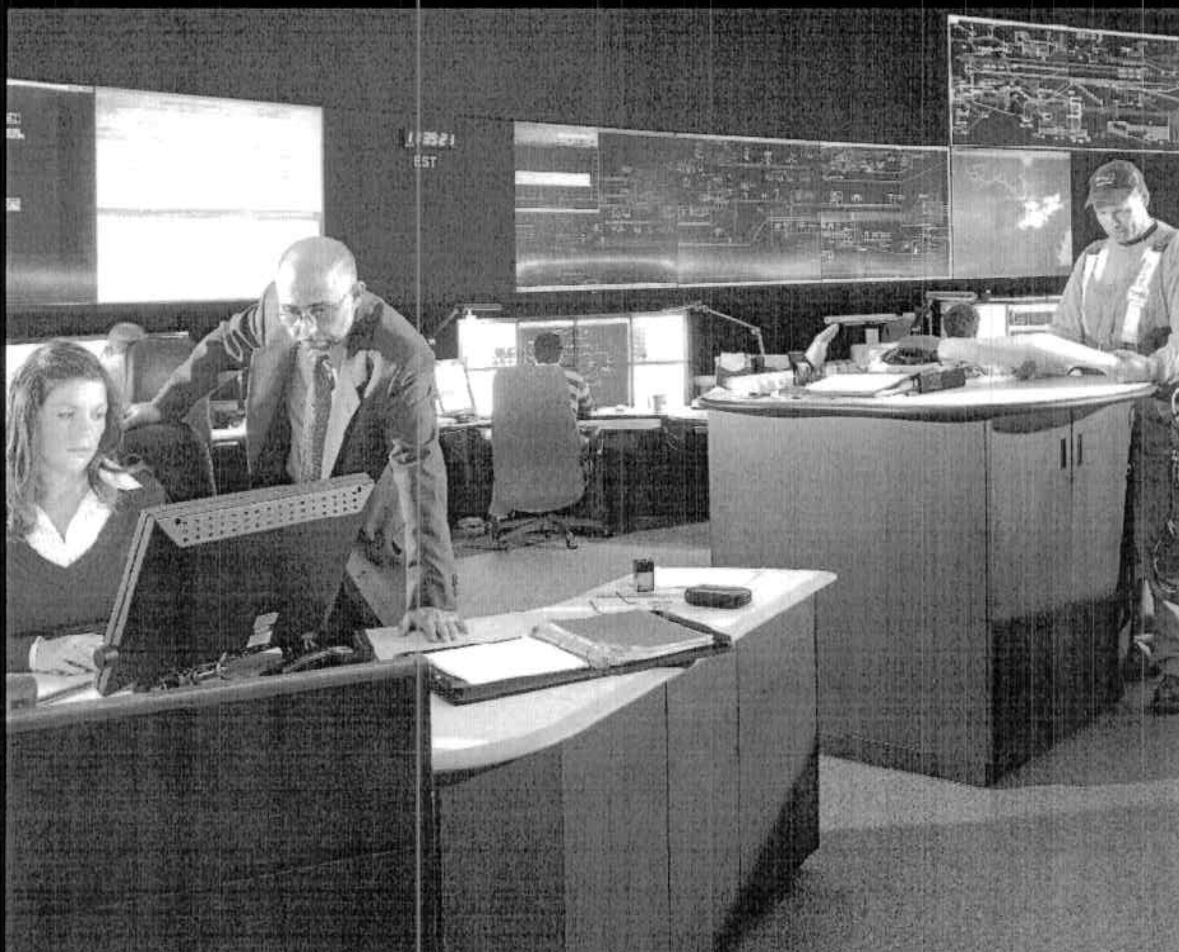
Appendix ‘B’

Financial Information

ANNUAL REPORT 2009

Investing in Ontario's Energy Future

hydro One



Hydro One Inc.

Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom services.

Hydro One Networks Inc.

Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.

Distributes electricity to one of the fastest-growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.

Operates and maintains the generation and distribution assets used to supply electricity to 21 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.

Markets our fibre-optic capacity to business customers. This business represents less than 1% of our total assets.

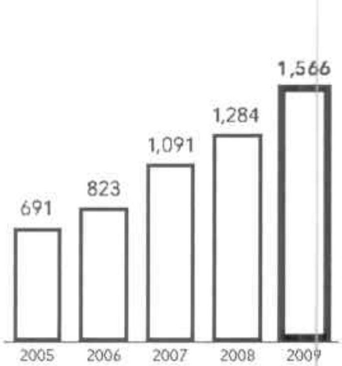
For more than 100 years, Hydro One has connected customers to safe, reliable and cost-effective electricity. Today, we are working to meet Ontario's energy needs for the 21st century.

Consolidated Financial Highlights and Statistics

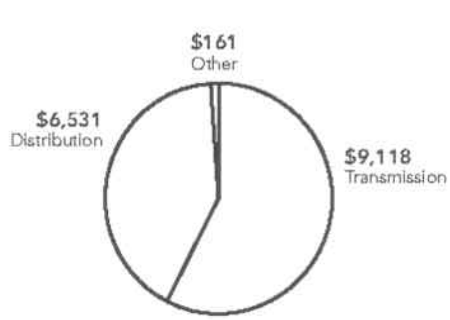
Year ended December 31 (Canadian dollars in millions)	2009	2008	$ Change	% Change
Revenues	**4,744**	4,597	147	3
Purchased power	**2,326**	2,181	145	7
Operating costs	**1,594**	1,513	81	5
Net income	**470**	498	(28)	(6)
Net cash from operations	**892**	1,052	(160)	(15)
Average annual Ontario 60 minute peak demand *(MW)*[1]	**20,798**	21,820	(1,022)	(5)
Distribution units distributed to customers *(TWh)*[1]	**28.9**	29.9	(1.0)	(3)

[1] System-related statistics include preliminary figures for December.

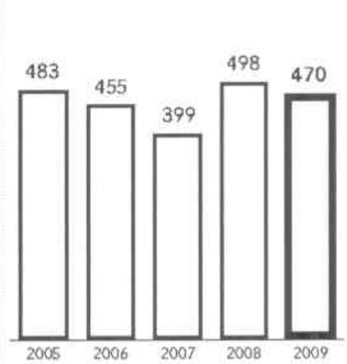
Capital Expenditures
(Canadian dollars in millions)



Total Assets
December 31, 2009 (Canadian dollars in millions)



Net Income
(Canadian dollars in millions)



Letter from the Chair

Fundamental to the Board's role is fostering a commercial culture that increases enterprise value while providing safe, reliable and cost-effective transmission and distribution of electricity.

James Arnett
Chair of the Board of Directors

As the Ontario Energy Board recently noted, Hydro One faces an operating environment that is turbulent and to some extent unknown. In this environment, the Company performed well in 2009.

I will leave it to the President and Chief Executive Officer to report on our results and financial metrics for the year.

Fundamental to the Board of Directors' oversight role is ensuring that Hydro One acts as a commercial enterprise and, to that end, fostering a commercial culture that increases enterprise value for the shareholder while providing safe, reliable and cost effective transmission and distribution of electricity to Ontario's electricity users.

In 2008, the Board adopted a new strategic plan which emphasized this, and in 2009, the Board reviewed it and found it still appropriate.

Key to all of this is ensuring alignment of the organization with the Company's strategic objectives. To accomplish this, the Board has approved a corporate scorecard and short term management incentives based upon performance measures derived from the corporate scorecard. The Human Resources and Public Policy Committee of the Board spent a lot of time and effort during the past year analyzing and refining the corporate scorecard and these measures. The resulting management compensation is described in detail in our Annual Information Form for 2009. The Board determined that of 13 corporate targets, 8 were met or exceeded and 5 were not and accordingly decided, in its discretion, on a 13% reduction from the overall maximum potential payout. On the other hand, the payouts were still significant, reflecting a good overall performance.

Another area where the Board spent more time and effort than usual was in its oversight of the pension plan, primarily by the Audit and Finance Committee. All aspects of the governance and management of the pension plan were reviewed in detail. Meanwhile, the sharp rebound in the financial markets from 2008 resulted in a significant improvement in the plan's position at year end.

In September 2009, the Board considered in detail, and then agreed to, a request from the Government of Ontario to proceed with the planning for a series of major transmission projects in support of the Green Energy Act (GEA). Management is working on the development of those projects. In December, the Company received

2010

Clean Energy Corridor
Construction of the Bruce to Milton Transmission Reinforcement Project will begin in 2010.

2X

Infrastructure
Over the past five years, Hydro One's work program has nearly doubled, principally to refurbish aging infrastructure.

Environmental Assessment approval for the Bruce to Milton Transmission Reinforcement Project, the largest transmission project by the Company in a generation. Construction of the transmission line will begin in 2010.

Meanwhile, the Company completed its largest ever work program both in capital and OM&A. Indeed, over the past five years, the Company's work program has nearly doubled, principally to refurbish aging infrastructure, which is required quite apart from the GEA.

These major capital programs will require continued careful oversight of the Company's operating and financial situation. They will also require that we maintain the Company's strong credit ratings to facilitate the borrowing which will be increasingly required. The Audit and Finance Committee of the Board scrutinizes this from a financial perspective. In addition, the Business Transformation Committee will oversee all matters related to the planning, development and implementation of our GEA projects.

In conclusion, I believe that the Board of Directors performed well in its oversight role during 2009.

I want to thank management, all of our employees, and all my colleagues on the Board of Directors for their dedication and tireless efforts on behalf of both our customers and our shareholder.

James Arnett
Chair of the Board of Directors
Hydro One Inc.

Letter from the President and CEO

It's a pivotal time for Hydro One. Our customers rightfully expect a safe, reliable and cost-effective grid at a time when Ontario's energy sector is undergoing tremendous investment and change.

Laura Formusa
President and Chief Executive Officer

2009 was a year of moving forward for Hydro One. Our Company made progress on multiple projects, embraced new technologies and strengthened relationships as we focused on our core role as stewards of Ontario's electricity transmission grid and largest distribution system.

It's a pivotal time for Hydro One. Our customers rightfully expect a safe, reliable and cost effective grid at a time when Ontario's energy sector is undergoing tremendous investment and change. Our strategy is guided by four key values: health and safety, stewardship, excellence and innovation. These values touch every initiative and inform every decision.

These values serve Ontario well as we continue with the largest program of infrastructure investment and renewal in more than two decades. The move to cleaner, decentralized power sources provides us with the opportunity to rethink our systems of transmission and distribution. Projects across the province are focused on improving the performance of existing assets, relieving internal congestion points and delivering new clean and renewable generation to Ontario homes and businesses. Hydro One is a key enabler of the Green Energy Act (GEA) and is developing an electricity grid that is modern, flexible and smart; one that will contribute to a better environment, and deliver clean, renewable power to and from growing communities.

Our smart meter program surpassed the key milestone of one million smart meters installed, with almost 750,000 meters communicating at a level capable of reliable meter reading. This is one of the largest smart meter deployments by a utility in North America. Our customers will begin to move to time of use pricing in 2010, with full transition expected in 2011.

Hydro One played a leadership role in the technical assessment and acquisition of the 1.8 1.83 GHz spectrum for Smart Grid applications. Our people were leaders in obtaining a dedicated communications spectrum for Smart Grid applications from Industry Canada this was an enormous achievement which will pave the way to our smarter future.

In September, the Government of Ontario asked our Company to proceed with a series of transmission projects in support of the GEA. We began the planning work on several large projects in October and continued our planning of the Northwest Transmission Expansion Project.

In December, we received Environmental Assessment approval for the Bruce to Milton Transmission Reinforcement Project. The project involves constructing a new 180 kilometre double circuit 500 kilovolt transmission line from the Bruce Power Facility to our Milton Switching Station and will enable the delivery of 1,700 MW of renewable generation identified in the area, as well as about 1,500 MW of power from refurbished units at the Bruce Power Facility. We expect to break ground on this project in the first half of 2010.

3,200 MW

RENEWABLE ENERGY

We received Environmental Assessment approval for the Bruce to Milton Transmission Reinforcement Project that will enable approximately 1,700 MW of renewable generation identified in the area, as well as about 1,500 MW of power from refurbished units at the Bruce Power Facility.

