012). The actual amount of contributions required in the future will depend on future investment returns, changes in benefits and actuarial assumptions. Failure to effectively manage financial resources and related exposures could adversely affect the business, results of operations, financial condition or prospects of the Corporation. To manage this risk, we engage expert pension managers and have investment policies and procedures in place to set out the investment framework of the funds, including permitted investments and various investment constraints. These policies and procedures are approved annually by the Human Resources and Governance Committee of the Board, which also actively monitors the performance of the pension plan.

Exposure to earnings variability exists if credit ratings were to be downgraded, covenants were breached on recourse debt, or insufficient liquidity was experienced. There is also potential exposure to earnings variability as a result of negative pension asset performance. Overall, liquidity risk in the one year timeframe is considered low.

For additional details on our liquidity risk exposures, refer to Note 4 in the Notes to the Consolidated Financial Statements. For additional details on our pension plan, refer to Note 13 in the Notes to the Consolidated Financial Statements.

CREDIT RISK

We enter into agreements and engage in transactions with a number of external parties, such as suppliers, service providers, retail customers and other counterparties. In such arrangements, exposure exists to counterparty credit risks and the risk that one or more counterparties may fail to fulfill their obligations, including paying for or delivery of commodities. These risks are often exacerbated during periods of sustained low commodity prices and tighter credit markets.

We have implemented a credit risk management program to mitigate exposure to credit risk. While we seek to manage credit risk exposure by considering creditworthiness before and after entering into such agreements, monitoring business activity against pre-defined credit limits and obtaining collateral when it is prudent to do so, we may not be able to identify and avoid all counterparties that are not creditworthy. Defaults by suppliers, service providers, retail customers and other counterparties could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

We have credit and collections activities to monitor credit risk exposures, and have implemented available measures to protect against any future losses. In specific situations, this includes but is not limited to a reduction of credit limits, requests for additional collateral, requirements for performance bonds on significant projects or restriction of new transaction terms.

Financial results could be affected as a result of industrial, commercial or institutional customer default or as a result of default by residential, small commercial and wholesale customers. We consider credit risk to be low over the one-year term. For additional details on our credit risk exposures, refer to Note 4 in the Notes to the Consolidated Financial Statements.

DEVELOPMENT RISK

Our ability to successfully complete generation, transmission and distribution assets currently under construction, those projects yet to begin construction, or capital improvements to existing facilities in a timely manner and within established budgets, is contingent upon many variables and subject to a variety of risks, some of which are beyond our control. Should any such risks come to bear additional costs, delays to the in-service dates of these projects, termination payments under committed contracts and/or the write-off of the investment in the project could be experienced. In addition, while our business model is designed to mitigate exposure to risks (as does our strategy to fix the development costs by contractually fixing the price with contractors), we may be required to purchase additional electricity or natural gas to fulfill demand obligations until these projects are completed.

Our ability to successfully identify, value, evaluate, complete and integrate new acquisition opportunities, organic growth opportunities and major capital projects is subject to risks, including increased competition for acquisition targets, capital and other resources resulting from consolidation of the industry and the performance of the Alberta economy. Such business development challenges could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

We budget for capital programs and projects on an annual basis and for specific approved capital programs and projects on an ongoing basis. We perform risk assessments and develop risk treatment plans for major capital programs and projects. Project performance relative to expectations is regularly reported to the Board and any corrective measures are taken as required. Delays and overspending in the development of capital projects could affect our financial results. Overall in the one year period, development risk is considered to be low.

LEGAL RISK

Occasionally, costs and other effects of legal and administrative proceedings, settlements, investigations, claims and actions, in addition to, the effect of new or revised tax laws, rates or policies, accounting standards, securities laws and corporate governance requirements are experienced. Non-compliance with existing laws, resolution of legal actions and changes to the legal environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

We review and actively monitor business activity that could be subject to public or private legal actions, including changes to certain legislation, contracts with outside parties and incidents or claims and have implemented programs to mitigate our legal risk exposures. Earnings variability as it relates to potential employment rights violations which results in union, legal or regulatory action; an incident of material unauthorized communication, a breach of material contract or litigation; litigation for any alleged negligence, defamation, nuisance or other matters; or a material breach of legislation or rules is possible. Legal risk is assessed as being low in the one-year time period.

CORPORATE STRUCTURE RISK

We conduct a significant amount of business through subsidiaries and joint ventures. The ability to meet and service debt obligations is dependent on the operational results of these investments and their ability to distribute funds to ENMAX. Any restrictions on the ability of these investments to distribute funds to ENMAX may affect our ability to service the corporate debt. A change in the corporate structure of ENMAX has been assessed as a low risk in the one year period.

REPORTING/DISCLOSURE RISK

The application of critical accounting policies reflects complex judgments and estimates. These policies include industry-specific accounting applicable to regulated public utilities, accounting for pensions and derivative instruments. The adoption of new accounting standards or changes to current accounting policies or interpretations of such policies could adversely affect the business, results of operations, financial condition or prospects of the Corporation. We have implemented various programs to reinforce our ICFR, including periodic assessments of controls by internal and external auditors and review of certain disclosures by the Board. Transition to IFRS could also adversely affect the reported earnings of the business and impact the prospects of the Corporation. We are nearing completion of a comprehensive project to assess the impacts of IFRS transition and to ensure appropriate controls over financial reporting are maintained through the conversion period and beyond. The risk that errors in consolidated financial statements could cause a loss of credibility with creditors and increase risk of breach of covenants or a decrease in debt ratings is considered to be a low risk in the one-year time frame.

TAX RISK

Prior to January 1, 2001, the legal entities comprising the ENMAX group of companies were not subject to federal or provincial income taxes based on an exemption for municipally owned corporations in the Canadian Income Tax Act (ITA). The exemption generally requires corporations be wholly owned by a municipality and substantially all income must be derived from sources within the geographic boundaries of the municipality. Entities that do not meet these requirements are subject to income tax.

In 2001, the Government of Alberta introduced a payment in lieu of tax (PILOT) regulation in conjunction with the deregulation of the Alberta utilities industry. The purpose of this regulation was to level the playing field between municipally owned tax-exempt entities and non-tax-exempt organizations participating in the competitive part of the electricity market, by requiring tax-exempt organizations to make a payment in lieu of taxes equal to what they would have had to pay if they were not tax-exempt. This regulation required municipally owned retailers and municipally owned PPA holders to remit PILOT payments to the Balancing Pool, based on the retail and commodity components of their electricity operations. PILOT regulations do not apply to those entities subject to tax under the ITA.

With the introduction of PILOT regulations in 2001, certain of our entities experienced a change in tax status. This resulted in all PILOT-related assets (primarily the PPA owned at that time) being deemed to be disposed of and immediately reacquired at fair market value for tax purposes effective December 31, 2000. As a result, the tax base of these assets exceeds their net book value resulting in a future income tax asset of $315.3 million being recorded in the Consolidated Financial Statements with a corresponding increase in retained earnings. As at December 31, 2013, the future income tax asset remaining related to this balance is $54.7 million. We have received reassessments and communications from Alberta Finance in respect of the taxation years 2001 through 2010 related to this tax base. We do not agree with the reassessments and have commenced the necessary steps to defend our positions through the formal appeals and litigation process. We expect this process to be successful and will evaluate all options should the appeals and litigation process result in an unfavourable outcome.

The Alberta Electric Utilities Act precludes municipally-owned corporations competing in the electricity generation business from realizing a tax, subsidy or financing advantage as a result of their association with the municipality. Accordingly, we hold generation assets in entities that do not qualify for the income tax exemptions noted above.

The computation of our provision for income taxes involves tax interpretations, regulations and legislation that are continually changing. Tax filings are subject to audit by taxation authorities and the outcome of such audits may increase tax liabilities. Any implementation of incremental taxes or changes to the current legislation could adversely affect the business, results of operations, financial condition or prospects of the Corporation. Earnings variability in relation to reassessments from Alberta Finance in regards to prior years’ returns and other contingent tax liabilities is possible. Considering the above, tax risk is considered to be a moderate-low risk to the Corporation in the one year timeframe.

STRATEGIC RISK

Our business model and strategic direction are predicated on certain assumptions, including the long-term viability of the competitive and regulated businesses, benefits associated with holding each of these businesses, evolution of technology used in the industry and attractiveness of growth opportunities. While we believe these assumptions will remain valid in the future, significant changes to the overall business environment or other factors could cause us to re-evaluate our business model or strategic direction.

We have several competitors that operate in the markets where we serve customers. Competitors vary in size from small companies to large corporations, some of which have significantly greater financial, marketing and procurement resources than us. ENMAX Energy must also compete with the RRO service provided by various parties throughout Alberta in order to convince customers to select ENMAX Energy as their competitive retailer. Changes to the business environment and failure to attract and retain customers could adversely affect the business, results of operations, financial condition or prospects of the Corporation. Earnings variability as it relates to constraints on growth targets for market share is possible.

FINANCIAL INSTRUMENTS

In conducting our operations, we use various instruments including forwards, futures, swaps and options to reduce its market risks.

FORWARDS

Forwards are contractual agreements to purchase or sell a specific commodity or financial instrument at a specified price and date in the future with another counterparty. We enter into forwards to mitigate the impact of volatility in commodity prices and foreign exchange rates. A risk associated with using forwards includes credit risk of the counterparty, as forwards are transacted with a specific counterparty as opposed to a brokerage or clearing exchange. This credit risk is managed in the same respect as trade accounts receivable. A second risk is that if the quantities and timing of the underlying commodity or cash flow are not identical to the contract entered into, we will have continued exposure to market risk. The risk is minimized by attempting to match the settlement terms on all forwards. Amounts related to forwards will appear in the statement of income in electricity costs, natural gas costs and OM&A. The only significant assumptions required in determining fair value of our forward contracts is for long-dated Alberta power purchases and sales, as they are not always traded in an active market. Assumptions must be made based on the pricing of the furthest dated active market transactions occurring and the shape of the forward curve into the future in order to derive a fair value price for these long-dated contracts.

FUTURES

Futures are contractual agreements to purchase or sell a specific commodity or financial instrument at a specified price and date in the future with a brokerage or clearing exchange. We enter into financial futures contracts to mitigate the impact of volatility in commodity prices and foreign exchange rates. Credit risk of the counterparty in futures contracts is minimal, as futures are transacted with a clearinghouse or clearing exchange that guarantees performance of the contract based on margin posted by other market participants. A second risk is that if the quantities and timing of the underlying commodity or cash flow are not identical to the contract entered into, we will have continued exposure to market risk. The risk is minimized by attempting to match the settlement terms on all financial futures entered into. Amounts related to futures will appear in the statement of income in electricity costs, natural gas costs and OM&A. Assumptions must be made based on the pricing of the furthest dated active market transactions occurring and the shape of the forward curve into the future in order to derive a fair value price for these long-dated contracts.

SWAPS

We enter into swaps with counterparties to exchange streams of payments over time outlined by specified terms. We use commodity, cross-currency and interest rate swaps to mitigate the impact of changes in commodity prices, foreign exchange rates and interest rates. A risk associated with using swaps includes credit risk of the counterparty, as they are transacted with a specific counterparty as opposed to a brokerage or clearing exchange. This credit risk is managed in the same manner as trade accounts receivable. A second risk is that if the quantities and timing of the underlying commodity or cash flow are not identical to the contract entered into, we will have continued exposure to market risk. The risk is minimized by attempting to match the settlement terms on all swaps entered into. Amounts related to swaps will appear in the statement of income in electricity costs, natural gas costs, OM&A and interest. There are no significant assumptions required when determining the fair value of our option contracts as they can be valued using active market rates.

OPTIONS

Options are contractual agreements with counterparties that give the purchaser the right, but not the obligation, to buy or sell a specific amount of commodity or financial instrument at a fixed price, either at a fixed date or at any time within a specified period. A risk of using options is that if the quantities and timing of the underlying commodity or cash flow are not identical to the contract entered into, there will be ineffectiveness and we will have continued exposure to market risk. Another risk of options is that the writer of an option has a fixed upside (option premium) on the transaction with significant downside. The purchaser of an option has the additional risk that if the market is static, the option premium will be forfeited at the expiration date without any realized upside. These risks are minimized by attempting to match terms of options to offset existing positions which have market risk. Amounts related to options will appear in the statement of income in electricity costs, natural gas costs, OM&A and interest. There are no significant assumptions required when determining the fair value of our option contracts as they can be valued using active market rates.

ENERGY TRADING DERIVATIVES

Energy trading derivatives are contracts-for-differences that are financial forwards and futures for electricity and gas positions. This does not include electricity and gas contracts that are not considered to be accounting derivatives (normal purchase and sale contracts). The fair value of ENMAX Energy'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, 2013, and December 31, 2012.

OUTSTANDING CONTRACTS-FOR-DIFFERENCES

As at December 31	2013	2012
Notional quantities:		
Electricity sales *(GWh)*	3,958	2,818
Natural gas sales *(TJ)*	670	319
Electricity purchases *(GWh)*	6185	4,556
Natural gas purchases *(TJ)*	19,615	14,585

At December 31, 2013, on the basis of electricity and natural gas prices at that date, the fair market value of these contracts amounted to an unrealized negative mark-to-market adjustment of $3.2 million as compared to negative mark-to-market adjustment of $0.2 million as at December 31, 2012. This amount does not reflect the fact that these contracts will settle at prices in effect in the future.