1 MILLION

SMART METERS

Our smart meter program surpassed the key milestone of one million smart meters installed.

#1

CORPORATE CITIZEN

In 2009, Hydro One was named Canada's top corporate citizen by *Corporate Knights* magazine.

In 2009, *Corporate Knights* magazine named Hydro One as Canada's top corporate citizen. We were proud to receive that acknowledgement, but we take nothing for granted. I believe a company is not just measured by what they do, but also by how they do it. That's why we continue to focus on building strong relationships with First Nations and Métis communities, as well as all the communities in which we work and live.

We minimize our impact on the environment by examining every piece of our operations for improvement. This year's focus on our fleet of vehicles, which travel more than 100 million kilometres per year, included large initiatives like the introduction of Ontario's first hybrid bucket truck, a rigorous anti idling and driver behaviour policy and the adoption of a vehicle right sizing program to match the right sized vehicle to the right task. Over the last year, we removed 525 metric tonnes of greenhouse gases through these and other initiatives.

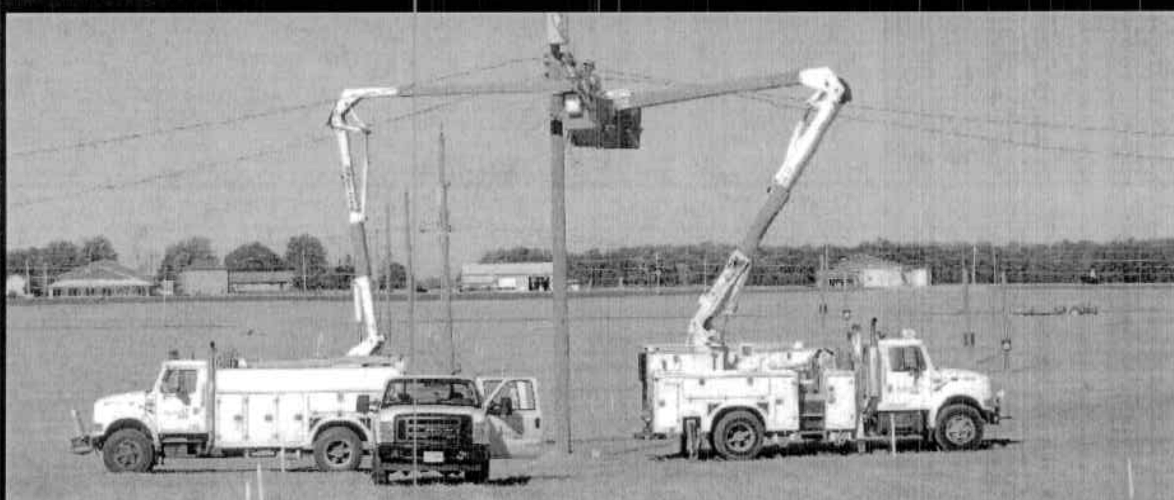
Our partnerships with Ontario's institutions of higher learning are beginning to yield dividends with more and more qualified applicants helping Hydro One meet the human resource challenge we face. More than 30% of staff are eligible to retire within the next five years. We continued to invest in children's active play facilities in communities across Ontario through our PowerPlay program. While many corporate giving initiatives were scaled back this year, we continued to invest in the communities we serve.

From the engineers planning the future of Ontario's grid, to the line maintainers who climb poles in icy darkness, and everyone in between, I'd like to thank all Hydro One staff for giving their best every day. I'd like to thank the members of the management team for their tremendous contributions and the Board of Directors for their continued guidance. I believe by ensuring that everything we do reflects health and safety, stewardship, excellence and innovation, we will continue to deliver the electricity system that the great province of Ontario deserves.

L Formusa

Laura Formusa
President and Chief Executive Officer
Hydro One Inc.

Prudently managed and profitably operated, Hydro One has a strong track record for delivering value as well as for transmitting and distributing electricity.



Focused on Productivity

At Hydro One, we are always looking for ways to improve productivity. In 2009, we introduced two new rigorous performance metrics: Cost per Asset Value for transmission and Cost per Line Length for distribution. These two metrics allow us to do a better job of benchmarking our performance against industry peers and to better monitor our productivity on a year over year basis. In our first year using these metrics, we met our targets for both.

Other process changes in 2009 that also led to improved productivity, included:

- *Using the SAP schedule tool* to better monitor maintenance task cycles, which enabled us to reduce equipment time outages and to dispatch work crews more efficiently.
- *Launching a Customer Care initiative* that reduced the volume of billing exceptions requiring manual interventions. This initiative also focused on improving handling and tracking processes in order to reduce handling time, eliminate errors and cut costs.
- *Adopting a Strategic Sourcing Model* that enhanced our work program delivery by giving us better, more secure access to critical long lead time materials.

Strong Financial Performance

Hydro One is focused on performance. As Ontario's largest electricity transmission and distribution company, our mission is to operate profitably, to create value for our shareholder and to be a safe, reliable and cost effective transmitter and distributor.

In 2009, we met our financial targets with a net income of $470 million and revenues of $4,744 million. We paid $188 million in dividends to our shareholder, the province of Ontario, and $77 million in payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation.

In a challenging financial market, Hydro One kept its "A" credit rating, ensuring that we can continue to borrow money over the long term on a cost effective basis. We also raised $1.15 billion in long term financing, enabling us to meet the cash requirements for debt retirements and capital programs in an economical and timely manner.

Our success shows that Hydro One remains an attractive investment. It also highlights the benefits delivered by the Company's efforts to establish strong relationships with credit rating agencies, banks and potential investors.

$470 MILLION — Net Income for Fiscal Year 2009

$1.15 BILLION — Raised in Long-Term Financing

$188 MILLION — Paid in Dividends to the Province of Ontario

#1 — On *Corporate Knights'* Best 50 Corporate Citizens List

Noteworthy Achievements

Hydro One is helping to build a conservation culture within Ontario. We are also working to establish a corporate culture that values transparency and accountability, that celebrates diversity, and that supports employees at work and in the community.

In 2009, our efforts were rewarded with significant recognition.

In their annual listing of the country's best 50 corporate citizens, *Corporate Knights* magazine named Hydro One as Canada's Top Corporate Citizen. The magazine's rankings are based on a wide ranging review of publicly reported environmental, social and governance indicators, including diversity, pension quality and health and board independence. In 2009, aboriginal relations were also weighed as an indicator.

"The ranked companies are doing the best job at fulfilling their end of the social contract and managing their specific environmental, social and governance performance when compared with their sector peers."

Corporate Knights magazine

Hydro One was also named one of the Top 90 Toronto Employers for 2010. After reviewing applications from more than 2,600 employers, Mediacorp Canada Inc. recognized Hydro One for supporting employees through ongoing skills training, and for its efforts to support employee involvement in the communities where they work.

In 2009, Hydro One met the challenge of providing reliable service while replacing end-of-life equipment within our system. We also helped to implement the Green Energy Act and did our part to secure Ontario's energy future.

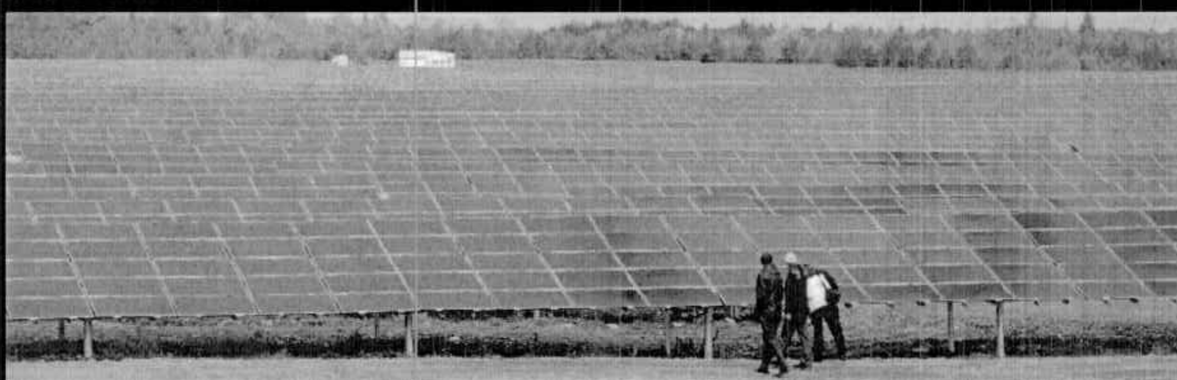


Photo courtesy of Skypower Limited.

Building Ontario's Green Future

Ontario's Green Energy Act lays out a framework to make the province a global leader in clean energy development through the use of renewable energy, distributed energy and conservation, and by creating thousands of jobs. Hydro One's role is to facilitate the connection of a wide variety of energy sources to the grid and ensure that our transmission and distribution system can deliver renewable energy from where it is generated to where it is needed.

Hydro One is currently reviewing core transmission network upgrades across Ontario necessary to support clean energy.

1 MILLION

SMART METERS INSTALLED IN 2009

Reaching a Smart Goal

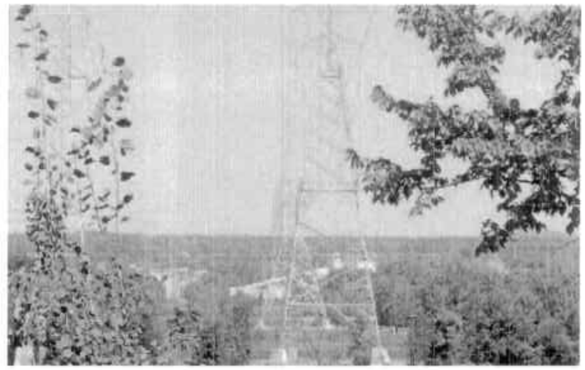
In one of the largest smart meter deployments undertaken by any utility in North America, Hydro One surpassed the key milestone of one million smart meters installed, with almost 750,000 meters communicating at a level capable of reliable meter reading. With this critical infrastructure in place our customers can begin converting to time of use pricing in 2010/2011.

16 10+ KW

RENEWABLE GENERATORS INTEGRATED INTO ONTARIO'S POWER GRID

Supporting Renewable Energy Generation

Hydro One is crucial to the successful implementation of the Green Energy Act. As more energy from renewable generation sources, such as solar, wind and biomass, becomes available, Hydro One will take the lead in integrating this energy into Ontario's electricity system, safely and cost effectively. In 2009, 16 renewable generators, each capable of producing more than 10 KW of electricity, were connected to our distribution system.



Ensuring Reliability. Increasing Capacity.

In 2009, Hydro One invested $918 million in transmission capital projects which included a number of network upgrades designed to facilitate access to new sources of renewable generation and to increase our transfer capability from other jurisdictions.

One of these initiatives, the Bruce to Milton Transmission Reinforcement Project, will connect refurbished nuclear and new wind generation sources in the Huron Grey Bruce area. Hydro One received the Environmental Assessment approval in December 2009, and construction will begin in 2010.

To provide reliable service to our customers, we continually monitor and evaluate our infrastructure. In 2009, the Southwestern Ontario Capacitor Banks Project identified four capacitor banks that based on age, condition and importance to the system were approaching their end of life. We made replacing this critical equipment a priority, and installed new capacitors which will also expand transmission capacity in southwestern Ontario.

The connection between our Cherrywood Transformer Station and our Claireville Transformer Station was reinforced to improve reliability and to ensure that it could meet growing demand within the Greater Toronto Area (GTA).

$918 MILLION

INVESTED IN TRANSMISSSION CAPITAL IMPROVEMENTS

Green energy. Educational partnerships. Community outreach. Just a few examples of our commitment to good corporate citizenship in action.

Committed to Conservation

Our commitment to continually improve our environmental performance includes helping Hydro One customers manage their electricity usage more efficiently. In 2005, we launched our Conservation and Demand Management program. Since then, more than 1.5 million customers have saved over 450 million kWh of electricity. That's enough to power approximately 38,000 homes for a year, resulting in greenhouse gas emissions savings of more than 300,000 tonnes of CO_2.