Refer to Note 3 in the Notes to the Consolidated Financial Statements for further information on financial instruments.

CLIMATE CHANGE AND THE ENVIRONMENT

ENVIRONMENTAL RISKS

Refer to Risk Management and Uncertainties section for discussion regarding environmental risks.

TRENDS AND UNCERTAINTIES

Environmental matters cause certain trends and uncertainties to exist. Customers are becoming more attuned to the source of their energy. As a result, the need to offer energy from alternative production methods and renewable resources is increasing. Based on our asset portfolio, we are positioned to offer consumers choices and progressive technologies that will help increase revenues should this trend continue to develop. The Home Solar program which was launched in 2011 provides residential and commercial customers the opportunity to generate their own solar and wind power.

ASSET RETIREMENT OBLIGATIONS

At December 31, 2013, asset retirement obligations exist relating to the following generating assets: McBride, Taber, Kettles, Crossfield and CEC. The accretion expense on these assets is included in OM&A in the Consolidated Statements of Earnings and Comprehensive Income.

EXPECTED REMEDIATION LIABILITY AND TIMING FOR EACH ASSET

(millions of dollars)	Date	Amount
McBride	September 2057	47.8
Taber	December 2057	32.4
Kettles	May 2071	26.2
Crossfield	December 2048	10.4
CEC	March 2043	29.6

ENVIRONMENTAL LIABILITIES

Environmental liabilities recorded in our financial statements consist of GHG liabilities. These obligations relate to electricity generated from both our PPAs and CEC. These items have been reflected as liabilities in the Consolidated Financial Statements as at December 31, 2013. We continue to actively monitor the EMS and will continue to abide with current and future environmental regulations.

We currently have no outstanding lawsuits in litigation for environmental matters. There are no other known environmental liabilities at this point in time or foreseen in the future.

Provincial legislation aimed at reducing emissions of high GHG emitting facilities, including coal-fired plants, was passed a number of years ago and resulted in costs being incurred. Further expenditures are required to be spent in future years to comply with this legislation, and there is an expectation that ongoing operating costs will increase as a result of these compliance matters.

TRANSACTIONS WITH RELATED PARTIES

Our related-party transactions comprise both revenues from and expenditures to The City. The City is the sole shareholder of ENMAX. Total revenues received from The City for the year ended December 31, 2013 were $121.1 million (2012 - $109.8 million). The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services and billing and customer care services relating to The City's utilities departments. We have committed to a water supply agreement with The City, to commence upon completion of Shepard, whereby The City will supply a specified amount of water annually to facilitate Shepard operations. As at December 31, 2013 amounts owing to us from The City for services provided were $31.2 million (December 31, 2012 – $26.4 million).

Total expenditures for goods and services provided by The City for the year ended December 31, 2013, were $137.1 million (2012 – $155.4 million). Most of these expenditures were for local access fees for use of The City's rights-of-way, the cost of which is passed directly to transmission and distribution customers.

Transactions between ENMAX and The City have been recorded at the exchange amounts. Exchange amounts are the amounts outlined by the contracts in effect between us and The City. The measurement basis used in determining the above values is the contract amount which is considered fair market value; that is, the measurement basis is likely the same as would be used for a third-party arm's-length transaction.

We borrow from The City through arrangements with the ACFA to fund ongoing investment relating to the regulated transmission and distribution network in Calgary and the surrounding area. The total amount of debt owed to The City was $915.5 million at December 31, 2013 (December 31, 2012 – $827.8 million). Interest paid on this debt for the year ended December 31, 2013, was $37.6 million (2012 –$35.5 million). We are required to reimburse The City for all principal and interest payments with respect to this debt on the same days as The City disburses the payments to the debt holders. In addition, we are required to pay a loan guarantee and administration fee to The City of 0.25 per cent on the average monthly outstanding debenture balance held by the City on behalf of ENMAX. For the year ended December 31, 2013, $2.2 million was paid to The City for this fee (2012 - $2.2 million)

Additional details on our transactions with The City can be found in Note 25 in the Notes to the Consolidated Financial Statements.

MATERIAL CONTRACTS

Material contracts are those considered outside of the ordinary course of business. As discussed earlier, CPLP acquired a 50 per cent interest in the 800 MW natural-gas-fired Shepard in 2013. Upon entering this arrangement, the parties also entered into an ESA and a JVA in 2013. Through a 20-year ESA, we will contract to purchase 300 MW of CPLP's Shepard output for the first three years of the ESA term and 200 MW for the remaining 17 years of the ESA term. Both parties hold their ownership interests in an unincorporated joint venture with agreement to build, own and operate the facility under a JVA. Under the JVA, we will continue to provide construction management services to the parties, are appointed as the operator for the provision of operating and maintenance services, and are appointed as joint venture manager for the provision of accounting and settlement services. An affiliate of CPLP has been appointed as the real-time operator to dispatch each party's electricity entitlement under the AESO rules. A management committee has been established to manage and govern the joint venture.

INTEREST OF EXPERTS

INDEPENDENT AUDITOR

ENMAX's external auditor is Deloitte LLP, Chartered Accountants, Suite 700, 850 – 2 Street SW, Calgary, Alberta, T2P 0R8. Deloitte LLP is independent with respect to ENMAX within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

ACTUARY

ENMAX utilizes external professional services in relation to its employee benefits from Towers Watson, Suite 1600, 111 – 5 Avenue SW, Calgary, Alberta, T2P 3Y6. Towers Watson is independent with respect to ENMAX, as they have no equity interest in the Corporation and are compensated at a contracted fixed rate, regardless of the outcome of their reports.

LEGAL AND REGULATORY PROCEEDINGS

The Corporation is occasionally named as a party in various claims and legal proceedings which arise during the normal course of its business. The Corporation reviews each of these claims, including the nature of the claim and the amount in dispute. Although there is no assurance that each claim will be resolved in favour of the Corporation, the Corporation does not believe that the outcome of any claims or potential claims it is currently aware of will have a material adverse effect on the financial results or position of Corporation, after taking into account amounts previously reserved by the Corporation. For further information, refer to Note 19 in the Notes to the Consolidated Financial Statements.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

The President and Chief Executive Officer ("CEO") and the Executive Vice President, Finance and Chief Financial Officer ("CFO") of ENMAX, together with management, have established and maintain disclosure controls and procedures for the Corporation in order to provide reasonable assurance that material information relating to the Corporation is made known to them in a timely manner, particularly during the period in which the annual filings are being prepared. The CEO and CFO of ENMAX, together with management, have evaluated the design and operating effectiveness of the Corporation's disclosure controls and procedures as of December 31, 2013 and, based on that evaluation, have concluded that these controls and procedures are effective in providing such reasonable assurance.

The CEO and CFO of ENMAX, together with management, are also responsible for establishing and maintaining ICFR within the Corporation in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with GAAP. The CEO and CFO of ENMAX, together with management, have evaluated the design and operating effectiveness of the Corporation's ICFR as of December 31, 2013 and, based on that evaluation, have concluded that the controls are effective in providing such reasonable assurance. During 2013, there were no changes in the Corporation's ICFR that materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

OUTLOOK

The discussion in this section is qualified by the caution to reader at the beginning of the Financial Report. The financial results forecasted for 2014 are based on certain assumptions about factors that are outside of the control of the Corporation or management. Actual results that differ from these assumptions could have a significant impact on expected results. The key assumptions that could significantly impact forecast earnings are commodity prices, residential and small business volumes, unplanned outages at generating facilities, settlement of contingencies, regulatory changes and project execution on the Corporation's large capital projects.

The market price outlook for electricity in 2014 is expected to be lower than 2013 due primarily to fewer and shorter plant outages and the projected mid-year commissioning of new wind supply. We expect natural gas prices to remain at relatively low levels. Spark spreads are expected to be lower due to higher natural gas prices and lower electricity prices. The expected financial results for 2014 will reflect the impact of the expiration of capacity ownership of the Battle River units #3 and #4 under the PPA which is partially offset by the lower impact of unplanned outages and replacement power purchases. Market share in commercial and residential markets is expected to remain constant. The volume contracted in each customer segment will be a function of availability for contracting and profitability, including alignment with the supply portfolio.

The Company's regulated business has completed its FBR period. We did not receive adequate returns through this seven-year period (and currently have an application pending to reopen the recovery of past transmission costs). We have filed a cost of service application and are in the process of filing for a new PBR mechanism. The transmission business is not well suited for PBR and, therefore, beginning in 2014, our transmission business will revert to a traditional cost of service regulatory model. Rebasing of our distribution business and the move back to a cost of service framework for our transmission business has several implications including: i) earnings for both distribution and transmission should increase with the inclusion of assets previously excluded from rate base; and ii) upward operating cost pressures will have a significant influence on go-forward revenue rates.

Management has set significant targets for margin improvement and cost reductions across the Corporation. While aggressive, we have plans to achieve these improvements and are committed to meeting these targets. Overall, profitability in 2014 is expected to be similar to 2013 profitability from continuing operations (before gain on sale).

CONSOLIDATED FINANCIAL STATEMENTS

CONTENTS

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The preparation and presentation of the accompanying consolidated financial statements of ENMAX Corporation are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors (the Board). In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 7, 2014. Financial information presented elsewhere in this report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit, Finance and Risk Committee (AFRC) of the Board.

The consolidated financial statements have been examined by Deloitte LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with GAAP. The auditors' report outlines the scope of their audit examination and states their opinion.

The Board, through the AFRC, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The AFRC, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The AFRC reviews the consolidated financial statements and annual financial report and recommends their approval to the Board. The external auditors have full and open access to the AFRC, with and without the presence of management. The AFRC is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Gianna Manes
President and Chief Executive Officer

David Halford, CPA, CA
Executive Vice President, Finance and Planning,
Chief Financial Officer and Chief Risk Officer

March 5, 2014

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of ENMAX Corporation:

We have audited the accompanying consolidated financial statements of ENMAX Corporation, which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012; and the consolidated statements of earnings and comprehensive income, shareholder's equity and cash flows for the years then ended, and the notes to the consolidated financial statements.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of ENMAX Corporation as at December 31, 2013 and December 31, 2012, and its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte LLP

Chartered Accountants
March 5, 2014
Calgary, Alberta

CONSOLIDATED BALANCE SHEETS

As at December 31, (millions of dollars)		2013		2012
ASSETS				
Cash and cash equivalents	$	80.6	$	45.5
Accounts receivable *(Notes 4 and 5)*		665.5		663.6
Income taxes receivable		96.9		90.6
Future income tax asset *(Note 6)*		8.7		7.2
Other current assets *(Notes 4, 7 and 8)*		42.6		45.8
Assets held for sale *(Note 9)*		–		575.6
		894.3		1,428.3
Property, plant and equipment *(Note 10)*		3,022.6		2,694.5
Power purchase arrangements *(Note 11)*		369.5		422.2
Intangible assets *(Note 12)*		124.3		116.3
Goodwill		16.0		16.0
Employee future benefits *(Note 13)*		22.8		18.5
Future income tax asset *(Note 6)*		59.0		61.0
Other long-term assets *(Notes 4, 5, 7 and 8)*		57.0		63.1
TOTAL ASSETS	$	4,565.5	$	4,819.9
LIABILITIES				
Short-term debt *(Note 14)*	$	–	$	165.9
Accounts payable and accrued liabilities *(Notes 4 and 5)*		436.8		612.6
Income taxes payable		–		12.0
Future income tax liability *(Note 6)*		0.5		3.4
Current portion of long-term debt *(Notes 4 and 15)*		63.7		59.7
Other current liabilities *(Notes 4 and 7)*		52.8		59.3
Liabilities held for sale *(Note 9)*		–		9.5
		553.8		922.4
Long-term debt *(Notes 4 and 15)*		1,375.3		1,549.8
Future income tax liability *(Note 6)*		100.1		84.8
Other long-term liabilities *(Notes 4 and 7)*		60.7		86.6
Asset retirement obligations *(Note 16)*		15.4		14.4
		2,105.3		2,658.0
SHAREHOLDER'S EQUITY				
Share capital *(Note 17)*		280.1		280.1
Retained earnings		2,186.4		1,901.4
Accumulated other comprehensive income (loss) *(Note 18)*		(6.3)		(19.6)
		2,460.2		2,161.9
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$	4,565.5	$	4,819.9

Commitments and contingencies (Note 19)
See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

Year Ended December 31, (millions of dollars)	2013	2012
REVENUE *(Note 3)*		
Electricity	$ 2,388.7	$ 2,276.5
Natural gas	389.3	300.1
Transmission and distribution	339.0	299.4
Local access fees	129.3	148.3
Contractual services	95.4	125.8
Other	22.4	10.0
TOTAL REVENUE	3,364.1	3,160.1
COST OF SERVICES PROVIDED *(Note 3)*		
Electricity	2,072.0	1,859.5
Natural gas	364.3	281.7
Transmission and distribution	97.8	100.5
Local access fees	129.3	148.3
Contractual services	61.1	93.8
Operations, maintenance and administration	273.6	241.3
Foreign exchange (gain) loss	(6.6)	6.4
TOTAL COST OF SERVICES PROVIDED	2,991.5	2,731.5
	372.6	428.6
Amortization	168.1	164.4
Interest *(Note 21)*	33.1	40.2
Current income tax (recovery) expense *(Note 6)*	(10.0)	5.1
Future income tax expense *(Note 6)*	8.0	3.3
NET EARNINGS FROM CONTINUING OPERATIONS	173.4	215.6
Net earnings from discontinued operations, net of tax *(Note 9)*	3.2	9.4
Gain on sale of subsidiary *(Note 9)*	175.9	–
NET EARNINGS	352.5	225.0
OTHER COMPREHENSIVE INCOME, NET OF TAX		
Unrealized gains on derivatives designated as cash flow hedges, includes future income tax expense of $9.7 (2012 – $9.3 tax expense)	24.1	22.3
Realized (gains) losses on derivatives designated as cash flow hedges in prior periods transferred to net earnings in current year, includes future income tax expense of $6.3 (2012 – $1.2 benefit)	(10.8)	26.9
Other comprehensive income, net of tax	13.3	49.2
COMPREHENSIVE INCOME	$ 365.8	$ 274.2

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

(millions of dollars)	Share Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
BALANCE, JANUARY 1, 2012	$ 280.1	$ 1,732.4	$ (68.8)	$ 1,943.7
Net earnings	–	225.0	–	225.0
Dividends	–	(56.0)	–	(56.0)
Other comprehensive income including future tax expense of $10.5 *(Note 18)*	–	–	49.2	49.2
BALANCE, DECEMBER 31, 2012	280.1	1,901.4	(19.6)	2,161.9
Net earnings	–	352.5	–	352.5
Dividends	–	(67.5)	–	(67.5)
Other comprehensive income including future tax expense of $3.4 *(Note 18)*	–	–	13.3	13.3
BALANCE, DECEMBER 31, 2013	**$ 280.1**	**$ 2,186.4**	**$ (6.3)**	**$ 2,460.2**

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31, (millions of dollars)	2013	2012
CASH PROVIDED BY (USED IN):		
OPERATING ACTIVITIES		
Net earnings	$ 352.5	$ 225.0
Net earnings from discontinued operations	(3.2)	(9.4)
Gain on sale of subsidiary	(175.9)	–
Items not involving cash *(Note 23)*	186.3	171.4
	359.7	387.0
Change in non-cash working capital *(Note 24)*	(136.2)	111.9
Employee future benefits	(4.7)	7.0
Cash flow from continuing operating activities	218.8	505.9
Cash flow from discontinued operations	(14.1)	52.3
	204.7	558.2
INVESTING ACTIVITIES		
Purchase of property, plant and equipment	(298.8)	(395.3)
Net proceeds from disposal of assets held for sale	802.2	–
Additions to power purchase arrangements	–	(1.4)
Other assets	(14.0)	26.3
Contributions in aid of construction	15.7	12.3
Cash flow from continuing investing activities	505.1	(358.1)
Cash flow from discontinued operations	(269.6)	(215.6)
	235.5	(573.7)
FINANCING ACTIVITIES		
Repayment of short-term debt	(1,588.5)	(2,784.6)
Proceeds of short-term debt	1,422.6	2,783.8
Proceeds of long-term debt *(Note 15)*	140.6	143.4
Repayment of long-term debt	(311.1)	(56.1)
Dividend paid	(67.5)	(56.0)
Other long-term liabilities	(1.2)	(4.9)
	(405.1)	25.6
Increase in cash and cash equivalents	35.1	10.1
Cash and cash equivalents, beginning of year	45.5	35.4
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 80.6	$ 45.5
Supplementary information:		
Interest paid	$ 89.1	$ 87.4
Income taxes paid	6.8	36.9
Cash and cash equivalents consist of:		
Cash	$ 79.9	$ 40.7
Short-term investments	0.7	4.8

See accompanying Notes to Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF THE 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 is an operating segment established to carry out competitive energy supply and retail functions through various legal entities and affiliated companies.

ENMAX POWER

ENMAX Power is primarily a regulated segment established to carry out electricity transmission and distribution service functions and the regulated rate option (RRO) retail function through various legal entities and affiliated companies. ENMAX Power also provides non-regulated engineering, procurement, construction and maintenance services.

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 and the proportionate share of its joint ventures are included in the consolidated financial statements of the Corporation.

All inter-company accounts and transactions have been eliminated, except as described in Note 5.

MEASUREMENT UNCERTAINTY

The preparation of the Corporation's consolidated financial statements, in accordance with GAAP, 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 are required to capture, completely and accurately, all customer movement, load classification and consumption data. By regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until four months after the month in which such electricity was consumed. The data and associated processes and systems 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. Any changes to electricity revenues and costs arising from these estimation processes will be accounted for as a change in estimate in the period they occur.

For determining potential impairment, the Corporation is required to estimate the recoverable values of certain assets. Estimates of recoverable values are based on undiscounted cash flow techniques which rely on a number of assumptions, such as the amount of future cash flows that will be generated from the asset, expected future prices for inputs and outputs and expected usage of the asset.

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 accounts receivable, historical write-offs, assessments of the collectability 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 based on estimates of useful life characteristics of common assets.

Measurement of the Corporation's asset retirement obligations 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, inflation rates and discount rates.

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 more likely than not, 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 in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, pursuant to subsequent regulatory decisions or other regulatory proceedings.

Certain financial instruments are recorded at fair value. These fair values can be subject to estimates of inputs other than quoted market prices, future prices, expected cash flows and discount rates.

ENMAX has a defined benefit (DB) pension plan and post-retirement benefits that are provided to certain employees. The cost of these benefits recognized in the consolidated financial statements are subject to estimates around many factors including, but not limited to, assumptions of future return on plan assets, retirement age, mortality rates, discount rates, future health care costs, salary escalation rates and claims experiences.

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

CASH AND CASH EQUIVALENTS

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

INVENTORY

Inventory is comprised of items held for sale and products held for lease. Inventory is valued at the lower of cost and net realizable value. Cost is determined using the weighted-average cost method for all types of inventory and the first-in-first-out method is applied to products held for lease. Cost includes direct materials and, where applicable, direct labour costs and overhead charges incurred in bringing the inventories to their present location and condition. Net realizable value is determined as the expected selling price less all estimated costs to completion and costs to be incurred in marketing, selling and distribution.

PROPERTY, PLANT AND EQUIPMENT

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

PPE AMORTIZATION RATES

Transmission, distribution and substation equipment	0.00%	–	22.72%
Tools, systems and equipment	3.33%	–	25.00%
Buildings and site development	0.61%	–	4.60%
Generation facilities and equipment	2.00%	–	10.00%
Vehicles	2.36%	–	8.00%

PPE are recorded at cost, which includes direct labour, material, equipment charges, directly attributable overhead and interest during construction (IDC). IDC is capitalized on a monthly basis on qualifying assets by applying a borrowing rate to the carrying amount of the assets. Qualifying assets are those assets that take a substantial period of time to complete (greater than or equal to six months) or are of such substantial value they would incur significant borrowing costs over a shorter period of time.

The Corporation classifies all major future components of its electricity transmission and distribution system infrastructure as PPE. These items are not amortized until they are placed into service.

Construction in progress represents assets which are not yet available for use and therefore not subject to amortization.

Original costs of retired regulated depreciable assets are charged, and the related net disposal proceeds are credited, to accumulated amortization in a manner consistent with regulatory accounting. 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 5. 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 rates opposite:

INTANGIBLE AMORTIZATION RATES

Customer lists and contracts			10.00%
Computer systems	10.00%	–	25.00%
Land easements, rights and lease options	0.00%	–	25.86%

Intangible assets with indefinite lives include some land easements, renewable energy certificates and water licenses, and are not subject to amortization. These assets are assessed annually for impairment or more frequently if events or changes in circumstances indicate that the asset may be impaired.

ASSET IMPAIRMENT

Long-lived assets subject to amortization are tested for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. Intangible assets with indefinite lives are tested for impairment annually or more frequently when events or changes in circumstances indicate the carrying amount may not be recoverable. An impairment loss would be recognized if the carrying amount exceeds the recoverable 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 undiscounted 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 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 recognized as a change in the carrying amount of the liability for an asset retirement obligation; the related asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. A gain or loss may be incurred upon settlement of the liability.

CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Under various statutory requirements and agreements with customers and developers, the Corporation receives CIAC in the form of cash contributions. Such contributions are recorded as a reduction of PPE and amortized on the same basis as, and offset the amortization charge for, the assets to which they relate.

GOVERNMENT GRANTS

Government grants are accounted for using the income approach. Under this method, amounts received have been deducted from the carrying amount of the related assets. Government grants are not recognized until there is reasonable assurance that the Corporation will comply with the conditions attached to them and that the grants will be received. Government grants have been received by the Corporation for the purchases of certain items of PPE.

POWER PURCHASE ARRANGEMENTS

The cost to acquire the power purchase arrangements (PPAs) has been recorded on the consolidated balance sheet as a long-term asset. The cost is amortized on a straight-line basis to amortization expense over the useful life of the arrangements.

GOODWILL

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is annually assessed for impairment. Goodwill and all other assets and liabilities have been allocated to the Corporation's segments, referred to as reporting units. To assess impairment, the fair value of each reporting unit is determined and compared to the book value of the reporting unit. If the fair value of the reporting unit is less than the book value, then a second test is performed to determine the amount of the impairment.

The amount of the impairment is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit to determine the implied fair value of goodwill and comparing that amount to the book value of the reporting unit's goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount.

REVENUE RECOGNITION

Revenues are recognized on an accrual basis as services are provided and include an estimate of fees for services provided but not yet billed. For ENMAX Power's billable construction projects, revenue is recognized on the percentage of completion basis. All revenues are reviewed for collectability and recognized only when collection is reasonably assured.

INCOME TAX

The Corporation and its subsidiaries are municipally owned and are generally not subject to federal and provincial income taxes. Those subsidiaries that do not meet the criteria for municipal exemption are taxable under the Canadian Income Tax Act (ITA). The Corporation also records income tax expense based on a regulation to the Alberta Electric Utilities Act (EUA) that requires tax exempt, municipally-owned entities to make payment in lieu of tax (PILOT) on certain portions of their operations. These PILOT payments are made to the Balancing Pool of Alberta.

ENMAX uses the liability method of accounting for income taxes and PILOT. 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 temporary (or timing) differences 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 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 substantive enactment.

FINANCIAL INSTRUMENTS

The financial instruments of the Corporation include held-for-trading instruments, loans and receivables, available-for-sale instruments and other financial liabilities.

Cash and cash equivalents are classified as held-for-trading instruments and are recorded at fair value. Accounts receivable are classified as loans and receivables and are recorded initially at fair value and subsequently carried at amortized cost with interest and other income earned from these financial assets recorded in other revenue. Short-term debt, long-term debt, customer guarantee deposits, dividends payable and accounts payable and accrued liabilities are classified as other financial liabilities and are recorded initially at fair value and subsequently carried at amortized cost using the effective interest method. Investments in equity instruments are classified as available-for-sale instruments and are carried at fair value with changes to fair value recorded through other comprehensive income (OCI). Investments in equity instruments that do not have a quoted market price in an active market are measured at cost. Derivatives such as swaps, futures, options and forwards are classified as held-for-trading instruments and are recorded at their fair value with changes in fair value recorded through earnings. If these derivatives are designated as hedging items, they are accounted for as described in the Hedges section of this note.

Held-for-trading items are required to be classified as such due to their nature as derivative or are items held for the purpose of selling or repurchasing in the near term. Available-for-sale items are non-derivative financial assets that do not fit into any of the other classes of financial assets.

The Corporation uses an allowance for doubtful accounts to reduce the carrying amount of accounts receivables that are impaired. This allowance is based on a number of factors including the aging of accounts receivable, historical write-offs within customer groups, assessments of the collectability of amounts from individual customers and general economic conditions. Write-offs are determined using similar techniques and by reviewing significant amounts on a case-by-case basis.

Other financial assets are reviewed for impairment by comparing their carrying value to fair value. An impairment loss is recorded in earnings during the period in which the fair value falls below the carrying value and such decline is other than temporary.

The Corporation had a procurement contract denominated in Japanese Yen. As this foreign currency is not a common transaction currency of the Corporation, the Corporation's policy is to account for this embedded foreign currency derivative separately from the underlying host contract.

Transaction costs that are directly attributable to the issuance of financial liabilities are netted against the fair value initially recognized. These costs are subsequently expensed to earnings using the effective interest rate method.

HEDGES

In conducting its business, the Corporation uses derivatives and other financial instruments, including forward contracts, swaps, options and contracts-for-differences, to manage its exposure to certain market risks. Certain derivatives are designated as hedging instruments for accounting purposes when meeting certain effectiveness and documentation requirements at inception of the hedging relationship and on an ongoing basis. Effectiveness is measured with reference to the risk management objective and strategy for the hedged item.