Hydro One employees are reducing their impact on the environment by cutting back on paper use, shutting down engines and turning off computers and unnecessary lights. Initiatives launched through our employee driven Greener Choices program have resulted in a reduction of an estimated 900 tonnes of CO_2 emissions.

Greener Fleet Rates Gold

Hydro One's efforts to improve both the fuel efficiency and environmental management of our fleet of service vehicles earned us the gold rating from Canada's Energy, Environment and Excellence group. The E3 Fleet program recognizes companies and governments that increase their fleet's fuel efficiency, reduce their carbon footprint and demonstrate leadership in fleet management excellence. Our gold rating was based on a reduction of 525 tonnes of CO_2 emissions achieved by minimizing idling, launching a smart tire inflation campaign, purchasing more fuel efficient vehicles and optimizing fuel performance by collecting and analyzing vehicle use data.

Improved Service and Convenience

In 2009, we relaunched our customer website, **www.HydroOne.com**. Now it is easier than ever for Hydro One customers to pay their bills online, manage their accounts and find tips on saving electricity. The site's new power outage tracking system uses state of the art mapping technology to provide customers and other system stakeholders with comprehensive, real time updates on the size and location of outages, the number of customers affected and the estimated time of service restoration.

161 New Graduates Hired by Hydro One Since 2008

New Skills. New Opportunities.

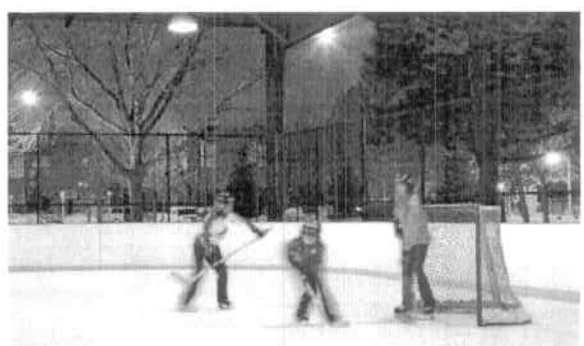
To be sure we have the people we need to fulfill our mandate of delivering safe, reliable and affordable electricity, Hydro One has taken the lead in establishing partnerships with colleges, universities and First Nations and Métis people. Since 2008, we have hired 161 young professionals into our new graduate program and brought on 393 apprentices.

In February 2009, Colleges Ontario recognized Hydro One with an award for our efforts in advancing college education in the province. Hydro One has invested more than $3 million to partner with Ontario colleges to train and recruit people as engineering technicians and technologists as well as other trades positions in the electricity sector.

Partners in Powerful Communities

Hydro One believes in helping to build strong, healthy communities. Our PowerPlay program provides grants of up to $25,000 to support capital projects for community centres, indoor or outdoor ice rinks, playgrounds, splash pads and sports fields places where members of the communities we serve can get together and children can engage in sports and active play. In 2009, Hydro One gave a total of $1 million for PowerPlay grants to 108 community projects.

108 PowerPlay Grants to 108 Community Projects in 2009



Visit www.HydroOne.com to read more about what Hydro One is doing for the environment and our customers in the Social Responsibility Highlights brochure.

Hydro One Senior Management

Laura Formusa
President and Chief Executive Officer, Hydro One Inc.

Joe Agostino
General Counsel

Myles D'Arcey
Senior Vice-President, Customer Operations

Steve Dorey
Vice-President, External Relations

John Fraser
Vice-President, Internal Audit and Chief Risk Officer

Tom Goldie
Senior Vice-President, Corporate Services

Peter Gregg
Senior Vice-President, Corporate and Regulatory Affairs

John Macnamara
Vice-President, Health, Safety and Environment

Carmine Marcello
Senior Vice-President, Asset Management

Nairn McQueen
Senior Vice-President, Engineering and Construction Services

Geoff Ogram
Senior Vice-President and Special Advisor

Wayne Smith
Senior Vice-President, Grid Operations

Sandy Struthers
Senior Vice-President and Chief Financial Officer

Ali Suleman
Vice-President and Treasurer

Corporate Information

Corporate Address
483 Bay Street
Toronto, Ontario M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

Investor Relations
(416) 345-6867
investor.relations@HydroOne.com

Media Inquiries
(416) 345-6868
1-877-506-7584

Customer Inquiries
Power outage and emergency number:
1-800-434-1235

Residential, farm and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
KPMG LLP

Concept and Design: THE WORKS www.worksdesign.com

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit www.HydroOne.com.

Mixed Sources

FSC

ANNUAL REPORT 2009

Investing in Ontario's Energy Future

hydroOne

Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom services.

Hydro One Networks Inc.
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 21 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our fibre-optic capacity to business customers. This business represents less than 1% of our total assets.

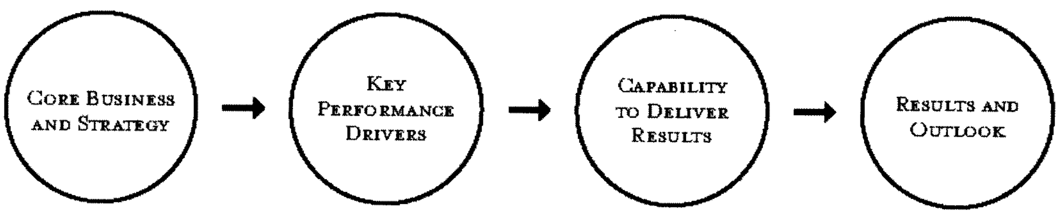
Management's Discussion and Analysis

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2009 and 2008.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (the Province), and our Transmission and Distribution Businesses are regulated by the Ontario Energy Board (OEB). Our mandate is to provide safe, reliable and cost-effective transmission and distribution of electricity to Ontario electricity users. We operate as a commercial enterprise with an independent Board of Directors. Our strategy is driven by our values: safety, stewardship, excellence and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial and transparent and values our customers. We strive for excellence by being trained, prepared and equipped to deliver high quality service. We value innovation because it allows us to increase our productivity and to develop enhanced methods to meet the needs of our customers. In 2009, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure while preparing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following governance structure:



Core Business and Strategy

Our corporate strategy is based on our mandate, vision and values. Our vision is to be the leading electricity delivery company in North America. Our strategic goals, which are discussed on page 3, encompass the core values that drive our business. Our strategy touches every part of our core business: safety, our customers, innovation, the reliability and efficiency of our systems, the environment, our workforce, shareholder value, and productivity.

Key Performance Drivers

We have identified performance drivers critical to achieving our strategic goals. Each driver is specific to measuring our success of a specific goal. We establish specific performance targets against each driver every year aimed at achieving our strategic goals over time. For example, we calculate lost-time injury frequency to measure our progress toward an injury-free workplace and use customer surveys to measure the success of our initiatives to increase customer satisfaction. Reduced carbon emissions and the results of our energy efficiency audit are indicative of our commitment to protecting the environment. These and other key performance drivers are included in our discussions of our performance measures beginning on page 4.

Capability to Deliver Results

We continued to use a balanced scorecard approach and set 13 stretch targets for 2009. We continue to strive to manage our key performance drivers and deliver results each and every year. This year we met or exceeded 8 of 13 targets. In delivering results, we remain conscious of our environmental footprint. We exceeded our target for greenhouse gas reductions by 125 metric tonnes, or approximately 31%, and exceeded our target for distribution customer interruptions by 0.4 hours, which is an improvement from last year of 1.2 hours, or nearly 15%. The results of our efforts are fully discussed in the section Performance Measures and Targets beginning on page 4. Our capability to deliver results in each of our strategic areas is limited by risks inherent in the regulatory environment, our business, our workforce and the economic environment. These risks, as well as our strategies to mitigate them, are discussed on page 22.

Results and Outlook

During 2009, our financial fundamentals remained strong, with current year net income of $470 million. Our OEB-approved revenue requirement for our Transmission Business for 2009 was $1,180 million. For our Distribution Business, rates were approved on the basis of the OEB's third generation incentive regulation mechanism (IRM). The approved rates support our work programs necessary to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable or cleaner generation. We maintained "A" category credit ratings and successfully issued $1,150 million in debt financing. A full discussion of our results of operations and financing activities can be found beginning on pages 11 and 15, respectively.

Our estimated future capital expenditures have increased from those disclosed in the 2008 Annual Report primarily as a result of additional investments in the electricity system required to accommodate the anticipated increase in renewable energy generation associated with the Feed-in-Tariff (FIT) Program and investments in advanced technologies to increase functionality and reliability of the electricity grid under the GEA. On September 21, 2009, the Minister of Energy and Infrastructure asked our company to proceed with the planning, development and implementation of specific transmission projects, to develop and implement smart grid infrastructure, and to proceed with upgrades to enable distributed system connected generation. We agreed with this request and we are proceeding with an implementation plan. Our future capital expenditures are more fully discussed beginning on page 17.

Overview

Transmission

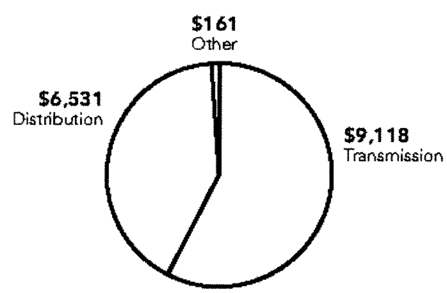
Substantially all of Ontario's electricity transmission system is owned and operated by our Company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centers. In 2009, we earned total transmission revenues of $1,147 million primarily by transmitting approximately 139 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,600 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 58% of our total assets.

Distribution

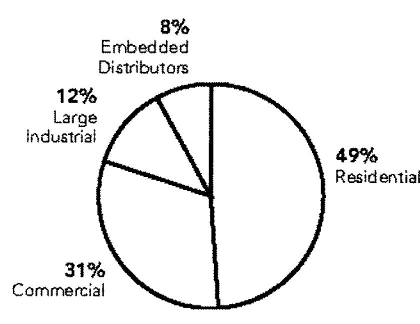
Our distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.3 million rural and urban customers, local distribution companies (LDCs) connected to the distribution system, and 44 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. We earned total distribution revenues in 2009 of $3,534 million. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers.

Total Assets

December 31, 2009 (Canadian dollars in millions)



2009 Distribution Revenues



Other

Our other business segment contributed revenues of $63 million in 2009 and has assets of about $161 million, which constitute 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. Hydro One Telecom recently constructed a dedicated optical network providing secure, high capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mandate, vision and values. Our mandate is to provide safe, reliable and cost-effective transmission of electricity to Ontario electricity users. Our vision is to be the leading electricity delivery company in North America. Our values include safety, stewardship, excellence and innovation. We are committed to providing innovation and leadership in renewing Ontario's power grid. To that end, we have identified eight strategic objectives:

Creating an injury-free workplace and maintaining public safety: We continue to focus on creating a passion for preventing workplace injuries and ensuring public safety.

Satisfying our customers: In order to satisfy our customers, we focus on reliability and power quality, communicating effectively with our customers, delivering on our commitments, partnering with the communities we serve, providing value for money and building our reputation as a trusted steward of provincial transmission and distribution assets.

Continuous innovation: We are committed to identifying and providing innovative solutions that improve the reliability and efficiency of electricity delivery and allow our customers more capability to manage their power costs.

Building and maintaining reliable, cost-effective power delivery systems: Our transmission strategy is to provide a robust and reliable provincial grid that can accommodate the Province's emerging generation profile and demand requirements. Our distribution strategy entails providing greater visibility, increased control and improved customer service through advanced grid technologies, while continuing to provide reliable service over a wide range of geography and climate.

Protecting and sustaining the environment: We play a central role in reducing Ontario's carbon footprint, both through the delivery of clean and renewable energy and through measures that allow our consumers to manage and reduce their energy usage. We are also focusing on our work methods and equipment, including fleet management and the transition of diesel generation in remote communities to biodiesel generation.

Skill development and knowledge retention: We are addressing our demographic challenges through a comprehensive program of recruitment, training in core competencies, staff development and knowledge transfer.

Maintenance of a commercial culture that increases value for our shareholder: We are committed to operating on a financially sustainable basis and to maintaining or increasing the value of our assets.