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas and foreign exchange. For cash flow hedges, changes in the fair value of the effective portion of the hedging derivative are accumulated in OCI and recognized in net earnings during the periods when the cash flows of the hedged items are realized. Gains and losses on cash flow hedges are reclassified immediately to net earnings when the hedged item is sold or terminated early or when a hedged anticipated transaction is no longer probable. Changes in fair value due to ineffectiveness of hedges and changes in fair value of non-hedge derivatives are recorded in earnings under cost of services provided. Changes in fair value of de-designated or discontinued hedges are recorded in earnings under cost of services provided from the date of de-designation or discontinuation. The unrealized changes in fair value recorded prior to de-designation or discontinuation are reclassified from accumulated OCI to earnings when the related hedged item is recognized in earnings.

FOREIGN CURRENCY TRANSLATION

The Corporation's consolidated financial statements are presented in Canadian dollars, which is the functional currency of the Corporation and all of its subsidiaries.

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year end exchange rates of monetary items and liabilities denominated in foreign currencies are recognized in the statement of earnings, except when deferred in equity as qualifying cash flow hedges.

Foreign exchange gains and losses are presented on the consolidated statements of earnings and comprehensive income within costs of services provided.

EMPLOYEE BENEFIT PLANS

The Corporation sponsors pension plans that contain both DB and defined contribution (DC) provisions. The cost of DB 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.

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

EMISSION CREDITS AND ALLOWANCES

Effective July 1, 2007, the Climate Change and Emissions Management Amendment (CCEMA) Act was enacted into law in Alberta. The CCEMA Act, and regulations made pursuant to it, establishes baseline emission intensity levels for each large generating facility, and emissions over this baseline are subject to a surcharge. Changes in law provisions in the Corporation's PPAs have the potential to expose the Corporation to significant portions of these compliance costs (see Note 19).

Purchased emission allowances are recorded on the consolidated balance sheets as part of intangible assets, at historical cost and are carried at the lower of weighted average cost and net realizable value. Allowances granted to the Corporation or internally generated from approved projects are accounted for as intangible assets.

The Corporation has recorded emissions liabilities on the consolidated balance sheets, as a component of accounts payable and accrued liabilities, using the best estimate of the amount required to settle the obligation in excess of government established emission intensity levels. To the extent compliance costs are charged to the Corporation under the change in law provisions of the Corporation's PPAs, these amounts are recognized as cost of electricity services provided in the period they are charged.

JOINT VENTURE INVESTMENTS

The Corporation accounts for its interest in joint ventures using the proportionate consolidation method. Under this method, the Corporation records its share of the joint venture's assets, liabilities, revenues and expenses line-by-line on its financial statements.

3. SEGMENTED INFORMATION

ENMAX has reclassified the segmented information table to reflect management's review of business segments. The reclassification reflects reporting of ENMAX Encompass Inc. (Encompass) within Corporate and Intersegment Eliminations (Encompass was previously reported with ENMAX Energy). Encompass provides billing and customer care services to residential and small commercial customers, including RRO customers. Prior figures have been reclassified.

	ENMAX Energy		ENMAX Power		Corporate & Intersegment Eliminations		Consolidated Totals	
Year Ended December 31, (millions of dollars)	2013	2012	2013	2012	2013	2012	2013	2012
REVENUE								
Electricity	2,614.9	2,510.2	149.9	185.9	(376.1)	(419.6)	2,388.7	2,276.5
Natural gas	390.0	300.1	–	–	(0.7)	–	389.3	300.1
Transmission and distribution	–	–	339.0	299.4	–	–	339.0	299.4
Local access fees	–	–	129.3	148.3	–	–	129.3	148.3
Contractual services	2.9	6.1	82.2	119.0	10.3	0.7	95.4	125.8
Other	23.3	13.0	4.7	3.5	(5.6)	(6.5)	22.4	10.0
TOTAL REVENUE	3,031.1	2,829.4	705.1	756.1	(372.1)	(425.4)	3,364.1	3,160.1
COST OF SERVICES PROVIDED								
Electricity	2,303.1	2,099.1	143.7	179.0	(374.8)	(418.6)	2,072.0	1,859.5
Natural gas	364.3	281.7	–	–	–	–	364.3	281.7
Transmission and distribution	–	–	97.8	100.5	–	–	97.8	100.5
Local access fees	–	–	129.3	148.3	–	–	129.3	148.3
Contractual services	1.2	3.6	60.1	91.3	(0.2)	(1.1)	61.1	93.8
Operations, maintenance and administration (OM&A)	145.7	144.9	136.0	110.0	(8.1)	(13.6)	273.6	241.3
Foreign exchange loss (gain)	(6.6)	6.4	–	–	–	–	(6.6)	6.4
TOTAL COSTS OF SERVICES PROVIDED	2,807.7	2,535.7	566.9	629.1	(383.1)	(433.3)	2,991.5	2,731.5
	223.4	293.7	138.2	127.0	11.0	7.9	372.6	428.6
Amortization	106.6	107.6	56.8	53.3	4.7	3.5	168.1	164.4
EARNINGS BEFORE INTEREST AND INCOME TAXES (EBIT)	116.8	186.1	81.4	73.7	6.3	4.4	204.5	264.2
Interest							33.1	40.2
Income tax expense (recovery)							(2.0)	8.4
NET EARNINGS FROM CONTINUING OPERATIONS							173.4	215.6
Net earnings from discontinued operations *(Note 9)*							3.2	9.4
Gain on sale of subsidiary *(Note 9)*							175.9	–
NET EARNINGS							352.5	225.0
GOODWILL	16.0	16.0	–	–	–	–	16.0	16.0
CAPITAL ADDITIONS	285.6	263.1	190.3	158.6	26.4	9.9	502.3	431.6

SEGMENTED TOTAL ASSETS

As at December 31, (millions of dollars)	2013	2012
ENMAX Energy	2,881.8	3,410.8
ENMAX Power	1,540.0	1,375.8
Corporate and eliminations	143.7	33.3
	4,565.5	4,819.9

4. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT

RISK ASSOCIATED WITH FINANCIAL INSTRUMENTS AND DERIVATIVES

	Measured Initially at Fair Value and Subsequently at Cost or Amortized Cost			Initially and Subsequently Measured at Fair Value		
As at December 31, 2013 and 2012	Accounts Receivable	Accounts Payable	Short-term Debt and Long-term Debt	Cash and Cash Equivalents	Investments	Electricity and Natural Gas Derivatives
Market risk						
Commodity prices						√
Foreign exchange		√		√		√
Interest rate			√			
Equity price risk					√	
Credit risk	√			√	√	√
Liquidity risk		√	√			√

OVERVIEW OF RISK MANAGEMENT

ENMAX is exposed to market risk, credit risk and liquidity risk. The Corporation's strategy, policies and controls are designed to ensure that the risks it assumes comply with regulatory requirements, ENMAX's internal objectives and its risk tolerance. Risks are managed within limits approved by the Board and applied by senior management.

ENMAX builds and acquires energy infrastructure assets and enters into energy supply contracts to meet its demand obligations, purchases and sells commodities in north american markets both for resale and to manage market risk associated with generation output, enters transactions denominated in foreign currencies (U.S. dollars and Japanese Yen) and borrows funds over short- and long-term time horizons. These activities expose ENMAX to market risk from changes in commodity prices, foreign exchange rates and interest rates which affect the Corporation's earnings and the value of associated financial instruments it holds.

MARKET RISK

ENMAX uses various contractual agreements and financial instruments to manage its energy portfolio and market risk exposures including, but not limited to, the following:

- Energy Services Agreements (ESA) – The PPAs and tolling agreements convey the right to the buyer a level of capacity, electricity and ancillary services from a generating facility. ENMAX has entered into PPAs for the output of electricity from the units at the Keephills and Battle River coal-fired generation facilities. ENMAX has a tolling agreement for 100 per cent of the output of McBride Lake Wind Farm (McBride).
- Swaps – Contractual agreements between two parties to exchange streams of payments over time according to specified terms. ENMAX enters into commodity, cross-currency and interest rate swaps to mitigate the impact of changes in commodity prices, foreign exchange rates and interest rates.
- Forwards and futures – Contractual agreements to purchase or sell a specific commodity or financial instrument at a specified price and date in the future. ENMAX enters into forwards and futures to mitigate the impact of volatility in commodity prices and foreign exchange rates.
- Options – Contractual agreements to convey the right, but not the obligation, for the purchaser to buy or sell a specific amount of a commodity or financial instrument at a fixed price, either at a fixed date or at any time within a specified period. Occasionally, ENMAX enters into option agreements to mitigate the impact of changes in commodity prices, foreign exchange rates and interest rates.

COMMODITY PRICE RISK

ENMAX has inherent positions in electricity and natural gas commodities arising from its owned and controlled supply assets and its demand obligations. While ENMAX Energy's business model is designed to achieve a balanced portfolio, its electricity and natural gas positions experience periodic imbalances resulting in exposures to price volatility from spot or short-term contract markets. The Corporation purchases and sells electricity and natural gas commodities in the wholesale market to mitigate the near-term risk exposures arising from such positions.

While the Corporation does not engage in speculative financial instrument trading, it uses various hedging strategies executed within a controlled environment to mitigate its exposure to commodity price risks, including the use of derivatives instruments such as swaps and forwards. Hedging does not guard against all risks and is not always effective. ENMAX could recognize financial losses as a result of volatility in the market values of these contracts.

RISK ANALYSIS AND CONTROL

ENMAX manages its exposure to market risk (interest rate risk, foreign currency exchange risk, commodity price risk and equity price risk) on a portfolio basis, which includes positions arising from its interests in generation facilities, liability positions arising from its commitments to its customers and transacting positions arising from its hedging activities.

SENSITIVITY ANALYSIS ON MARKET RISKS

The analysis below represents the effect of market risks on the Corporation's results as those risks apply to derivative financial instruments. Non-derivative financial instruments are recorded at cost. The carrying amounts of non-derivative financial instruments are not affected by changes in market variables whereas carrying amounts of derivative financial instruments are affected by market variables.

The following table reflects the sensitivity of the fair value of outstanding derivative instruments to reasonably possible changes in the markets of derivative financial instruments. Market interest rates impact interest rate swaps. Foreign currency exchange rates impact commodity derivatives and foreign currency hedge contracts. Forward prices of natural gas and electricity impact commodity derivatives. The market value of equity investments impacts those instruments carried at fair value.

Certain assumptions have been made in arriving at the sensitivity analysis. These assumptions are as follows:

- The same fair value methodologies have been used as were used to obtain actual fair values in the fair values section of this note.
- Changes in the fair value of derivative instruments that are effective cash flow hedges are recorded in OCI.
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Foreign currency balances, principal and notional amounts are based on amounts as at December 31, 2013, and 2012.
- Interest rate sensitivities are based on Canadian Dealer Offered Rate.
- Sensitivities are exclusive of any potential income tax impacts.

SENSITIVITIES OF MARKET RISKS

As at December 31, (millions of dollars)	2013 Earnings	2013 OCI	2012 Earnings	2012 OCI
Interest rates increase 100 basis points (1% pure rate change)	+ 0.4	+ 11.2	+ 0.5	+ 13.7
Canadian dollar strengthens compared with the U.S. dollar by 10%	– 13.2	+ 0.6	– 9.2	+ 1.2
Forward price of natural gas increases by 10%	–	+ 7.6	–	+6.5
Forward price of electricity increases by 10%	–	+ 14.8	–	+11.6

(1) These sensitivities are based on financial instruments carried at fair value, which include derivative contracts. The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any interrelationship among the factors or taxes. These sensitivities are not necessarily indicative of actual future results.

FOREIGN EXCHANGE AND INTEREST RATE RISK

Foreign exchange and interest rate risks are created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates and/or changes in the market interest rates.

ENMAX is not exposed to significant interest rate risk and volatility as a result of the issuance of fixed-rate long-term debt and the use of interest rate hedging instruments. The fair value of ENMAX's long-term debt and any associated interest rate hedging instruments change as interest rates change, assuming all other variables remain constant. For example, a one per cent increase (decrease) in interest rates as at December 31, 2013, would have an effect on fair value of fixed interest rate debt of $92.4 million decrease (increase) (December 31, 2012 – $99.1 million).

Changes in the value of the Canadian dollar relative to the U.S. dollar could impact the Canadian dollar cost of natural gas, which affects the input cost of the Corporation's natural-gas-fired generation capacity, as well as the cost to the Corporation of offering fixed price gas contracts to its customers. The foreign exchange impact on these gas purchases is offset, when possible, by foreign exchange contracts. Foreign exchange exposure resulting from procurement contracts has also been mitigated by foreign exchange contracts.

CREDIT RISK

ENMAX is exposed to credit risk primarily through its wholesale and retail energy sales business. Credit risk is the loss that may result from counterparties' non-performance. ENMAX evaluates the credit risk of wholesale and retail competitive supply activities separately as discussed below.

The Corporation's maximum financial statement exposure to credit risk is the carrying value of the financial assets, as set out in the table below. This maximum exposure does not necessarily reflect losses expected by management nor does it necessarily reflect losses experienced in the past.