Productivity improvement and cost-effectiveness: To achieve our vision as the leading electricity delivery company in North America, we constantly strive to be the most productive through efficiency improvements and effective management of costs. Our goal is to be top quartile in key unit cost metrics relative to our North American electricity industry peer group.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of Ontario's economy and its residents.

Performance Measures and Targets

We measure and target our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we achieve our strategic objectives. In 2009, we met or exceeded 8 of 13 stretch targets. Overall, we are moving towards our strategic goals.

Creating an Injury-Free Workplace and Maintaining Public Safety

The potentially hazardous nature of our business requires a continuous focus on safety. Our people underpin everything we do, and as a result, safety is paramount. Our efforts to achieve an injury-free workplace are measured by our lost-time injury frequency. Overall, we met our challenging 2009 target of 0.3 lost-time injuries per 200,000 hours worked and achieved first quartile performance based on industry benchmarks. We monitor this measure to identify possible situations that may increase the risk of injury. These injuries range from strains to electrical contacts. We continuously emphasize the improvement of safety performance and strive to achieve zero lost-time injuries by ensuring that all staff are appropriately trained and equipped for the hazards that they may face. This involves continued coaching and mentoring, and building on our learning and experience. At the end of 2009, we launched Journey to Zero, a new program aimed at identifying key opportunities for improvement in our health and safety system. We continuously focus on maintaining public safety. In 2008, we began enhancing the security of our transmission stations in the Greater Toronto Area (GTA).

Satisfying Our Customers

Customer satisfaction is also vital to our success. This is measured through aggregate results of independent surveys conducted for each of our customer segments. Our Large Transmission Customer Satisfaction Survey results remained above target with an overall satisfaction level of 91%, reflecting our strong commitment to customer service. In addition, our Large Distribution Customer Satisfaction Survey results improved from 82% to 85% satisfied, as compared to 2008. We continue to be conscious of the needs of our residential and small business customers. Survey results showed an overall satisfaction level of 84%, which is slightly lower than target and last year's level; however, it surpassed the results of 2007 and 2006. We experienced lower results for generator customer satisfaction compared to 2008 for transmission connected and distribution connected generators. Addressing the concerns identified will be an area of focus for 2010. While our overall survey results for customer satisfaction fell short of our 2009 target, we continue to strive for customer service excellence. We continue to make our customers a high priority, and implement targeted strategies designed to meet the unique needs of each customer segment and address their concerns through a range of initiatives to improve customer satisfaction levels.

Continuous Innovation

We are committed to identifying and providing innovative solutions that will improve the reliability and efficiency of electricity delivery and allow our customers more capability to manage their power consumption. Among our continuous innovation initiatives, the installation of smart meters is a priority. We have installed 1,217,000 meters to date, of which 747,000 meters are communicating at a level capable of reliable meter reading. This is one of the largest smart meter deployments by a utility in North America. We fell short of our target of 800,000 meters enabled for meter reading due to the development of new technologies better suited for our rural environment, which will reduce the number of required repeaters and result in lower cost.

Building and Maintaining Reliable, Cost-Effective Power Delivery Systems

As stewards of the province's electricity grid, we aim to retain and build trust in our operations. In 2009, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for our customers in a safe, reliable and efficient fashion. In addition, our aim is to meet the growing demand for renewable generation. The reliability of our transmission and distribution systems is measured by the duration of unplanned customer interruptions throughout the year and our transmission system is further measured by the frequency of unplanned customer interruptions. In 2009, our distribution system performed better than planned, exceeding our target duration of 7.4 hours for customer interruptions with an actual duration of 7.0 hours. This performance is significantly improved from 8.2 hours in 2008.

Due to a number of challenges experienced throughout the year, the reliability of our transmission system was impacted in terms of both frequency and duration of interruptions. On August 20, 2009, tornados caused numerous momentary outages in Southern Ontario which were reflected in our 2009 transmission year-end frequency of unplanned customer interruptions; however, our results remained in the top quartile of performance based on the Canadian Electricity Association results for comparable systems in Canada. The event also affected our year-end transmission duration of unplanned customer interruptions which was 19.7 minutes; higher than the target of 12.4 minutes. This measure was further impacted by an interruption in January as a result of a low-probability high-impact failure at one of our transmission stations. Excluding these specific impacts, the duration measure came close to target. We are conscious that residential customers and businesses of all sizes require reliable service and consequently, we will continue to strive toward improving the reliability of both our transmission and distribution systems.

Protecting and Sustaining the Environment

As stewards of significant electricity assets, we have implemented a number of environmental initiatives aimed at instilling environmental awareness and action within our corporate culture. In 2009, we measured two key metrics related to oil spills and greenhouse gas reductions. We recovered approximately 97% of oil spills from oil-filled electrical equipment, exceeding our target of 90%. We have taken steps to ensure that our oil spill occurrences and response performance continue to improve. These include employee response training, the completion of environmental self-assessments, and the enhancement of our spill-containment systems at our transmission and distribution stations.

We take our responsibility to reduce our carbon footprint very seriously. In 2009, we removed approximately 525 metric tonnes of greenhouse gases from the environment, significantly exceeding our target of 400 metric tonnes. This achievement was due to a number of initiatives aimed at the efficiency of fleet utilization, including our Tire Smart Program and the purchase of fuel-efficient and hybrid vehicles. The environmental management of our fleet of service vehicles earned our company a gold rating from Canada's Energy, Environment and Excellence group. Our continued commitment to the people of Ontario has been recognized again this year by *Corporate Knights*, an independent company focused on promoting and reinforcing sustainable development in Canada. We were named the top Corporate Citizen in Canada, an improvement from our 6th place ranking in 2008. The ranking recognized us as having successfully managed our specific environmental, social and governance performance and having implemented a comprehensive Conservation and Demand Management (CDM) program.

Skill Development and Knowledge Retention

Given the retirement profile of our employees, we are entering a period of significant demographic change. This change is taking place across the electricity sector and we have taken a leadership role to address the transition. We have embarked on an aggressive workforce renewal program. In addition to our partnership with four community colleges, we strengthened our association with various Canadian universities as part of a comprehensive strategy to meet our staffing needs well into the future. Our goal to attract and retain future sector leaders involves demonstrating Hydro One as an employer of choice. In addition, we aim to facilitate retention and mentoring by focusing on employee engagement. We measure employee engagement across all lines of business using a confidential employee engagement survey. The grand mean score in 2009 was 3.63 out of 5, an improvement from the 2008 score of 3.51, but slightly lower than the 2009 target of 3.68. Detailed results of the 2009 survey will be used to actively address lower performing areas and effectively implement targeted strategies designed to increase engagement levels.

Maintenance of a Commercial Culture That Increases Value for Our Shareholder

In 2009, we continued our commitment to maintain strong financial fundamentals. Our targets included net income and our credit ratings, which were both achieved. A discussion of our financial results can be found on page 11 and our liquidity and capital resources on page 14. Our financial performance and the business environment in which we operate are taken into consideration in the setting of both our short-term and long-term credit ratings. During 2009, our long-term and short-term debt credit ratings remained unchanged. Credit ratings are provided by DBRS Limited, Moody's Investors Service Inc. and Standard & Poor's Rating Services Inc. (S&P). Maintaining credit ratings in the "A" category allows us to continue to access the long-term debt markets. We have been able to successfully secure sufficient and cost-effective debt financing even under extremely challenging market conditions. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

Productivity Improvement and Cost-Effectiveness

In 2009, we remained focused on workplace productivity and its contribution as an enabler of our work programs. For our Transmission Business, productivity is measured using the cost per asset value which is calculated as the capital and maintenance program expenditures as a percentage of transmission assets. For our Distribution Business, the calculation is normalized for line length due to the rural nature of our service territory. The targets for both measures were to achieve top-quartile when benchmarked against comparable North American utilities. Transmission productivity for the year was slightly better than target, and distribution productivity was essentially on target.

REGULATION

Our electricity Transmission and Distribution Businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the Ontario Power Authority (OPA). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period. Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB, and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among others. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP), which was submitted for OEB review and approval in August 2007. On September 17, 2008, the Province directed the OPA to review a portion of its proposed IPSP focusing on renewable energy and conservation as well as to undertake an enhanced process of consultation with First Nations and Métis communities. As a result of this directive and the enactment of the GEA, we are uncertain as to when the OPA will file a revised IPSP.

The GEA provides the framework for renewable energy projects and increased conservation. A number of regulations and programs, needed to fully implement the legislation, were introduced in the latter part of 2009.

An amendment to the deemed licence conditions of the *Ontario Energy Board Act, 1998*, as set out in the GEA, requires that distributors provide priority connection access for qualified renewable energy generation facilities and prepare plans for approval by the OEB that identify expansion or reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities.

The OPA continues to procure new, cleaner and renewable generation in Ontario. On September 24, 2009, the OPA announced the FIT Program in accordance with the directive issued by the Minister of Energy and Infrastructure to the OPA. The program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW. As a result of the September 21, 2009 letter from the Minister of Energy and Infrastructure, our company is working proactively with the appropriate organizations within our industry to develop strategies and processes to address generation requirements and assess the impact on our network.

In 2009, the OEB undertook a review of its codes, rules and guidelines in support of the GEA. On October 20, 2009, the OEB finalized amendments to the Transmission System Code (TSC), and adopted a "hybrid" approach to cost responsibility between transmitters and generators for "enabler facilities." Enabler facilities are lines or stations to connect two or more renewable generation facilities to the transmission grid. The hybrid option would see the initial pooling of the costs of enabler lines by the transmitter, with generators paying their pro-rata share, based on generator capacity, when ready to connect. To be eligible for this cost treatment, enabler facilities must meet certain detailed requirements established in the TSC.

The amendments to the Distribution System Code (DSC), finalized on October 21, 2009, revised the OEB's approach to assigning cost responsibility between a distributor and a generator for the connection of renewable energy generation facilities. The OEB defined three types of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. For generators that are connecting directly to a distributor's system, connection asset costs will continue to be borne by generators, while distributors will be required to fund all expansion costs identified in a plan, other generator-requested expansion costs up to a cap of $90,000/MW per project (the generator paying the rest), and all renewable enabling improvements.

In 2009, the OPA continued to be responsible for coordinating the delivery and funding of CDM programs. This coordination furthered initiatives undertaken by individual LDCs, including the Distribution Businesses of our subsidiaries Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton), as a result of OEB program requirements associated with the third phase Market Adjusted Rate of Return (MARR). Our CDM programs funded through the OPA in 2009 amounted to approximately $16 million compared to $8 million in 2008. In 2008, we completed our OEB program requirements associated with the third phase of MARR which amounted to approximately $43 million. The *Ontario Energy Board Act, 1998*, as amended by the GEA, provides direction to the OEB to take steps as specified to establish CDM targets to be met by LDCs and other licensees. The directive may require the OEB to specify, as a condition of a licence, the conservation targets to be met by LDCs and other licensees. To date, no such directive has been issued to the OEB and we have not been provided specific targets.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario by December 31, 2010. These meters are expected to be capable of measuring and reporting usage over predetermined periods, being read remotely, and, when combined with communications systems, will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the interim smart meter entity that will oversee the collection and management of data. LDCs, including our Distribution Businesses, are accountable for the deployment of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time-of-use rates that are presently voluntary. We are advancing solidly toward our goal of having smart meters installed in every home and business by December 31, 2010. In 2009, we were also able to complete the majority of interface testing, including rural application. In 2010, we will continue to focus on building an advanced distribution solution that will leverage our smart meter investment required to connect and manage large volumes of distributed generation on our distribution system (see Future Capital Expenditures).

TRANSMISSION RATES

Hydro One Networks

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, showed confidence in our work programs by approving all of our operating and capital expenditures for 2007 and 2008. However, the decision resulted in an estimated 8% annual reduction in transmission rates primarily due to a reduction in the approved return on equity (ROE) from 9.88% to 8.35%, based on a formula used by the OEB in the regulation of LDCs. Further, the OEB approved final amounts and disposition treatments for certain regulatory accounts including the Revenue Difference Deferral Account (RDDA), Earnings Sharing Mechanism (ESM), export and wheeling fees liabilities and the transmission market ready regulatory asset. The disposition of the RDDA and ESM was factored into rates and refunded to customers over the 14-month period from November 1, 2007 to December 31, 2008, while the export and wheeling fees liability and transmission market ready regulatory asset are factored into rates over the four-year period ending December 31, 2010.