FINANCIAL ASSETS

As at December 31, (millions of dollars)	2013	2012
Cash and cash equivalents (Note a)	80.6	45.5
Accounts receivable (Note b)	665.5	663.6
Other current assets (Note c)	42.6	45.8
Other long- term assets (Note c)	57.0	63.1

(a) Cash and Cash Equivalents

Credit risk associated with cash and cash equivalents is minimized substantially by ensuring these financial assets are placed with governments, well-capitalized financial institutions and other credit worthy counterparties. Continuous reviews are performed to evaluate changes in the credit quality of counterparties.

(b) Accounts Receivable

The majority of the Corporation's accounts receivable are exposed to credit risk. Exposure to credit risk occurs through competitive electricity and natural gas supply activities which serve residential, commercial and industrial customers. The risk represents the loss that may be incurred due to the non-payment of a customer's accounts receivable balance, as well as the loss that may be incurred from the resale of energy previously allocated to serve the customer.

Charges to earnings as a result of credit losses for the Corporation for 2013 totalled $6.8 million (2012 – $6.3 million). Management monitors credit risk exposure and has implemented measures to mitigate losses. In specific situations, this includes, but is not limited to, a reduction of credit limits, requests for additional collateral or restrictions on new transaction terms.

AGING ANALYSIS OF TRADE RECEIVABLES PAST DUE BUT NOT IMPAIRED

As at December 31, *(millions of dollars)*	2013	2012
1-30 days past due	36.1	29.1
31-60 days past due	3.4	3.2
61 days or more past due	10.0	8.4
Total past due	49.5	40.7

CHANGES IN THE ALLOWANCE FOR DOUBTFUL ACCOUNTS

As at December 31, *(millions of dollars)*	2013	2012
Provision at the beginning of the year	6.7	8.7
Increase to allowance	6.8	6.3
Recoveries and write-offs	(5.7)	(8.3)
Provision at end of the year	7.8	6.7

The remainder of the accounts receivable balance outstanding at December 31, 2013, consists of unbilled revenue accruals. No provision has been recorded due to the minimal credit risk at the consolidated balance sheet date.

(c) Other Current and Long-Term Assets

ENMAX measures wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual) adjusted for amounts owed to or due from counterparties for settled transactions and all other amounts owing but not yet due. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where the Corporation has a legally enforceable right of offset and intends to settle on a net basis. ENMAX monitors and manages the credit risk of wholesale operations through credit policies and procedures that include an established credit approval process; daily monitoring of counterparty credit limits; and the use of credit mitigation measures such as margin, collateral, letters of credit and/or prepayment arrangements.

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were to fail to perform its obligations under its contract (for example, fail to provide adequate assurances or credit support), ENMAX could incur a loss that could have a material impact on its financial results.

Additionally, if a counterparty were to default and the Corporation were to liquidate all contracts with that entity, the credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions, and unbilled deliveries and additional payments, if any, that would have to be made to settle unrealized losses on accrual contracts.

The majority of counterparties enabled for wholesale transactions are rated investment grade (BBB- or higher) by recognized rating agencies.

LIQUIDITY RISK

Liquidity risk is the risk that ENMAX will not be able to meet its financial obligations as they fall due. The Corporation's approach to managing liquidity risk is to ensure that it always has sufficient cash and credit facilities to meet its obligations when due.

The following table details the remaining contractual maturities for ENMAX's current and long-term non-derivative financial liabilities, including both the principal and interest cash flows:

CONTRACTUAL MATURITIES OF NON-DERIVATIVE FINANCIAL LIABILITIES

As at December 31, *(millions of dollars)*	2013	2012
2014	**581.2**	374.6
2015	**123.0**	114.4
2016	**136.4**	126.9
2017	**115.2**	105.0
2018	**405.8**	396.0
Thereafter	**1,124.2**	938.5

The following table details the remaining contractual maturities for ENMAX's derivative financial liabilities:

CONTRACTUAL MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

As at December 31, *(millions of dollars)*	2013	2012
2014	**29.0**	23.3
2015	**21.5**	10.4
2016	**9.6**	9.5
2017	**6.4**	7.6
2018	**4.4**	5.8
Thereafter	**6.0**	16.1

As at December 31, 2013, the Corporation is in compliance with all financial covenants related to debt classified as long-term debt on the consolidated balance sheet.

Management typically forecasts cash flows for a period of 12 months and beyond to identify financing requirements. These requirements are then addressed through a combination of committed credit facilities and access to capital markets, as discussed in Note 20 to these consolidated financial statements.

DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded on the consolidated balance sheets at fair value. As at December 31, 2013, the mark-to-market adjustment based on the fair value of these hedge contracts resulted in unrealized gains or losses on derivative instruments, which are included in the consolidated balance sheets as per the table below:

DERIVATIVE ASSETS AND LIABILITIES

As at December 31,	2013		2012	
(millions of dollars)	Hedge Instruments	Non-Hedge Derivatives	Hedge Instruments	Non-Hedge Derivatives
Assets				
Current	**19.7**	**9.9**	15.6	11.9
Non-current	**18.3**	**8.1**	23.5	21.0
Liabilities				
Current	**19.6**	**9.4**	19.8	9.4
Non-current	**22.8**	**25.1**	40.5	32.2

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas, as well as foreign exchange exposure. For cash flow hedges, changes in the fair value of the effective portion of the hedging derivative are accumulated in OCI and recognized in net earnings during the periods when the variability in cash flows of the hedged item is realized. In 2013, there were losses of $7.8 million (2012 – $1.4 losses) recognized in earnings as a reflection of the ineffectiveness of the relevant hedges. Gains and losses on cash flow hedges are reclassified immediately to net earnings when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer likely to occur. During 2013, there was no impact to earnings related to hedges that no longer qualified for hedge accounting (2012-$nil).

Foreign exchange exposures on the Corporation's futures margin trading account are managed through economic hedges. For these hedges, the change in the fair value of the hedging derivative and the hedged items are recognized directly in net earnings. During 2013, there was no impact (2012 – $0.1 million gain) recognized.

The Corporation estimates that, of the $6.3 million of losses reported in accumulated OCI as at December 31, 2013, gains of $0.1 million are expected to be realized within the next 12 months at market prices in effect at the time of settlement.

Non-hedge derivatives are classified as held for trading and recognized at fair market value with changes in fair market value being recorded through earnings. During 2013, there were losses of $7.8 million (2012 – $3.2 million loss) recorded in net earnings.

FAIR VALUE

Fair value of financial instruments and derivatives is determined by reference to quoted bid or asking price, as appropriate, in active markets at reporting dates. In the absence of an active market, the Corporation determines fair value by using valuation techniques that refer to observable market data or estimated market prices. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, ENMAX gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level I) and the lowest priority to unobservable inputs (Level III), as applicable.

Level Determination and Classifications

The Level I, II and III classifications in the fair value hierarchy used by the Corporation are defined as follows:

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange and the Natural Gas Exchange.

Level II

Fair values are determined using inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly.

Fair values are determined using inputs including interest rate yield curves, forward market rates, quoted commodity prices or credit spreads that are readily observable and reliable or for which unobservable inputs are deemed to be insignificant to the fair values that are categorized as Level II.

Commodity contracts' fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability. Level II fair values include those determined using pricing applications for creating power curves where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets.

Interest rate swap contract fair values falling within the Level II fair values include those determined by using a benchmark index and applying that index to the notional debt outstanding.

Level III

The fair values are determined using significant unobservable data or inputs.

In rare circumstances, ENMAX enters into commodity transactions with non-standard features for which market-observable data are not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data.

FAIR VALUES OF THE CORPORATION'S FINANCIAL ASSETS AND LIABILITIES

As at December 31, 2013 *(millions of dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (1) (LEVEL II)	Significant Unobservable Inputs (2) (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	–	27.1	11.1	38.2
Foreign currency forward contracts	–	6.9	–	6.9
Interest rate swap	–	10.9	–	10.9
Financial assets total	–	44.9	11.1	56.0
Financial liabilities measured at fair value:				
Energy trading forward contracts	–	41.4	–	41.4
Foreign currency forward contracts	–	–	–	–
Interest rate swap	–	35.5	–	35.5
Financial liabilities total	–	76.9	–	76.9
Net risk management assets (liabilities)	–	(32.0)	11.1	(20.9)

(1) Excludes financial assets and liabilities where carrying value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities).
(2) Market-observable data are not available. Fair values are determined using valuation techniques.

FAIR VALUES OF THE CORPORATION'S FINANCIAL ASSETS AND LIABILITIES

As at December 31, 2012 *(millions of dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (1) (LEVEL II)	Significant Unobservable Inputs (2) (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	0.1	24.5	15.5	40.1
Foreign currency forward contracts	–	9.9	–	9.9
Interest rate swap	–	22.0	–	22.0
Financial assets total	0.1	56.4	15.5	72.0
Financial liabilities measured at fair value:				
Energy trading forward contracts	3.7	30.6	6.0	40.3
Foreign currency forward contracts	–	1.9	–	1.9
Interest rate swap	–	59.7	–	59.7
Financial liabilities total	3.7	92.2	6.0	101.9
Net risk management assets (liabilities)	(3.6)	(35.8)	9.5	(29.9)

(1) Excludes financial assets and liabilities where carrying value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities).
(2) Market-observable data is not available. Fair values are determined using valuation techniques.

The following table summarizes the key factors impacting the change in the fair value of the Corporation's Level III net risk management assets and liabilities separately by source of valuation during the year:

CHANGE IN FAIR VALUE OF LEVEL III RISK MANAGEMENT ASSETS AND LIABILITIES

(millions of dollars)	Hedges
Net risk management assets as at December 31, 2012	9.5
Changes attributable to:	
Commodity price changes	7.8
New contracts that entered	–
Contracts settled	(0.4)
Transfers in/out of Level III	(5.8)
Net risk management assets at December 31, 2013	11.1
Total change in fair value included in OCI	(1.6)
Total change in fair value included in pre-tax earnings	–

NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

Cash, cash equivalents and restricted cash are recorded at fair market value. Fair values for accounts receivable, short-term debt, accounts payable and accrued liabilities are not materially different from their carrying amounts due to their short-term nature.

The fair value of the Corporation's long-term debt was estimated based on quoted market prices for the same or similar debt instruments. When such information was not available, future payments of interest and principal were discounted at estimated interest rates that were made available to ENMAX for comparable credit-rated entities to the Corporation.

On September 30, 2013, the Series 2 private debenture was repaid, prior to maturity on April 2014, with cash consideration from the second and final part of the arrangement with Capital Power LP (CPLP) for the sale of a 50 per cent interest in Shepard Energy Centre (Shepard). Refer to Note 9 for additional information. ENMAX incurred interest of $7.0 million and a redemption premium penalty of $4.9 million as a result of early redemption.

CARRYING AMOUNTS AND FAIR VALUES OF LONG-TERM DEBT

As at December 31,		2013		2012
(millions of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt [(1)], consisting of:				
Debentures, with remaining terms of				
Less than 5 years	**34.0**	**35.4**	47.0	49.8
6 – 10 years	**122.4**	**132.4**	135.4	150.4
11 – 15 years	**14.4**	**16.1**	7.9	9.4
16 – 20 years	**187.1**	**205.6**	138.3	162.3
21 – 25 years	**557.6**	**571.6**	499.3	565.1
Private debentures				
Series 1 (6.15%)	**298.2**	**338.8**	297.8	345.2
Series 2 (5.85%)	**–**	**–**	249.5	260.8
Non-recourse term financing Kettles Hill Wind Farm (Kettles) and Calgary Energy Centre (CEC)	**220.5**	**207.2**	229.3	219.8
Promissory note	**4.8**	**4.9**	5.0	5.3
	1,439.0	**1,512.0**	1,609.5	1,768.1

(1) Includes current portion of $63.7 million (December 31, 2012 – $59.7 million). Maturity dates range from June 2014 to June 2038.

5. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

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

REGULATORY ASSETS AND LIABILITIES

As at December 31, *(millions of dollars)*	2013	2012
Regulatory assets		
Accounts receivable: purchased power variances (Note a)	**41.5**	21.7
Distribution assets: inter-company profit on underground residential development (Note b)	**38.4**	39.5
Other regulatory assets (Note c)	**42.2**	16.0
Total regulatory assets	**122.1**	77.2
Regulatory liabilities		
Other regulatory liabilities (Note d)	**1.9**	3.3
Total regulatory liabilities	**1.9**	3.3

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 returned to customers as a result of the rate-setting process.

(a) Purchased power variances

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. ENMAX Power 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 represents the excess of actual over forecast purchased power costs. In the absence of rate regulation, GAAP would require that actual purchased power costs be recognized as an expense when incurred. In this case, operating results for 2013 would have been $19.8 million lower (2012 – $48.2 million higher). The regulatory assets are included in accounts receivable.

(b) INTER-COMPANY PROFIT ON UNDERGROUND RESIDENTIAL DEVELOPMENT

Distribution assets for the regulated operations of ENMAX Power include intercompany profit relating to construction work performed by an ENMAX subsidiary. Such profit is deemed for regulatory purposes 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, GAAP would require that intercompany profits be eliminated upon consolidation. If these intercompany profits had been eliminated, the impact on earnings for 2013 would be an increase of $1.1 million (2012 – $0.5 million reduction) representing the profit or loss on these services. The balances for PPE and retained earnings at December 31, 2013, would be further reduced by $38.4 million (December 31, 2012 – $39.5 million reduction).

(c) OTHER REGULATORY ASSETS

Other regulatory assets primarily relate to the Alberta Utilities Commission (AUC) flow-through items and other costs that will be collected from customers via future rates such as access service charges. Timing of decision on collection of these items can result in significant fluctuation in balances from year to year.

(d) OTHER REGULATORY LIABILITIES

Other regulatory liabilities primarily relate to items that will be refunded to customers via future rates.

For certain 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 ENMAX Power 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 period for recovery through future rates or disagree with the proposed recovery period.

OTHER ITEMS AFFECTED BY RATE REGULATION

Current regulations exclude the Corporation's transmission, distribution and rate-regulated electricity sales earnings from corporate income taxes, although rate-regulated electricity sales are subject to PILOT. Accordingly, ENMAX Power has not recognized current or future corporate income taxes on tax exempt earnings. In the event regulations change, it would be expected that when these amounts became payable, they would be recovered through future rate revenues.

Gains and losses on the disposal and retirement of regulated depreciable assets are deferred and amortized over the estimated remaining service life of similar 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 GAAP 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 amount deferred from current period earnings for the year ended December 31, 2013, was an $11.5 million loss (2012 – $5.4 million loss) representing the gains and losses on disposals and retirements of regulated assets.

6. INCOME TAXES

RECONCILIATION OF INCOME TAX EXPENSE

Year ended December 31, (millions of dollars)	2013	2012
Earnings before income taxes from continuing operations	171.4	224.0
Income not subject to taxes	(201.6)	(178.2)
	(30.2)	45.8
Federal and provincial tax rate	25.0%	25.0%
Expected income tax expense	(7.5)	11.4
Non-deductible expenses	3.2	1.1
Adjustment for future tax reversal and other estimate revisions	2.3	(4.1)
Income taxes on continuing operations	(2.0)	8.4

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

FUTURE INCOME TAX ASSET AND LIABILITY

As at December 31, (millions of dollars)	2013	2012
Future income tax asset:		
PPAs [(1)]	11.3	22.7
PPE-differences in net book value and undepreciated capital	4.8	(4.8)
Cumulative eligible capital	6.1	6.5
Other	0.1	4.6
Non-capital loss carry-forwards	45.9	38.5
Unrealized derivative	4.0	0.1
OCI	(4.5)	0.6
	67.7	68.2
Less current portion	(8.7)	(7.2)
	59.0	61.0
Future income tax liability:		
PPE-difference in net book value and undepreciated capital cost	103.0	89.4
PPAs	20.7	17.1
Non-capital loss carry-forwards	(12.6)	(12.6)
OCI	(2.8)	(1.1)
Mark-to-market liability	(1.1)	(3.0)
Other	(6.6)	(1.6)
	100.6	88.2
Less current portion	(0.5)	(3.4)
	100.1	84.8
Net future income tax liability	(32.9)	(20.0)

(1) Under PILOT, 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.

As at December 31, 2013, the Corporation has non-capital loss carry-forwards that will be used to offset taxes in future years. These non-capital loss carry-forwards expire as follows:

NON-CAPITAL LOSS CARRY FORWARD

(millions of dollars)	2013
2027	2.1
2028	18.9
2029	22.5
2030	6.3
2031	2.3
2032	7.3
2033	48.1
	107.5

7. OTHER ASSETS AND LIABILITIES

As at December 31, *(millions of dollars)*	2013	2012
Other current assets		
Hedge instruments	19.7	15.6
Non-hedge derivatives	9.9	11.9
Prepaid expenses	12.3	16.0
Inventory	0.7	2.3
	42.6	45.8
Other long-term assets		
Hedge instruments	18.3	23.5
Non-hedge derivatives	8.1	21.0
Restricted cash	8.4	8.9
Shares in other companies	0.1	0.2
Prepaid expenses	3.6	4.3
Long-term accounts receivable	9.2	0.3
Other	9.3	4.9
	57.0	63.1
Other current liabilities		
Hedge instruments	19.6	19.8
Non-hedge derivative	9.4	9.4
Deposits	18.6	18.3
Deferred revenue	5.2	11.8
	52.8	59.3
Other long-term liabilities		
Hedge instruments	22.8	40.5
Non-hedge derivative	25.1	32.2
Long-term payables	8.0	9.6
Deferred revenue	4.8	4.3
	60.7	86.6

8. RESTRICTED CASH

Other current assets include restricted cash and cash equivalents of $0.5 million (2012–$3.6 million) relating to margin posted with a financial institution. This margin is required as a result of the Corporation's commodity trading activity.

Other long-term assets include restricted cash and cash equivalents of $8.4 million (2012–$8.9 million), relating to a debt servicing obligation on a non-recourse financing arrangement (see Note 15).

9. ASSETS HELD FOR SALE

On February 28, 2013 the Corporation sold a 25 per cent interest in Shepard to CPLP. This was the first of a two-part purchase and sale arrangement entered into on December 5, 2012. On September 30, 2013, CPLP completed the second and final part of the arrangement and purchased an additional 25 per cent interest in Shepard.

On April 8, 2013 ENMAX entered into an agreement to sell ENMAX Envision Inc. (Envision), its high-speed data communications subsidiary, which operates a fibre-optic network that provides large bandwidth solutions to Calgary businesses. On April 30, 2013 ENMAX sold Envision to Shaw Communications Inc. for net cash consideration of $221.9 million. Transaction costs related to the sale totalled $5.7 million. The net gain on sale of Envision was $175.9 million. The net assets of Envision sold consisted of cash of $0.4 million, total assets other than cash of $47.5 million, and total liabilities of $7.6 million. From December 31, 2012 until April 30, 2013, the assets and liabilities of Envision were reclassified to assets and liabilities held for sale on the consolidated balance sheets, and its operating results are included in net earnings from discontinued operations on the consolidated statements of earnings and comprehensive income.

ASSETS AND LIABILITIES HELD FOR SALE

As at December 31, (millions of dollars)	2013	2012
ASSETS		
Accounts receivable	–	3.2
Other current assets	–	0.3
PPE (1)	–	553.1
Intangible assets	–	18.7
Other long-term assets	–	0.3
TOTAL ASSETS	–	575.6
LIABILITIES	–	
Accounts payable and accrued liabilities	–	2.1
Other current liabilities	–	1.7
Other long-term liabilities	–	5.3
Asset retirement obligations	–	0.4
TOTAL LIABILITIES	–	9.5

(1) PPE at December 31, 2012 included Shepard costs of $510.1 million. Intangible assets at December 31, 2012, include Shepard related costs of $18.6 million. Remaining balance relates to Envision.

NET EARNINGS FROM DISCONTINUED OPERATIONS

Year ended December 31, (millions of dollars)	2013	2012
REVENUE		
Contractual services	8.7	28.8
Other	0.2	0.5
TOTAL REVENUE	8.9	29.3
COST OF SERVICES PROVIDED		
Contractual services	1.5	4.4
OM&A	2.3	10.5
COST OF SERVICES PROVIDED	3.8	14.9
Amortization	1.8	4.8
Interest	0.1	0.2
NET EARNINGS FROM DISCONTINUED OPERATIONS [1]	3.2	9.4

(1) Net earnings from discontinued operations relates to Envision.

10. PROPERTY, PLANT AND EQUIPMENT

As at December 31, 2013 (millions of dollars)	Cost	Accumulated Amortization	Net Book Value
Transmission, distribution and substation equipment	2,024.7	(577.6)	1,447.1
Generation facilities and equipment	1,040.1	(218.6)	821.5
Construction in progress	922.5	–	922.5
Buildings and site development	208.9	(65.9)	143.0
Tools, systems and equipment	93.9	(65.4)	28.5
Land	34.5	–	34.5
Capital spares and other	33.6	–	33.6
Vehicles	32.8	(12.7)	20.1
	4,391.0	(940.2)	3,450.8
Government grants	(20.0)	2.3	(17.7)
CIAC	(509.4)	98.9	(410.5)
	3,861.6	(839.0)	3,022.6

As at December 31, 2012 (millions of dollars)	Cost	Accumulated Amortization	Net Book Value
Transmission, distribution and substation equipment	1,737.6	(540.9)	1,196.7
Generation facilities and equipment	1,002.6	(182.6)	820.0
Construction in progress	812.3	–	812.3
Buildings and site development	198.5	(58.7)	139.8
Tools, systems and equipment	91.8	(58.6)	33.2
Land	32.7	–	32.7
Capital spares and other	32.7	–	32.7
Vehicles	31.2	(11.5)	19.7
	3,939.4	(852.3)	3,087.1
Government grants	(20.0)	1.7	(18.3)
CIAC	(463.7)	89.4	(374.3)
	3,455.7	(761.2)	2,694.5

11. POWER PURCHASE ARRANGEMENTS

Under the Keephills PPA, which was acquired in 2000 and expires December 2020, the Corporation owns the rights to the physical output of two electrical generating units. Under the Battle River PPA, which was acquired in stages from 2006 – 2010, Battle River 3 and 4 expired on December 31, 2013 and Battle River 5 expires in 2020.

As at December 31, 2013 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Battle River	572.0	(278.6)	293.4
Keephills	256.5	(180.4)	76.1
	828.5	(459.0)	369.5

As at December 31, 2012 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Battle River	572.0	(236.7)	335.3
Keephills	256.5	(169.6)	86.9
	828.5	(406.3)	422.2

12. INTANGIBLE ASSETS

As at December 31, 2013 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Computer systems	272.9	(191.6)	81.3
Renewable energy certificates and water licenses	12.4	(7.5)	4.9
Customer lists and contracts	20.0	(17.9)	2.1
Land easements, rights and lease options	3.1	(2.7)	0.4
Work in progress	35.6	–	35.6
	344.0	(219.7)	124.3

As at December 31, 2012 *(millions of dollars)*	Cost	Accumulated Amortization	Net Book Value
Computer systems	245.9	(173.1)	72.8
Renewable energy certificates and water licenses	12.4	(6.1)	6.3
Customer lists and contracts	20.0	(15.8)	4.2
Land easements, rights and lease options	3.2	(2.7)	0.5
Work in progress	32.5	–	32.5
	314.0	(197.7)	116.3

13. EMPLOYEE FUTURE BENEFITS

The Corporation has a registered pension plan that substantially covers all employees and includes both DB and 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 ITA. The supplemental pension plan benefits do not automatically increase. In addition, the Corporation provides employees with 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, up to age 65.

Total cash payments for employee future benefits for 2013, consisting of cash contributed by the Corporation 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 $29.1 million (2012 – $16.7 million).

For the year ended December 31, 2013, the total expense for the DC provisions of the plan is $8.5 million (2012 – $8.4 million).

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

DB PROVISION, INCLUDING SUPPLEMENTAL PENSION PLAN AND POST-RETIREMENT NON-PENSION BENEFIT PLAN

Years ended December 31,
(millions of dollars)

	2013		2012	
	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Change in benefit obligation:				
Benefit obligation, beginning of year	273.7	11.1	259.5	9.9
Current service cost	8.7	1.0	7.2	0.9
Employee contributions	2.8	–	2.7	–
Benefits paid	(16.1)	(0.6)	(17.5)	(0.6)
Interest cost	11.0	0.4	11.0	0.4
Non-investment	(0.5)	–	(0.3)	–
Experience gain (loss)	(11.5)	(0.7)	11.1	0.5
Benefit obligation, end of year	268.1	11.2	273.7	11.1
Change in plan assets:				
Plan assets at market-related value, beginning of year	202.1	–	192.5	–
Employer contributions	19.4	0.6	7.8	0.6
Employee contributions	2.8	–	2.7	–
Benefits paid	(16.1)	(0.6)	(17.5)	(0.6)
Non-investment expenses	(0.5)	–	(0.3)	–
Return on plan assets	13.5	–	12.4	–
Acquisitions and divestitures	–	–	0.1	–
Experience loss	2.6	–	4.4	–
Plan assets at market-related value, end of year	223.8	–	202.1	–
Deferred investment gain	12.3	–	4.0	–
Plan assets at fair value, end of year	236.1	–	206.1	–
Funded status-plan deficit	(32.0)	(11.2)	(67.6)	(11.1)
Unamortized past service cost	–	(0.6)	–	(0.6)
Unamortized experience losses	64.5	2.1	94.9	2.9
Accrued benefit asset (liability)	32.5	(9.7)	27.3	(8.8)

Plan assets at December 31, 2013, consist of Canadian equity securities of 30 per cent (2012 – 30 per cent), foreign equity securities of 31 per cent (2012 – 31 per cent), long-term fixed-income securities of 37 per cent (2012 – 38 per cent) and cash and short-term securities of two per cent (2012 – one per cent).