As part of a joint proceeding involving all transmitters in Ontario on October 17, 2007, the OEB approved UTRs for implementation on November 1, 2007, through to December 31, 2008. The new rates reflected the approved changes to our revenue requirement and charge determinants and were, on average, 12% lower than previously approved rates primarily due to a reduction in the ROE. The new rates resulted in an approximate 1% decrease in the average customer's total electricity bill.

On May 30, 2008, we submitted an application to the OEB to adjust UTRs for our Transmission Business, effective January 1, 2009. On August 28, 2008, the OEB approved our application reflecting the 2008 OEB-approved revenue requirement given the full repayment to customers of the ESM and RDDA as at December 31, 2008. This resulted in an average increase of approximately 9% in our revenue requirement allocation from UTRs and an approximate 1% increase on an average customer's total bill.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirements of approximately $1,233 million and $1,341 million based on a ROE of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision, effective July 1, 2009, which resulted in a reduced revenue requirement of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to a lower approved ROE of 8.01% and 8.16%. The decision also required the establishment of new variance accounts to track the difference between the forecasted and actual external revenues for export services, secondary land use and net maintenance services primarily provided to generators. The OEB decision disallowed development capital expenditures of $180 million in 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, we filed supplemental evidence regarding two of the development capital projects amounting to approximately $160 million. On December 16, 2009, the OEB approved our supplemental submission increasing the approved 2010 revenue requirement to $1,257 million on the basis of an updated 2010 ROE of 8.39%. These decisions resulted in an increase in transmission tariff rates of approximately 2% and 9% for 2009 and 2010, respectively, representing a less than 1% increase on an average customer's total bill in each year.

On December 11, 2009, the OEB issued its final report on the cost of capital review which was initiated to determine whether current economic and financial market conditions warranted an adjustment to any of the cost of capital parameters values used by the OEB to set utility ROE. In its report, the OEB decided to continue to use a formula-based equity risk premium approach; however, the OEB determined that the current formula-based ROE needed to be reset and refined.

As a result of the OEB's cost of capital report, on January 5, 2010, we filed a motion with the OEB to review aspects of its decision on our 2010 transmission rates. Specifically, we requested that the ROE and short-term debt rate used in calculating the 2010 revenue requirement be increased to 9.75% and 1.93%, respectively, to reflect the application of the approved rates under the new OEB-approved formula. The oral hearing is scheduled for March 26, 2010.

We are currently preparing evidence to support a transmission rate application for 2011 and 2012. The application is anticipated to be filed with the OEB in the first quarter of 2010. This application will continue to support aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application will be filed using the new OEB-approved formula for ROE and is anticipated to take into consideration the OEB staff report on the regulatory treatment of infrastructure investment in connection with rate-regulated activities of Ontario distributors and transmitters, issued in January 2009. The report allows utilities to include prudently incurred construction work in progress in rate base, among other things.

DISTRIBUTION RATES

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO who facilitates payments to other parties such as generators, the Ontario Electricity Financial Corporation (OEFC) and the IESO itself.

In 2006, the OEB initiated a process to establish an IRM for the years 2007 to 2010. The process included a formulaic approach to establishing 2007 rates with a rate re-basing approach to be staggered across all Ontario distributors between 2008 and 2010.

Hydro One Networks

In accordance with the OEB's multi-year distribution rate-setting plan, our subsidiary Hydro One Networks, submitted the revenue requirement portion of its 2008 cost of service application on August 15, 2007. The application sought the approval of a revenue requirement of $1,067 million based on a ROE of 8.64%. We requested a distribution rate increase amounting to a net average increase of less than 1% on the average customer's total bill. The application included a plan to reduce the number of customer rate classes and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes.

On December 18, 2008, the OEB issued a decision approving substantially all of our work program expenditures, effective May 1, 2008, with an implementation date of February 1, 2009. The decision approved the establishment of the Revenue Recovery Account (RRA or Rider 4) to record the revenue differential between existing distribution rates and new rates from May 1, 2008. The RRA is being recovered over a 27-month period, commencing February 1, 2009, and ending April 30, 2011. As part of the decision, the OEB also approved certain excess functionality expenditures for smart meters and the continuance of the $0.93 cents per month per metered customer. In a past proceeding, the OEB approved our expenditures incurred related to minimum functionality for advanced metering infrastructure for recovery. As a result, the difference between revenue recorded on this basis and actual recoveries received under existing rate adders are reflected as the carrying value of the regulatory asset account.

In late 2008, we filed an incentive regulation application for 2009 rates, which was updated in January 2009, to reflect the impact of the 2008 distribution rate decision. The application was filed on the basis of the OEB's third generation IRM process which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision approving the basic IRM increase and a change of $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009, with an implementation date of June 1, 2009, and resulted in an increase of less than 1.5% on an average customer's total bill.

In 2009, we filed a cost of service application with the OEB for 2010 and 2011 distribution rates reflecting our plan to invest in our network assets to meet objectives regarding public and employee safety; regulatory and legislative compliance; maintenance of system security and reliability of system growth requirements; and investments required by the GEA. The application seeks OEB approval of revenue requirements of approximately $1,150 million and $1,264 million based on a ROE of 8.11% and 9.09% for 2010 and 2011, respectively. The resulting distribution tariff rate increase is approximately 10% and 13% in 2010 and 2011, respectively, or approximately 3% and 4% on an average customer's total bill. The oral hearing began on December 7, 2009.

As a result of the OEB's cost of capital report issued in December 2009, we subsequently updated our revenue requirement. The revised revenue requirements of $1,196 million in 2010 and $1,295 million in 2011 reflect the application of the ROE of 9.75% under the cost of capital formula.

Our application included the Green Energy Plan for our Distribution Business, filed in response to the GEA which directed the OEB to require transmitters and distributors to file plans that would lead to the expansion of their systems to facilitate renewable energy. Our plan identifies the expansion and reinforcement of the distribution system required to accommodate the connection of renewable energy generation facilities and plans for the development and implementation of the smart grid in relation to our distribution system.

We filed an update to our pre-filed evidence on September 25, 2009, to reflect changes to the *Ontario Energy Board Act, 1998*, as amended by the GEA and stipulated in Ontario Regulation 330/09. The amendments provided a new mechanism for rate protection whereby some or all of the OEB-approved costs incurred by a distributor to make an eligible investment for the purpose of connecting or enabling the connection of renewable energy generation to its distribution system may be recovered from all provincial ratepayers rather than solely from ratepayers of the distributor making the investment. In the last quarter of 2009, the OEB initiated a proceeding to address the extent to which the cost of distribution system investments made to enable the connection of renewable generation can be recovered from all of the province's ratepayers in accordance with Ontario Regulation 330/09. The OEB has expressed its preference to delay our oral hearing until the OEB issues its final report. We anticipate the oral hearing to resume in the first quarter of 2010.

Hydro One Brampton

On November 1, 2007, our subsidiary Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's second generation IRM policy that incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 19, 2008, the OEB released its decision and revised rates, including an amount of $0.67 cents per month per metered customer for smart meters, and were approved with an implementation date of May 1, 2008. The overall impact on an average customer's total bill was a reduction of approximately 3%.

On November 7, 2008, an application was filed on the same basis for 2009 distribution rates. On March 13, 2009, the OEB released its decision and approved the submission on the basis of its second generation IRM policy. The revised rates, including an amount of $1.00 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009. Overall, the impact on an average customer's total bill was marginal.

On November 6, 2009, an application for 2010 distribution rates was filed on the basis of the OEB's second generation IRM process, for which the overall impact on an average customer's total bill would be marginal. Their distribution rates will be put forth for a cost of service re-basing in 2011.

Hydro One Remote Communities Inc.

On August 29, 2008, we filed a 2009 cost of service rate application proposing an increase of about $10 million over the 2006 approved revenue requirement as a result of increased fuel costs. On April 30, 2009, the OEB issued a decision regarding this rate application approving all work program expenditures and the proposed rate increase of 4.4% effective May 1, 2009, resulting in a 4.4% increase to an average residential customer's total bill.

On November 4, 2009, we filed an application for 2010 rates under the OEB's third generation IRM, seeking approval of an increase of approximately 2% to basic rates for the distribution and generation of electricity effective May 1, 2010, which would increase an average customer's total bill by 2%. The increase reflects the standard inflationary adjustments incorporated in the third generation IRM applications.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	$ Change	% Change
Transmission	**1,147**	1,212	(65)	(5)
Distribution	**3,534**	3,334	200	6
Other	**63**	51	12	24
	4,744	4,597	147	3
Average annual Ontario 60-minute peak demand *(MW)*[1]	**20,798**	21,820	(1,022)	(5)
Distribution – units distributed to customers *(TWh)*[1]	**28.9**	29.9	(1.0)	(3)

[1] System-related statistics include preliminary figures for December.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenue associated with transmitting excess generation to surrounding markets and ancillary revenues, which are primarily attributable to maintenance services primarily provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were lower by $65 million, or 5%, compared to 2008, mainly due to lower average monthly peak demands experienced during the year. The average annual Ontario 60-minute peak demand and the overall related load were 1,022 MW and 12,262 MW lower than last year, respectively, resulting in lower revenues of $36 million.

Export service revenue attributable to the transmission of electricity to other jurisdictions was lower by $14 million as a result of lower volume and the impact of the May 28, 2009 OEB decision. This decision also resulted in lower ancillary revenues of $9 million. The OEB decision requires export services and net ancillary revenues in excess of forecast levels to be recorded as regulatory liabilities for disposition to ratepayers.

Transmission revenues for the year were also affected by two other OEB-approved transmission tariff rate increases that occurred during the year. These increases were offset by adjustments to our earned revenues reflecting the refund of the amounts previously recorded as revenue reductions in prior years which resulted in a net decrease of $6 million during the year.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $200 million, or 6%, compared to 2008 including an increase in the recovery of higher purchased power costs of $145 million, as described below under Purchased Power.

After deliberation of our written and oral evidence, the OEB approved increases related to our smart meter program and our distribution tariff for our subsidiary Hydro One Networks. The decisions were issued on December 18, 2008, in respect of our cost of service application, and on May 13, 2009, in respect of our rate application under the IRM. As a result, our distribution revenues increased by $64 million compared to last year. These tariff rate increases, which support the maintenance and investment requirements of our distribution system that enable the safe and reliable delivery of electricity to our customers throughout Ontario, were implemented on February 1, 2009, and June 1, 2009, respectively.

Distribution revenue increases were partially offset by lower energy consumption, resulting primarily from the milder weather and the economic downturn, which reduced our distribution revenues by $11 million compared to last year. In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective March 31, 2008, resulting in a reduction of $5 million for the year.

We also experienced higher other revenues of $7 million primarily due to the recognition of certain OEB-approved deferral accounts and increased OPA incentive revenues from the implementation of OPA-funded CDM programs during the year.

Other

Higher revenues derived from a newly constructed dedicated optical network, which provides secure, high capacity connectivity across numerous health care locations in Ontario, contributed to an increase in revenues in our Telecom Business of $12 million, or 24%, compared to 2008.

Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the IESO wholesale market service charges and transmission charges levied by the IESO. The commodity cost of energy for low-volume and other designated customers are based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts adjusted twice annually. Customers that are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP impacting the reporting period is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	Residential	Non-Residential	First Tier	Second Tier
November 1, 2007	1,000	750	5.0	5.9
May 1, 2008	600	750	5.0	5.9
November 1, 2008	1,000	750	5.6	6.5
May 1, 2009	600	750	5.7	6.6
November 1, 2009	1,000	750	5.8	6.7

Purchased power costs increased in 2009 by $145 million, or 7%, to $2,326 million for the year compared to 2008. The increase in our purchased power costs was primarily due to the impact of changes in the OEB's RPP rate for residential and other eligible customers of $122 million, the impact of higher charges levied by the IESO of $33 million which includes increased wholesale market service charges, and an increase in purchased power costs for customers who are not eligible for the RPP of $31 million. These increases were partially offset by a reduction of $41 million as a result of lower demand for electricity.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	$ Change	% Change
Transmission	**438**	387	51	13
Distribution	**564**	531	33	6
Other	**55**	47	8	17
	1,057	965	92	10

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $51 million, or 13%, in 2009 compared to last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were higher by $28 million compared to the prior year. These increases were primarily attributable to expenditures on our planned station maintenance programs to address aging infrastructure, particularly on transformers and other power equipment and higher requirements for unplanned corrective maintenance. Our work program also included expanded forestry programs to improve system reliability and increased engineering support. Our expenditures in support of the transmission system have also increased by $23 million primarily reflecting the impact of lower expenditures in the prior year related to a one-time settlement credit associated with the transfer of assets to the Inergi LP (Inergi) pension plan following approval from the Financial Services Commission of Ontario (FSCO). Increased expenditures in support of the transmission system are also due to higher information technology application support and enhancements substantially offset by the reallocation of resources in support of our larger capital work program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $33 million, or 6%, compared to last year. Our work program expenditures increased by $18 million primarily resulting from higher expenditures on our customer care programs, expanded forestry programs to improve system reliability, unplanned line maintenance and corrective planned station maintenance. Our expenditures in support of our Distribution Business were higher by $15 million primarily reflecting the impact of lower expenditures in the prior year related to the one-time settlement credit associated with the transfer of assets to the Inergi pension plan. Increased expenditures in support of the distribution system are also due to higher information technology application support and enhancements partially offset by the reallocation of resources in support of our larger capital work program.

Depreciation and Amortization

Depreciation and amortization expense decreased by $11 million, or 2%, to $537 million this year. This decrease was attributable to reduced amortization primarily related to the full recovery of a regulatory asset in the prior year. The lower amortization was partially offset by increased depreciation expense mainly attributable to new assets coming in service, consistent with our ongoing capital work program.

Financing Charges

Financing charges increased by $16 million, or 5%, to $308 million for 2009 compared to last year. The increase was primarily due to higher net interest expense reflecting higher average levels of debt, lower investment income reflecting lower average investments and lower average short-term interest rates and a $6 million interest credit in the prior year related to the Inergi pension asset transfer settlement. The increase was partially offset by lower average long-term borrowing rates and higher interest capitalization due to increased construction associated with our ongoing capital work program.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the OEFC in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes, the liability method is used. The change in future taxes relating to the unregulated businesses and to the regulated businesses, in respect of temporary differences that are not considered for the rate-making process, result in a future tax provision that is charged to the income statement. The change in future taxes relating to temporary differences of the regulated business that are considered for the rate-making process results in a regulatory asset.

The provision for payments in lieu of corporate income taxes decreased by $67 million, or 59%, to $46 million compared to 2008. The year-over-year decrease results from a reduction in the statutory rate from 33.5% to 33.0% combined with the impact of increased temporary differences primarily relating to higher capital cost allowance being claimed on our information system and smart meter investments in excess of depreciation. These impacts were partially offset by an increase to the provision for future taxes.

Net Income

Net income of $470 million was lower by $28 million, or 6%, compared to 2008 results. Net income was affected by higher operation, maintenance and administration expenditures primarily related to planned work programs necessary to sustain our transmission and distribution systems and the impact of a one-time settlement credit in the prior year associated with the transfer of assets to the Inergi pension plan. Lower transmission revenues resulted from lower average monthly peak demands and lower export service revenues. These impacts were partially offset by a higher OEB-approved distribution tariff in support of necessary work programs that enable the safe and reliable delivery of electricity. In addition, payments in lieu of corporate income taxes were lower, reflecting higher capital cost allowance deductions.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2008 through December 31, 2009. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)			2009					2008
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31[2]	Sep. 30	Jun. 30	Mar. 31
Total revenues[1]	**1,207**	**1,144**	**1,090**	**1,303**	1,194	1,126	1,055	1,222
Net income[1]	**111**	**100**	**82**	**177**	131	112	98	157
Net income to common shareholder[1]	**106**	**96**	**77**	**173**	126	108	93	153

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008.

Liquidity and Capital Resources

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Operating activities	**892**	1,052
Financing activities		
Long-term debt issued	**1,150**	1,050
Long-term debt retired	**(400)**	(540)
Short-term notes payable	**55**	–
Dividends paid	**(188)**	(259)
Investing activities		
Capital expenditures	**(1,566)**	(1,284)
Other financing and investing activities	**15**	9
Net change in cash and cash equivalents	**(42)**	28

Operating Activities

Net cash from operating activities decreased by $160 million compared to last year, to $892 million. This reduction primarily resulted from higher accounts receivable balances reflecting increased commodity costs and collection cycles associated with the economy, combined with changes in accounts payable related to power purchases. There is a lag in timing between IESO invoices for power purchases and the collection of outstanding accounts receivable balances. In addition, our cash from operating activities was impacted by the net change in our transmission and distribution regulatory accounts, which included the 2008 repayment to our customers of amounts recorded in the transmission RDDA.

Financing Activities

Short-term liquidity is provided through funds from operations and our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days. At December 31, 2009, we had $55 million of short-term notes outstanding. The Commercial Paper Program is supported by committed revolving credit facilities with a syndicate of banks of $1,000 million as at December 31, 2009 maturing August 20, 2010. On February 2, 2010, the Company entered into an additional $500 million credit facility maturing in February 2013. On February 3, 2010, the Company reduced the $1,000 million credit facility maturing on August 20, 2010, to $750 million. In addition, in January 2010, the Company purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014, as a form of alternate liquidity to supplement its bank credit facilities. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2009, we had $6,875 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2010 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. On July 27, 2009, we filed a base shelf prospectus to renew our MTN Program for another 25 months. The maximum authorized principal amount of medium-term notes issuable under this program until August 2011 is $3,000 million, of which $2,750 million was remaining and available as at December 31, 2009.

		Rating
Rating Agency	Short-Term Debt	Long-Term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
S&P	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

We issued $1,150 million in long-term debt under our MTN Program in 2009 including $250 million issued under adverse economic conditions in the fourth quarter. We also repaid $400 million in maturing long-term debt. In comparison, during 2008, we issued $1,050 million in long-term debt under our MTN Program and we repaid $540 million in maturing long-term debt. In 2009, the amount of short-term notes increased by $55 million compared to last year but was unchanged in 2008. We also issued $500 million during the first month of 2010, leaving $2,250 million remaining issuable under the MTN Program as at February 11, 2010.

In 2009, we paid dividends to the Province in the amount of $188 million, consisting of $170 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $241 million and preferred dividends of $18 million. In 2009, cash dividends per common share were $1,700 compared to $2,410 per common share in 2008. Cash dividends per preferred share were $1.375 in each of 2009 and 2008.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations and maintenance of the deemed regulatory capital structure. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	$ Change	% Change
Transmission	**918**	704	214	30
Distribution	**643**	570	73	13
Other	**5**	10	(5)	(50)
	1,566	1,284	282	22

Transmission

Transmission capital expenditures increased by $214 million in 2009 to $918 million, compared to 2008. Expenditures to expand and reinforce our transmission system were $520 million, representing an increase of $218 million over last year. This increase is attributable to a number of significant inter-area network upgrade projects to support the supply mix objectives for generation as well as local area supply projects to address growing loads. We also experienced an increase in expenditures on our load projects, which was offset by a reduction in expenditures on our generation projects compared to the prior year. During 2009, we connected approximately 1,285 MW of new generation to our transmission system, compared to 1,940 MW in 2008.

Inter-area network upgrades with significant expenditures include the Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area; the South Western Ontario Capacitor Banks Project, which provides interim protection to the Bruce Nuclear facility and which will expand transmission capacity in South Western Ontario; the Cherrywood Transformer Station to Claireville Transformer Station Connection Project, which will enable greater transfer capability across the GTA to accommodate power flows resulting from the new Hydro Québec interconnection; and the Northeast Transmission Reinforcement Project, which will increase the North-South Interface transfer capability to access available northern generation. The impact of these investments was partially offset by the substantial completion in 2008 of an interconnection project with Québec that will increase access to emission-free hydroelectric power by 1,250 MW.

Local area supply projects with significant expenditures include our GTA West Transmission Reinforcement Project and our Woodstock Area Transmission Reinforcement Project, both of which will increase capacity to ensure supply reliability in those areas, and our Hurontario Transformer Station to Jim Yarrow Municipal Transformer Station connection, which will increase transmission capacity in the western Brampton area to allow for future load growth. The impact of these increases was partially offset by our Essa Transformer Station to Stayner Transformer Station connection, which was placed in service this year and has improved the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $281 million, representing an increase of $13 million compared to 2008. This increase was primarily due to the refurbishment and replacement of end-of-life equipment associated with various line and station projects and higher component replacement expenditures as a result of both emergency restoration work and planned work programs associated with aging infrastructure. These increases were substantially offset by lower expenditures relating to the completion of our Claireville Transformer Station Project which has improved reliability.

Our other transmission capital expenditures were $117 million in 2009, representing a reduction of $17 million from the prior year. This decrease was mainly attributable to lower project support requirements, lower expenditures associated with theft prevention programs and lower information technology project expenditures related to an entity-wide information system replacement and improvement project to replace end-of-life systems and improve productivity, the second phase of which was placed in service during the year.

Distribution

Distribution capital expenditures increased by $73 million to $643 million in 2009, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $332 million, an increase of $63 million compared to last year. These increases primarily reflect ongoing investments required to meet smart meter targets, consistent with government policy. During the year, we installed approximately 433,000 smart meters, bringing our cumulative program total to about 1,217,000 meters. We are also focused on the development and integration of the systems required for time-of-use billing, including meter reading capability and integration to the IESO meter data repository. This is one of the largest smart meter deployments by a utility in North America and will start to see our customers convert to time-of-use pricing in 2010.

Expenditures to sustain our distribution system were $242 million, an increase of $11 million from 2008. This increase was primarily the result of increased planned line work programs including the replacement of end-of-life equipment, increased investment to replace components within our distribution stations and increased engineering and construction work to upgrade or replace wholesale meters. These increases were partially offset by lower unplanned line work resulting from storm damage. Our other distribution capital expenditures were $69 million in 2009, which were relatively unchanged compared to the prior year. We experienced lower information technology project expenditures related to an entity-wide information system to replace end-of-life systems and improve productivity, the second phase of which was placed in service during the year. These were offset by increased other support costs including facilities improvement work.

Other

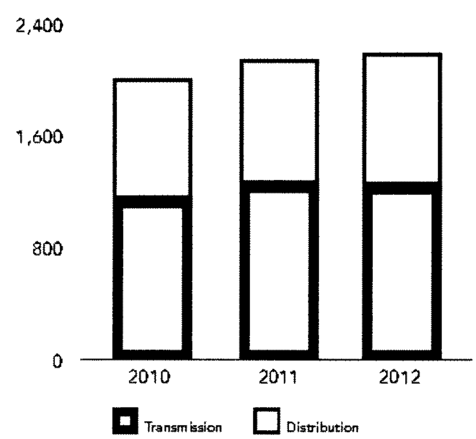
Other capital expenditures declined largely as a result of the substantial completion in 2008 of a dedicated network necessary to deliver on contracts providing secure, high capacity connectivity across numerous health care locations in Ontario.

Future Capital Expenditures

Our capital expenditures in 2010 are budgeted at approximately $2.0 billion. The 2010 capital budgets for our Transmission and Distribution Businesses are about $1,150 million and $850 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to increase to approximately $2.1 billion in 2011 and approximately $2.2 billion in 2012. These expenditures reflect the sustainment requirements of our aging infrastructure budgeted at approximately $530 million in 2010, $620 million in 2011 and $670 million in 2012. Development projects, including inter-area network upgrades that reflect supply mix policies to phase out coal generation and local area supply requirements, are budgeted at approximately $890 million in 2010, $780 million in 2011 and $550 million in 2012. These development investments also reflect the continued mass deployment of smart meters within our Distribution Businesses and the building of the required smart meter infrastructure in support of conservation objectives. We will leverage the smart meter investment to build a smart grid which will enhance our operations and support distributed generation. Other capital expenditures related to operations amount to approximately $410 million in 2010, $290 million in 2011 and $230 million in 2012. Our capital

Future Capital Expenditures

(Canadian dollars in millions)



expenditures to support the requirements under the GEA are approximately $190 million in 2010, $450 million in 2011 and $740 million in 2012. We are proceeding with our investments in support of the GEA to facilitate renewable generation consistent with the FIT Program.

Capital expenditures of our other business segment are budgeted at about $15 million in 2010, primarily reflecting the continued build out of the fibre-optic network.

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2010 to 2012, amounting to about $3.7 billion, including program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure to ensure a continued reliable supply of energy to customers throughout the province. The investment plan includes targeted component replacements of air blast circuit breakers, switchgear, autotransformers and wood pole structures to maintain the performance of assets. Also, the reconstruction of transformer stations is planned for the Burlington TS 115 kV Switchyard and Sir Adam Beck Switching Station to ensure future reliability. These sustaining investments are necessary to ensure that we will continue to meet all regulatory, compliance, safety and environment objectives.

Inter-area network projects, required to accommodate new generation related to supply mix policies, include our Bruce to Milton Transmission Reinforcement Project to connect nuclear generation and new wind generation in the Huron-Grey-Bruce area. In December 2009, we received conditional environmental assessment approval for the project, which involves constructing a new 500 kV line. In October 2009, Niagara Escarpment Commission (NEC) approval was obtained but this approval is presently under appeal. The appeal hearing is scheduled to be completed in February 2010. We are also installing station equipment in Southwestern and Northeastern Ontario to increase transmission capacity. Another project to increase transmission capability includes the installation of Static Var Compensators (SVCs) at existing stations in North Eastern Ontario. This equipment will mitigate congestion and enhance the transfer capability between Northern Ontario and Southern Ontario and the transmission system north of Sudbury, enabling new hydroelectric generation.

Other projects included in the transmission investment plan include local area supply transmission reinforcements, such as Southern Georgian Bay, Woodstock and Midtown Toronto, for which we recently filed a leave-to-construct application with the OEB.

We continue to work with our load customers in order to meet their growth requirements. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint-planning studies and throughout the consultation and approval processes, continue to be essential. Examples of projects under construction to meet the growing needs of our customers include a new transformer station to serve Mississauga and expansions of transformer stations serving Brampton, Kingston, York Region and Mississauga. To address other future needs for local load connections, we are in discussions with customers for major transmission expansions or new transformer stations and, where necessary, line connections in locations such as Mississauga, Oshawa, Woodstock, Essex County Chatham-Kent, Ancaster and Brampton. Targeted investments in customer delivery point performance, power quality and our 115 kV and 230 kV systems are expected to lead to improved reliability.

Our investment plan is also composed of capital expenditures to support the GEA. On September 21, 2009, the Province requested that we proceed with the planning and implementation of 20 major transmission projects across Ontario in support of the GEA and in anticipation of the increase in renewable energy generation associated with the OPA's FIT Program. These investments include bulk transmission investments, enabling lines and various equipment to support the two-directional flow of electricity. Our company is working proactively with the appropriate organizations within our industry to implement these requirements.

The development of distributed generation to be connected to the distribution system will require upgrades at some transformer stations, including the installation of SVCs. Where there is significant distributed generation interest, new dedicated transformer stations may also be required. Also, several major transmission development projects are required, with in-service dates between 2013 and 2020, to provide for new renewable generation. The construction of these projects is scheduled to commence after 2011. In the last quarter of 2009, we initiated the planning for the Northwest Transmission Expansion Project, as well as several other large projects, under Ontario's *Environmental Assessment Act*. The project is needed to incorporate new renewable generation, such as hydroelectric and wind, in the Lake Nipigon area and to provide additional electricity supply capability to meet the needs of existing and future customers in the area north of Lake Nipigon.

The actual timing and expenditures of many development projects are uncertain as they are dependent upon various approvals including OEB leave-to-construct approvals and environmental assessment approvals; negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities, as well as the timing and level of generator contributions for enabling facilities under recent amendments to the TSC. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Capital expenditures for the period 2010 to 2012 are estimated to be approximately $2.7 billion, including capital expenditures to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There is a continuation of investments to replace end-of-life equipment and components with a focused increase on wood pole replacements and submarine cables to address deteriorating assets. In addition, we will continue to address the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

In accordance with government policy, we anticipate having our Smart Meter Project substantially completed in 2010, with some work effort continuing into subsequent years. The deployment of smart meters will further be leveraged to create a smart grid that is capable of providing a communication infrastructure to enable new smart functions and applications across our system that will support the connection of clean and renewable generation. The budget includes investments in smart grid, commencing with standards and technology development for our time-of-use pilot.

Capital expenditures to support the requirements under the GEA include the undertaking of increased generation connection activity and performing upgrades to the distribution system, such as station upgrades for protection and control and the installation of circuit breakers or new feeder positions to accommodate new generation.

The actual timing and expenditures is uncertain as it is dependent upon various approvals, including OEB rate application approvals, as well as the extent to which the cost of distribution system investments made to enable the connection of renewable generation can be recovered from all of the province's ratepayers. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations as well as other major commercial commitments:

December 31, 2009 (Canadian dollars in millions)	Total	2010	2011/2012	2013/2014	After 2014
Contractual obligations *(due by year)*:					
Short-term note payable	55	55	–	–	–
Long-term debt – principal repayments	6,875	600	1,100	850	4,325
Long-term debt – interest payments	5,967	372	669	548	4,378
Inergi outsourcing agreement[1]	222	104	118	–	–
Operating lease commitments	59	9	12	12	26
Environmental obligations[2]	389	24	68	79	218
Total contractual obligations[6]	13,567	1,164	1,967	1,489	8,947
Other commercial commitments *(by year of expiry)*:					
Bank line[3]	1,000	1,000	–	–	–
Letters of credit[4]	112	112	–	–	–
Guarantees[4]	326	326	–	–	–
Pension[5]	10	10	–	–	–
Total other commercial commitments	1,448	1,448	–	–	–

[1] On March 1, 2002, Inergi began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term.

[2] The Company records a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands. The expenditure pattern reflects our planned work program for the period.

[3] As a backstop to our Commercial Paper Program, we have a $1,000 million revolving standby credit facility with a syndicate of banks which matures in August 2010. On February 2, 2010, the Company entered into an additional $500 million facility with a syndicate of banks which matures in February 2013. On February 3, 2010, the Company reduced the $1,000 million facility to $750 million.

[4] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements. The other $5 million included in letters of credit pertains to operating letters of credit relating to an agreement to purchase goods and to surety bonds. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million and on behalf of two distributors using guarantees of up to a maximum of $660 thousand. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category.

[5] Contributions to the pension fund are made one month in arrears. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

[6] In addition, the Company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these agreements are considered individually material, and the majority do not extend beyond December 31, 2010.

The amounts in the above table under Long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

Related Party Transactions

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the OEFC. In January 2010, the Company purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014, as a form of alternate liquidity to supplement its bank credit facilities.

Considerations of Current Economic Conditions

Effect of Load on Revenue

The load is expected to decline in 2010 due to the impact of CDM coupled with a below-average growth in the Ontario economy. The economic growth, although moderate, is expected to partially induce load growth in all sectors of the Ontario economy. Overall load growth due to economy alone is forecasted to be approximately 0.4%, with the commercial sector only marginally outperforming residential and industrial sectors. The load impact of CDM and Embedded Generation is expected to have a substantial negative impact on load growth of approximately 4%. On the whole, load is expected to decline by about 3.7%. A reduction in load will negatively affect our revenues.

Effect of Interest Rates

Changes in interest rates will impact the calculation of our revenue requirements filed with the OEB. The first component impacted by interest rates is the return on equity. The OEB-approved adjustment formula for calculating return on equity will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A" rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield or the "A" rated Canadian utility spread used in the current OEB formula for determining our rate of return on equity would reduce our Transmission Business' results of operations by approximately $15 million and our Distribution Business' results of operations by approximately $10 million. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

In support of our ongoing work program requirements, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, blanket orders, vendor alliances and manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts to our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counter-parties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a syndicated bank line of credit of $1,000 million as at December 31, 2009, and an additional credit facility of $500 million that was entered into on February 2, 2010. On February 3, 2010, the $1,000 million credit facility was reduced to $750 million. We have continued to issue sufficient cost-effective debt financing through the MTN Program and Commercial Paper Program in the Canadian debt markets to date despite the adverse economic conditions present at the beginning of 2009 and have sufficient available liquidity.

Pension

During 2009, the deferred pension asset reported on our balance sheet decreased by $17 million to $424 million. We contributed $112 million into our pension plan in 2009 and incurred $129 million in net periodic pension benefit cost. On an accounting basis, the 2008 unfunded benefit obligation of $171 million increased by $233 million to $404 million. The plan experienced positive returns of about 17.2% in the year. However, the plan was also impacted by an increase in the accrued benefit obligation primarily as a result of a decrease in the discount rate used for accounting purposes (see Critical Accounting Estimates – Employee Future Benefits).

Risk Management and Risk Factors

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our Company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising of direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our Company. Our Chief Risk Officer is responsible for the ongoing monitoring and reviewing of our risk profile and practices, and our Senior Vice-President and Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, are required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Senior Vice-President and Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008 the Province made a declaration removing certain powers from our company's directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi. In 2009, the Province required Hydro One, amongst other agencies, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Hydro One's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province's ownership of Ontario Power Generation Inc. (OPG), and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which could have a material adverse effect on our business.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our Transmission and Distribution Businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively affected by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2010. These expectations are factored into our revenue requirements for OEB approval, to ensure that the targeted CDM accomplishments do not result in deteriorated revenues. There is a risk that our revenues would be reduced if these targets are exceeded. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of any such compensation mechanism is yet to be determined. We are also subject to risk of revenue loss from other factors.

In response to the GEA, we expect to make a significant investment in the coming years in large-scale transmission and distribution infrastructure projects, and to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The distribution systems have generally been built to accommodate one directional flow of electricity from the transmission system to customers' meters. Distributed generation connected to the distribution system requires the accommodation of two directional flows. The risk exists that the OEB may not allow full recovery of such investments. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures. In addition, it is possible that we may not obtain all necessary regulatory approvals for these projects or if approvals are obtained, they may be subsequently challenged, appealed or overturned. This could impact our ability to recover costs already incurred in the planning and development of such projects.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2010 and 2013, including $600 million maturing in 2010 and $500 million maturing in 2011. We plan to incur capital expenditures of approximately $2.0 billion in 2010 and capital expenditures are expected to increase to approximately $2.1 billion in 2011. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

Risk Associated with Transmission Projects

The amount of power which may flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our networks to reliably transmit power from new and existing generation sources (including, expanded interconnections with neighbouring utilities) to load centres or meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

In many cases, these investments are contingent upon one or more of the following approvals and/or processes: (a) environmental approval(s) and (b) receipt of OEB approvals which can include expropriation and (c) appropriate consultation processes, and where appropriate, accommodation with First Nations and Métis who may be potentially affected by a project. Obtaining these approvals and carrying out these processes may also be impacted by public opposition to the proposed site of transmission investments, thus there is a risk that necessary approvals may not be obtained in a timely fashion or at all. This will adversely affect transmission reliability and/or our service quality, both of which could have a materially adverse effect on our company.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital and maintenance programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, including that opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities. Lead times for material and equipment have also increased substantially due to increased demand and limited vendor capability.

Adjustments to accommodate these external dependencies have been made in our planning. However, if we are unable to carry out these plans, in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Work Force Demographic Risk

By the end of 2009, more than 17% of our employees were eligible for retirement and by 2011 there may be more than 25% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We have already lost a considerable number of management staff, both those in executive positions and those who are logical successors for executive positions, to opportunities in other electricity sector positions across Canada (and, in particular, in Ontario) as well as senior positions outside of the sector. Moreover, we must also continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our business.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. We cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances, could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation (LAR) program covering most of our stations and service centres. It involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's polychlorinated biphenyl (PCB) regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025 while our LAR expenditures are expected to be incurred over the period ending 2020. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our Balance Sheet. We do not have insurance coverage for these environmental expenditures.