NET BENEFIT COST

Years ended December 31,	2013		2012	
(millions of dollars)	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Current service costs	8.7	0.9	7.1	0.9
Interest cost	11.0	0.4	11.0	0.4
Actual return on assets	(24.4)	–	(15.9)	–
Actuarial gains	(11.5)	(0.7)	11.1	0.5
Difference between expected and actual return	10.9	–	3.5	–
Difference between recognized and actual actuarial gains	19.5	0.8	(2.7)	(0.4)
Difference between amortization of past service costs and actual plan	–	–	–	(0.1)
Net benefit plan expense	14.2	1.4	14.1	1.3

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

SIGNIFICANT WEIGHTED-AVERAGE ACTUARIAL ASSUMPTIONS

Years ended December 31,	2013		2012	
(%)	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Accrued benefit obligation:				
Discount rate	4.50	4.50	4.00	4.00
Rate of compensation increase	6.5	n/a	3.25	3.50
Health care cost trend rate for next year	n/a	8.00	n/a	8.00
Decreasing gradually to 5% in the year	n/a	2020	n/a	2020
Benefit cost:				
Discount rate	4.00	3.75	4.25	4.00
Expected long-term rate of return on plan assets	6.5	n/a	6.5	n/a
Rate of compensation increase	3.25	3.50	3.50	3.50
Health care cost trend rate for next year	n/a	8.00	n/a	9.50
Decreasing gradually to 5% in the year	n/a	2020	n/a	2021

The per capita cost of covered dental benefits was assumed to increase by 4.5 per cent per year (2012 – 5.0 per cent).

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 2013:

ONE-PERCENTAGE-POINT CHANGE IN ASSUMED HEALTH CARE COST TREND RATE

(millions of dollars)	1% increase	1% decrease
Increase (decrease) in service cost for year ended December 31	–	–
Increase (decrease) in interest cost for year ended December 31	–	–
Increase (decrease) in accrued benefit obligation at December 31	0.3	(0.3)

14. SHORT-TERM DEBT

The Corporation has unsecured credit facilities amounting to $1,150.0 million (December 31, 2012 – $1,150.0 million) to fund general operating requirements and to provide liquidity support for commercial paper and commodity marketing programs. Combined, all of the facilities encompass $900.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities. As at December 31, 2013, $273.9 million (December

31, 2012 – $355.0 million) of operating facilities and $30.0 million (December 31, 2012 – $30.0 million) of syndicated facilities were used in support of outstanding letters of credit (see Note 19).

At December 31, 2013 the Corporation had no short-term debt (2012–$165.9 million at weighted average rate of 1.31 per cent).

15. LONG-TERM DEBT

As at December 31, (millions of dollars)	2013	Weighted Average Interest Rates	2012	Weighted Average Interest Rates
City debentures [1], with remaining terms of:				
Less than 5 years	**34.0**	**4.20%**	47.0	4.56%
5 – 10 years	**122.4**	**4.39%**	135.4	4.43%
10 – 15 years	**14.4**	**4.85%**	7.9	5.00%
15 – 20 years	**187.1**	**4.57%**	138.3	4.61%
20 – 25 years	**557.6**	**3.93%**	499.3	4.17%
Private debenture [1]	**298.2**	**6.15%**	547.3	6.01%
Non-recourse financing	**220.5**	**6.45%**	229.3	6.38%
Promissory note	**4.8**	**5.00%**	5.0	5.00%
	1,439.0		1,609.5	
Less: current portion	**63.7**		59.7	
	1,375.3		1,549.8	

(1) Unsecured debentures.

CITY DEBENTURES

Debentures were initially issued by The City on behalf of the CES pursuant to City bylaw 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 continues to administer the new and existing debentures on behalf of the Corporation.

On June 15, 2013, the Corporation obtained $140.6 million of 5-, 10-, 20- and 25-year debentures from The City through arrangements with the Alberta Capital Finance Authority (ACFA) (June 2012–$143.4 million in 5-, 10-, 20- and 25-year debentures). Interest on the debentures is compounded semi-annually as follows: $3.8 million, which matures in June 2018, at 1.68 per cent; $2.6 million, maturing in June 2023, at 2.50 per cent; $11.6 million, maturing in June 2033, at 3.25 per cent; and the remaining $122.6 million of the debt, which matures in June 2038, at 3.32 per cent. The funds were used for capital expenditures in ENMAX Power.

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 per cent on the average monthly outstanding debenture balance held by The City on behalf of the Corporation.

PRIVATE DEBENTURES

No private debentures were issued in 2013 or 2012. On September 30, 2013 the debentures for $250.0 million were repaid. The remaining $300.0 million of private debentures outstanding at December 31, 2013 bear interest at rate of 6.15 per cent, payable semi-annually and mature on June 19, 2018.

NON-RECOURSE FINANCING

The non-recourse financing represents the Corporation's loans, through subsidiaries, for the Kettles and CEC projects. The balance outstanding on the Kettles debt at December 31, 2013, was $19.9 million (2012–$19.8 million), which bears interest at a fixed rate of 5.86 per cent, payable monthly, maturing in December 2016. The balance outstanding on the CEC debt at December 31, 2013, was $200.6 million (2012 – $209.5 million), which was effectively fixed to an interest rate of 6.74 per cent using an interest rate swap. The CEC debt is payable quarterly and matures in September 2026.

As at December 31, 2013 *(millions of dollars)*	Principal Outstanding	Maturity Date	Average Interest Rate
CEC	200.6	Sep. 2026	6.51%
Kettles	19.9	Dec. 2016	5.86%
	220.5		6.45%
Less: current portion	9.5		
	211.0		

As at December 31, 2012 *(millions of dollars)*	Principal Outstanding	Maturity Date	Average Interest Rate
CEC	209.5	Sep. 2026	6.43%
Kettles	19.8	Dec. 2016	5.86%
	229.3		6.38%
Less: current portion	8.8		
	220.5		

PROMISSORY NOTE

The promissory note was issued in the fourth quarter of 2006 and represents an amortizing loan from The Board of Trustees of Westwind School Division No. 74, acting as agent for the Wind Participation Consortium, which is comprised of three school divisions. The 20-year note, in the amount of $6.3 million, bears interest at a fixed rate of five per cent and is repayable in monthly instalments. The Corporation provided a fixed charge over two wind turbines located at Taber, Alberta, as security for the loan. Concurrent with execution of the loan, WPC executed a 20-year electricity services agreement with ENMAX Energy.

PRINCIPAL REPAYMENTS

The required repayments of principal on the long-term debt at December 31, 2013 are as follows:

REQUIRED REPAYMENTS OF PRINCIPAL

As at December 31 *(millions of dollars)*	2013
2014	63.2
2015	62.3
2016	77.0
2017	58.2
2018	359.1
Therefore	819.2

As at December 31, 2013, the Corporation is in compliance with its financial covenants related to debt classified as long-term debt on the consolidated balance sheet.

16. ASSET RETIREMENT OBLIGATION

The Corporation recognizes its obligation to retire certain tangible long-lived assets, whereby the fair value of 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, any changes in the amount or timing of the underlying future cash flows are recognized as a change in the carrying amount of the liability for an asset retirement obligation and the related asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. A gain or loss may be incurred upon settlement of the liability.

At December 31, 2013, the Corporation has asset retirement obligations relating to the following project generating assets: McBride, Taber Wind Farm (Taber), Crossfield Energy Centre (Crossfield), Kettles and CEC. The accretion expense on these assets is included in the amortization line item on the consolidated statement of earnings. The change in the carrying amount of the asset retirement obligations is disclosed in the table below:

CHANGE IN CARRYING AMOUNT OF ASSET RETIREMENT OBLIGATIONS

(millions of dollars)	2013	2012
Balance, beginning of year	14.4	13.6
Liabilities incurred in the current period	–	–
Accretion expense	1.0	0.8
Balance, end of year	15.4	14.4

The expected remediation liability and timing for each undiscounted asset is disclosed in the table below, based on a credit adjusted risk-free discount rate of 6.0 per cent and a rate of inflation of 2.1 per cent:

EXPECTED REMEDIATION AND TIMING

(millions of dollars)	Amount	Date
McBride	47.8	September 2057
Taber	32.4	December 2057
Kettles	26.2	May 2071
Crossfield	10.4	December 2048
CEC	29.6	March 2043

17. SHARE CAPITAL

(millions of dollars, except share amounts)	Number of Shares	Amount
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Balance, December 31, 2012 and 2013:		
Issued on incorporation	1	–
Issued on transfer of net assets from CES *(Note 1)*	1	278.2
Issued on transfer of billing and customer care assets from The City in 2001	1	1.9
Balance, December 31, 2012 and 2013	3	280.1

18. ACCUMULATED OTHER COMPREHENSIVE INCOME

As at December 31, *(millions of dollars)*	2013	2012
Unrealized losses on available-for-sale financial assets	**(0.1)**	(0.1)
Unrealized gains (losses) on derivatives designated as cash flow hedges	**(6.2)**	(19.5)
Accumulated other comprehensive income (losses), including a future income tax expense of $1.7 million (2012 – recovery of $1.7 million)	**(6.3)**	(19.6)

19. COMMITMENTS AND CONTINGENCIES

PROPERTY, PLANT AND EQUIPMENT

The Corporation is committed to major capital expenditures over the next five years and thereafter, with minimum annual payments (including cancellation costs) as follows:

MAJOR CAPITAL COMMITMENTS OVER THE NEXT FIVE YEARS

(millions of dollars)	
2014	56.6
2015	1.1
2016	0.9
2017	0.9
2018	0.9
Thereafter	20.7

OBLIGATIONS UNDER OTHER AGREEMENTS

The Corporation rents premises, vehicles and equipment under multiple lease contracts with varying expiration dates.

The Corporation is obligated to make monthly payments in return for the output from PPAs and other tolling arrangements, based on normal operating conditions adjusted for inflation, other than in the event of a forced outage.

The Corporation commits to the purchase of renewable energy certificates and carbon offset credits. The Corporation commits to long-term service arrangements on certain generating assets.

The aggregated minimum payments under these arrangements over the next five years are as follow:

AGGREGATE PAYMENTS UNDER OTHER AGREEMENTS

(millions of dollars)	
2014	42.1
2015	20.1
2016	11.1
2017	9.5
2018	8.9
Therefore	16.6

REGULATORY

The Corporation, along with other electrical transmission and 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.

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 operating results or financial position of the Corporation.

POWER PURCHASE ARRANGEMENTS

The facilities covered under PPAs were subject to outages and operational issues during the year. The PPA owners and ENMAX often differ in opinion as to who should bear the costs arising from these events. Although there can be no assurance that these disputes will be resolved in the Corporation's favour, the Corporation does not believe that the outcome of these disputes will have a material adverse affect on the financial position of the Corporation.

INCOME TAX

Alberta Finance, Tax and Revenue Administration is responsible for assessing the income tax returns filed under the PILOT regulation of the EUA, which became effective January 1, 2001.

The Corporation regularly reviews the potential for adverse outcomes in respect of tax matters and believes it has adequate provisions for these tax matters. Tax provisions are adjusted, positively or negatively, for changes in estimates and assessments by tax authorities in the period in which they are more likely than not to have an impact on the financial results. Although there can be no assurance that these disputes will be resolved in the Corporation's favour, the Corporation does not believe that the outcome of these disputes will have a material adverse affect on the financial position of the Corporation.

ENVIRONMENTAL

Provincial regulations aimed at reducing the levels of Greenhouse Gas (GHG) emissions took effect July 2007. Due to the change of law provisions in ENMAX Energy's PPAs and tolling agreements ENMAX Energy is exposed to the associated compliance costs.

For the year ended December 31, 2013, the consolidated financial statements include a charge to earnings in the amount of $4.1 million (2012 – $20.7 million) included in costs of electricity services provided, relating to estimated compliance costs under the provincial GHG regulations for ENMAX Energy's interests in coal and natural-gas-fired generation facilities through its PPAs and owned assets. The 2013 charge of $4.1 million is net of a partial recovery of payments related to 2009–2011 GHG compliance costs with respect to calculations of GHG emissions for 2009–2011. Compliance payments are due to the Province of Alberta, directly or via plant owners, by June 30 of the year following the compliance year. ENMAX Energy has taken steps, including acquiring qualified offset credits from both its wind-generation assets and purchases on the wholesale market, to mitigate impacts of the GHG regulations.

LETTERS OF CREDIT

In the normal course of operations, letters of credit are issued to facilitate the extension of sufficient credit for counterparties having credit exposure to the Corporation or its subsidiaries. As at December 31, 2013, the Corporation had issued letters of credit amounting to $303.9 million (December 31, 2012 – $385.0 million).

DIRECTOR/OFFICER INDEMNIFICATIONS

Under its bylaws, the Corporation indemnifies individuals who have acted at the Corporation's request to be a director and/or officer of the Corporation and/or one or more of its direct and indirect subsidiaries, to the extent permitted by law, against any and all damages, liabilities, costs, charges or expenses suffered or incurred by the individuals as a result of their service. The claims covered by such indemnifications are subject to statutory or other legal restrictions and limitation periods. The nature of the indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum potential amount it could be required to pay to beneficiaries of such indemnification agreements. The Corporation has purchased various insurance policies to reduce the risks associated with the indemnification.

OTHER INDEMNIFICATIONS

In the ordinary course of business, the Corporation and its subsidiaries enter into contracts which contain indemnification provisions, such as purchase and sale contracts, service agreements, intellectual property licensing agreements, purchases and sales of assets and equipment, joint venture agreements (JVAs), operating agreements and leasing and land use arrangements. In such contracts, the Corporation may indemnify counterparties to the contracts if certain events occur, such as undisclosed liabilities, changes in financial condition and loss caused by the actions of third parties or as a result of litigation or other claims by third parties. These indemnification provisions will vary based upon the contract. In most cases, there are no pre-determined amounts or limits included in these indemnification provisions and the occurrence of contingent events that will trigger payment under them is difficult to predict. Therefore, the maximum potential future amount the Corporation could be required to pay cannot be estimated.

20. CAPITAL MANAGEMENT

The Corporation's objectives when managing capital are threefold: (i) to maintain a flexible capital structure that optimizes corporate liquidity as well as the cost of capital at acceptable risk; (ii) to manage capital in a manner that balances the interests of stakeholders; and (iii) to meet regulatory requirements for certain operations subject to rate regulation.

The Corporation's capital structure consists of net debt and shareholder's equity. Net debt is comprised of long-term debt, including current portions, less cash and cash equivalents.

CAPITAL STRUCTURE

As at December 31, *(millions of dollars)*	2013	2012
Long-term debt [1]	**1,439.0**	1,609.5
Less: cash and cash equivalents	**80.6**	45.5
Net debt	**1,358.4**	1,564.0
Shareholder's equity	**2,460.2**	2,161.9
Total capital	**3,818.6**	3,725.9

(1) Includes current portion of $63.7 million (2012 - $59.7 million). Maturity dates range from June 2014 to June 2038.

The calculation of earnings before interest, income taxes and depreciation (EBITDA) is a measure whose nearest GAAP measure is net earnings with the reconciliation between the two measures set out in the following schedule:

EBITDA

As at December 31, (millions of dollars)	2013	2012
Adjusted EBITDA	377.7	443.0
Less: EBITDA from discontinued operations	5.1	14.4
Standardized EBITDA	372.6	428.6
Deduct: Amortization	168.1	164.4
EBIT	204.5	264.2
Deduct: Interest expense	33.1	40.2
Deduct: Income taxes	(2.0)	8.4
Net earnings from continuing operations	173.4	215.6

In addition, the Corporation monitors its capital using various ratios including (i) long-term debt to total capitalization; and (ii) EBITDA to interest expense.

Debt to total capitalization is calculated as long-term debt, including the current portion of long-term debt, divided by total capital and is also a calculation used in certain of the Corporation's debt covenants.

The calculation obtained by using interest expense and standardized EBITDA from the above table is substantially the same as the interest coverage ratio covenant set out in the Corporation's credit facilities.

The Corporation manages its consolidated capital structure through prudent levels of borrowing, cash flow forecasting, and working capital management. These capital management policies, which remain unchanged from prior periods, provide access to capital at a reasonable cost while maintaining investment-grade credit ratings. DBRS and Standard & Poor's corporate credit ratings for the Corporation are A (low) (stable trend) and BBB+ (stable), respectively.

As at December 31, 2013, the Corporation is in compliance with its financial maintenance covenants on its outstanding long-term debt.

21. INTEREST

As at December 31, (millions of dollars)	2013	2012
Interest on long-term debt	88.8	86.0
Short-term interest and other financing charges	2.2	4.5
Less: capitalized interest	(57.9)	(50.3)
	33.1	40.2

22. JOINT VENTURE INVESTMENTS

In 2002, the Corporation entered into a JVA with Vision Quest Windelectric Inc., to build and operate 114 wind turbines in southern Alberta (McBride). The turbines began generating electricity in 2003, and the Corporation has a 50 per cent ownership interest. The Corporation has also agreed to purchase 100 per cent of the output from the wind farm under a 20-year PPA.

In 2010, the Corporation entered into a JVA with SNC-Lavalin Constructions Inc. (SNC-Lavalin) to design and construct certain portions of the West LRT in Calgary. Construction was complete and the West LRT was operational as of December 10, 2012.

In 2012, CPLP agreed to purchase a 50 per cent interest in Shepard and enter into a JVA to construct and operate the facility. The sale of the 50 per cent interest in Shepard was completed September 30, 2013.

PROPORTIONATE SHARE OF THE JOINT VENTURES' NET ASSETS

For the year ended December 31,				2013				2012
(millions of dollars)	Shepard	McBride	SNC-Lavalin	Total	Shepard	McBride	SNC-Lavalin	Total
Cash and cash equivalents	7.4	–	0.6	8.0	–	–	4.9	4.9
Accounts receivable	6.8	0.2	0.1	7.1	–	0.6	4.7	5.3
Other current assets	6.2	0	–	6.2	–	–	–	–
PPE	745.0	33.4	–	778.4	–	35.7	–	35.7
Other long term assets	5.0	–	–	5.0	–	–	–	–
Accounts payable	(25.8)	(0.3)	–	(26.1)	–	(0.2)	(1.5)	(1.7)
Other current liabilities	–	–	–	–	–	–	(3.2)	(3.2)
Other long-term liabilities	–	(4.3)	–	(4.3)	–	(4.0)	–	(4.0)
Proportionate share in net assets of joint ventures	774.6	29.0	0.7	774.3	–	32.1	4.9	37.0

PROPORTIONATE SHARE OF THE JOINT VENTURES' CASH FLOWS

For the year ended December 31,				2013				2012
(millions of dollars)	Shepard	McBride	SNC-Lavalin	Total	Shepard	McBride	SNC-Lavalin	Total
Operating activities	–	4.5	(4.3)	0.2	–	4.9	(1.2)	3.7
Investing activities	273.5	–	–	273.5	–	–	–	–
Financing activities	(266.1)	(4.5)	–	(270.6)	–	(4.9)	–	(4.9)
Proportionate share in the increase/(decrease) in cash and cash equivalents of joint venture	7.4	–	(4.3)	3.1	–	–	(1.2)	(1.2)

PROPORTIONATE SHARE OF THE JOINT VENTURES' NET EARNINGS

For the year ended December 31,				2013				2012
(millions of dollars)	Shepard	McBride	SNC-Lavalin	Total	Shepard	McBride	SNC-Lavalin	Total
Earnings								
Revenue	–	7.2	2.8	10.0	–	7.9	13.9	21.8
Cost and expenses	–	(3.1)	(1.6)	(4.7)	–	(3.2)	(11.2)	(14.4)
Amortization	–	(2.3)	–	(2.3)	–	(2.3)	(0.1)	(2.4)
Interest	–	(0.2)	–	(0.2)	–	(0.3)	–	(0.3)
Proportionate share in net earnings of joint ventures	–	1.6	1.2	2.8	–	2.1	2.6	4.7

23. ITEMS NOT INVOLVING CASH

For the year ended December 31, *(millions of dollars)*	2013	2012
Amortization	168.1	164.4
Future income taxes	8.0	3.3
Change in unrealized market value of financial contracts	7.7	3.4
Other	2.5	0.3
	186.3	171.4

24. CHANGE IN NON-CASH WORKING CAPITAL

As at December 31, (millions of dollars)	2013	2012
Accounts receivable	(7.9)	(35.1)
Other current assets	4.6	(0.8)
Accounts payable and accrued liabilities	(126.4)	148.1
Other current liabilities	(6.5)	(0.3)
	(136.2)	111.9

25. RELATED PARTY TRANSACTIONS

ENMAX's related party transactions comprise both revenues from and expenditures to The City. The City is the sole shareholder of the Corporation. Total revenues received from The City for the year ended December 31, 2013, were $121.1 million (2012 – $109.8 million). The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services and billing and customer care services relating to The City's utilities departments. ENMAX has committed to a water supply agreement with The City, to commence upon completion of Shepard, whereby The City will supply a specified amount of water annually to facilitate Shepard operations.

As at December 31, 2013, amounts owing to the Corporation from The City for services provided were $31.2 million (December 31, 2012 – $26.4 million).

Total expenditures for goods and services received from The City for the year ended December 31, 2013, were $137.1 million (2012 – $155.4 million). Most of these expenditures were for local access fees for use of The City's rights-of-way, the cost of which is passed through by ENMAX directly to transmission and distribution customers. The measurement basis used in determining the above values is the contract amount that is considered fair market value; that is, the measurement basis is the same as would be used for a third-party arm's-length transaction.

In 2009, the Corporation entered into a capital lease agreement with The City for the use of its land and building. As at December 31, 2013, the assets under the capital lease were $4.3 million (December 31, 2012 – $4.4 million), and the capital lease obligation was $4.6 million (December 31, 2012 – $4.7 million).

In addition, on June 15, 2013, the Corporation obtained $140.6 million from The City through arrangements with the ACFA to fund ongoing investment relating to the regulated transmission and distribution network in Calgary and the surrounding area. This brings the total amount of debt owed to The City to $915.5 million at December 31, 2013 (December 31, 2012 – $827.8 million). Interest paid for the year ended December 31, 2013, was $37.6 million (2012 – $35.5). Principal payments of $52.9 million were made during the nine months ended December 31, 2013 (2012 – $27.6 million).

Transactions between the Corporation and The City have been recorded at the exchange amounts. Exchange amounts are the amounts as outlined by the contracts in effect between the Corporation and The City.

26. GOVERNMENT GRANTS

On October 7, 2008, the Corporation and The City entered into an infrastructure funding agreement for the construction of the Downtown District Energy Centre (DDEC). Funding of $10.0 million was received by the Corporation from the Government of Alberta and an additional $10.0 million was received from the Government of Canada. The DDEC began operations in 2010, and the grants have been deducted from the carrying amount of the assets in PPE. The grants are being amortized over the life of the asset. For the year ended December 31, 2013, amortization of $0.7 million was recognized on the grants (2012 – $0.6 million).

The Corporation has established the Home Generation Solutions Project to install residential scale renewable systems utilizing photovoltaic or micro-wind technology. The Corporation has entered into a contribution agreement with Climate Change and Emissions Management Corporation to aid with the costs related to this project. For the year ended December 31, 2013, $0.2 million of assistance has been recorded (2012 – $0.7 million).

27. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's presentation.

During the third quarter, there was a reporting segment structure change. Encompass was previously being reported as part of ENMAX Energy and is now included in the Corporate segment. Based on the nature of the services provided by Encompass, it was deemed to be consistent with services provided by this segment. The change in presentation impacts only segment note disclosure, not earnings.

During 2013, the presentation of cash flow provided by operating activities changed. Cash flow provided by operating activities provides detail of net earnings from discontinued operations and gain on sale of subsidiary. The presentation change does not impact the total cash provided by operating activities for December 31, 2012. The change in presentation has been applied to the comparative year.

28. SUBSEQUENT EVENTS

On March 5, 2014 the Corporation declared a dividend of $60.0 million payable to The City in quarterly instalments in 2014.

GLOSSARY OF TERMS

ACFA	Alberta Capital Finance Authority
AcSB	Accounting Standards Board of Canada
AESO	Alberta Electric System Operator
AUC	Alberta Utilities Commission
Board	ENMAX's Board of Directors
CPLP	Capital Power LP
CEC	Calgary Energy Centre
CES	Calgary Electric System
CCEMA	Change and Emissions Management Amendment
CIAC	Contributions in Aid of Construction
Crossfield	Crossfield Energy Centre
DB	Defined Benefit
DC	Defined Contribution
DDEC	Downtown District Energy Centre
EBIT	Earnings before interest and income taxes
EBITDA	Earnings before interest, income tax and depreciation
EPSP	Energy Price Setting Plan
EMS	Environmental Management System
ENMAX	ENMAX Corporation and its subsidiaries
Envision	ENMAX Envision Inc.
ERM	Enterprise Risk Management
ESA	Energy Services Agreements
EUA	Alberta Electric Utilities Act
FBR	Formula-Based Rates
GAAP	Canadian Generally Accepted Accounting Principles
GHG	Greenhouse Gas
GJ	Gigajoule
GWh	Gigawatt hour
IASB	International Accounting Standards Board
ICFR	Internal Control over Financial Reporting
IDC	Interest During Construction
IFRS	International Financial Reporting Standard
ITA	Income Tax Act (Canada)
JVA	Joint Venture Agreement
Kettles	Kettles Hill Wind Farm
LTSA	Long-Term Service Agreement
McBride	McBride Lake Wind Farm
MD&A	Management's Discussion and Analysis
MSA	Market Surveillance Administrator
MW	Megawatt
MWh	Megawatt hour
OCI	Other Comprehensive Income
OM&A	Operations, maintenance and administration
PBR	Performance Based Rates
PILOT	Payment in Lieu of Tax
PPA	Power Purchase Arrangement
PPE	Property, Plant and Equipment
RMC	Risk Management Committee
ROE	Return on Equity
RRO	Regulated Rate Option
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
Shepard	Shepard Energy Centre
Taber	Taber Wind Farm
The City	The City of Calgary
TJ	Terajoule
TransAlta	TransAlta Corporation
URD	Underground Residential Development

ADDITIONAL INFORMATION

ENMAX welcomes questions from stakeholders.
Additional information relating to ENMAX can be found at enmax.com.

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