As a result of regulatory changes, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We plan on undertaking additional studies, using the assistance of external experts as required, to estimate the incremental expenditures associated with removing such materials prior to facility demolition. This information will allow us to reasonably estimate and record any obligation we may have to incur such expenditures. We also anticipate that such future expenditures will be recoverable in future electricity rates.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities, or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possess inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss, we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We continue to transition most of our financial and business processes to an integrated business and financial reporting system. The conversion of these systems and processes may expose us to risk, including risks associated with our ability to capture data and to produce timely and accurate information for downstream processing and to maintain internal controls. System failures or security breaches could have a material adverse effect on our company.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the FSCO on a triennial basis. The most recently filed valuation was prepared as at December 31, 2006, and was filed in September 2007. The next valuation is required to be prepared as at December 31, 2009, and will be filed in September 2010. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on investment returns, changes in benefits or actuarial assumptions. Economic uncertainty and financial market volatility contributed to negative returns in 2008 of approximately 22.5%. In 2009, the pension plan has experienced positive overall investment returns of approximately 17.2%. The deficit position at the end of 2009 is not expected to result in any significant change in our contribution requirements beyond 2009. A determination by the OEB that some of our pension expenditures are not recoverable from customers would have a material adverse effect on our company.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach, which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Businesses' net income by approximately $15 million and our Distribution Businesses' net income by approximately $10 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counter-parties. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*. The failure to properly manage these risks could have a material adverse effect on our company.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Energy Professionals. Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost efficient manner. Although we believe that we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2011, and the existing Society of Energy Professionals collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face some degree of operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999, did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the $822 thousand that we paid to these Indian bands and bodies in 2009. If we cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi. If the agreement with Inergi is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the functions involved, which could have a material adverse effect on our business, operating results, financial condition or prospects. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

Changes in Accounting Policies

Corporate Income Taxes

Effective January 1, 2009, we adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes* and CICA Handbook Section 1100, *Generally Accepted Accounting Principles.* These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, we recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Adjustments to retained earnings were recorded for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008, that are excluded from the rate-setting process.

Intangible Assets

Effective January 1, 2009, we adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which replaced CICA Handbook Section 3062, *Goodwill and Other Intangible Assets*, and CICA Handbook Section 3450, *Research and Development Costs.* The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and other intangible assets.

As a result of adopting this new accounting standard, we reclassified computer applications software previously classified as fixed assets and reclassified other assets previously classified as long-term other assets to intangible assets.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2009, amounted to $1,105 million and principally relate to future income tax, environmental costs and the rural rate protection variance account. We have also recorded regulatory liabilities amounting to $604 million as at December 31, 2009. These amounts pertain primarily to deferred pension, the regulatory liability refund account, future income tax, retail settlement variance accounts, and a regulatory asset recovery account (RARA I), which is currently in a liability position. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with PCB-laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of 2% has been used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded. Consistent with the requirements of Environment Canada's PCB regulations issued on September 17, 2008, estimated future PCB expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate for the period when an increase in obligation was first recorded.

Recording a liability now for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination; the number of assets to be inspected, tested and mitigated; oil volumes; and contamination levels of equipment with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting current legislative and regulatory requirements. These include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions were approximately $112 million in 2009, based on an actuarial valuation effective December 31, 2006. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 7.25% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix remained at 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short term, the plan can experience aberrations in actual return. In 2009, the return on pension plan assets was higher than this long-term assumption, but was lower in 2008.

The discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2009, decreased to 6.50% from 7.25% used at December 31, 2008, in conjunction with increases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

Yields on AA corporate bonds decreased by approximately 50–180 basis points between December 31, 2008, and December 31, 2009. Based on the duration of the plan's liabilities, discount rates would be 6.50% per annum for each of the pension plan, for the post-retirement benefit plan and for the post-employment plan. The overall discount rate applied to all plans for liability valuation purposes as at December 31, 2009, was 6.50%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has increased from approximately 1.30% per annum as at December 31, 2008, to approximately 2.50% per annum as at December 31, 2009. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is too high to be used as a long-term assumption, and as such, has used a 2.00% per annum inflation rate for liability valuation purposes as at December 31, 2009.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $13 million per year and an increase in the year-end obligation of about $141 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill and Asset Impairment

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2009 and we determined that the carrying value of our goodwill has not been impaired.

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would be tested for impairment only in the event that the OEB disallowed recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated Telecom Business for indications of impairment. No asset impairments have been recorded to date for any of our businesses.

Status of Our Transition to International Financial Reporting Standards (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. In anticipation of this decision, we commenced our IFRS conversion project in 2007. The project's formal governance structure includes a steering committee consisting of senior level management from finance, information technology, treasury and our operations organizations. Project status reporting is provided to senior executive management and to the Audit and Finance Committee of our Board of Directors on a regular basis. An external expert advisor was engaged to assist with our IFRS conversion project.

The project has four separate phases: diagnostic, design and planning, solution development, and implementation. We completed the diagnostic phase in 2008. It involved a high level review and identification of the major differences between current GAAP and IFRS in all subject areas, resulting in the identification of the areas of accounting difference with the highest potential to significantly impact our company.

In 2009, we completed the design and planning and the solution development phases of our project, including substantial completion of all policy papers. We are currently engaged in the implementation phase which is the final phase of our project. Our teams are continuing to monitor progress relative to key milestones, monitor developments of the International Accounting Standards Board (IASB), update recommendations and develop financial reports. We continue to have recurring dialogue with our external auditors about possible outcomes of our project. We continue to evaluate the impacts of current and prospective IFRS on all of our business activities, including those of our subsidiaries and the impact on our entity-wide information system. We are simultaneously analyzing the impacts of changes on our disclosure controls and internal controls over financial reporting, our debt covenants and our performance measures. We continue to provide formal communications to our employees. We have completed numerous staff training sessions and will plan for future training sessions as necessary.

The areas with the highest potential to significantly impact our company, identified during the diagnostic phase, are rate-regulated assets and liabilities, fixed assets, payments in lieu of corporate income taxes, employee future benefits, as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS* (IFRS 1). The specific effects of choices under these standards are not determinable at this time as a result of the status of the IASB's project on rate-regulated activities which will have an impact on the accounting choices available in all of these areas.

In December 2008, the IASB added a project on rate-regulated activities to its agenda. In July 2009, the IASB issued an exposure draft detailing its proposals for standards for the accounting of rate-regulated activities. The exposure draft allows for the continued recognition of regulatory assets and liabilities on the Balance Sheet. In-scope assets and liabilities are proposed to be carried at the net present value of the expected future cash flows. The exposure draft makes an exception to the requirements of other IFRS standards by allowing capitalization of otherwise ineligible costs within fixed assets and intangible assets on the basis of the costs' inclusion in rate base. The IASB requested comments from interested observers on the exposure draft. Hydro One responded to the IASB's request for comment on November 24, 2009. The IASB received approximately 150 responses to its request for comment, which were very diverse in their opinions. As a result, the IASB staff has postponed presenting their analysis of the responses to the IASB, originally scheduled for January, to the Board's February meeting. The presentation to the IASB may include options for the next steps of the project. It is unclear at this time what the outcome of the IASB's deliberations will be and how reporting standards will be impacted.

The effect of the exposure draft on rate-regulated activities (RRA ED) will impact the determination of which indirect costs incurred on in-progress construction projects can be capitalized. This may affect our choices under IFRS 1. It is unclear at this time whether the continuation of accounting for expenditures related to employer sponsored pension plans on a cash basis would be permissible. Similarly, we are assessing our options with respect to the recognition of accumulated, unamortized gains and losses associated with employment benefits other than pension. Currently, the possible alternatives to account for these pension and other employee benefit amounts include charging unamortized gains and losses immediately upon adoption under IFRS 1, or recognizing an adjustment to those amounts retrospectively to comply with IAS 19, *Employee Benefits*. Our policy choice is contingent upon the outcome of the RRA ED. In accordance with IAS 12, *Income Taxes*, we have determined that there is no potential for a significant impact for this class of transactions based upon contingent outcomes regarding transactions for payments in lieu of corporate income taxes. If the RRA ED is adopted as is, we plan to continue to record taxes on a cash basis instead of the liability method for the regulated businesses.

On October 14, 2009, the Public Sector Accounting Board (PSAB) released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. On December 14, 2009, the PSAB issued an exposure draft proposing to remove the requirement for government organizations adhering to IFRS to also apply additional public sector financial reporting standards, currently Public Sector Accounting Handbook Section 3270. The effective date for the proposed changes is January 1, 2011.

On September 25, 2009, the Canadian Securities Administrators' staff communicated their view that all registrants will be required to report under IFRS commencing January 1, 2011. We are a registrant as a result of our public debt.

In May 2008, the OEB initiated a consultative process to determine the nature of any changes to regulatory reporting requirements in response to IFRS. The OEB held public meetings and a formal stakeholder conference in May 2009. We participated at each opportunity offered to the public to communicate with the OEB. On July 28, 2009, the OEB released some preliminary views on how regulatory reporting requirements will change in response to IFRS. The OEB has initiated a second phase of its consultative process to amend certain regulatory instruments. We are continuing to assess the impact of the OEB's report and other recommendations on our IFRS conversion project.

Disclosure Controls and Internal Controls over Financial Reporting

In 2008, we began transitioning our major financial systems to a SAP enterprise-wide platform as part of the entity-wide information system replacement and improvement project. A formal project governance structure is in place to ensure an effective transition of the information technology systems and business processes. The governance structure includes a steering committee consisting of senior levels of management which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

In 2008, we successfully implemented the first phase of the supply chain, asset and work management modules in SAP. During the third quarter of 2009, we successfully implemented various finance, human resources, payroll and investment management SAP modules. The reporting tool Business Intelligence/Business Warehouse (BI/BW) was also implemented. This implementation included new controls over internal controls over financial reporting and the replacement of other controls in the previous environment. Our process documentation has been updated and the design and effectiveness of the controls have been tested.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2009, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and that they operated effectively as at December 31, 2009. Further, our Certifying Officers have also certified that internal controls over financial reporting operated effectively as at December 31, 2009.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2007, 2008 and 2009. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statement of Operations

Year ended December 31 (Canadian dollars in millions, except earnings per common share)	**2009**	2008	2007
Revenues[1]	**4,744**	4,597	4,655
Net income[1]	**470**	498	399
Basic and fully diluted earnings per common share	**4,528**	4,797	3,809

Consolidated Balance Sheet

Year ended December 31 (Canadian dollars in millions, except cash dividends per share)	**2009**	2008	2007
Total assets	**15,810**	13,878	12,786
Total long-term debt	**6,881**	6,133	5,603
Cash dividends per common share	**1,700**	2,410	3,070
Cash dividends per preferred share	**1.375**	1.375	1.375

[1] As a result of the OEB's December 18, 2008 decision on Hydro One Networks' distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008, reflecting growth in the work program requirements and investment in capital infrastructure.

OUTLOOK

To achieve our vision to be the leading electricity delivery company in North America, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, innovation and connecting renewable energy, reliability, protection of the environment, recruitment and knowledge retention, shareholder value and productivity. We work in an environment where safety is of the utmost importance. Our people underpin everything we do, and as such, we remain resolute in our commitment to safety. We will continue to focus our efforts to improve our customers' satisfaction by maintaining operational excellence through our efforts to innovate and to renew transmission and distribution systems. In particular, we will focus on targeted investments to address overloaded or aging equipment at customer delivery points, power quality and network performance necessary to improve reliability, which will in turn, improve customer satisfaction.

The GEA introduced a new paradigm for Ontario's energy industry. The need to rapidly reduce the energy sector's carbon footprint dominates current environmental decision-making, leading to high expectation for immediate action and expansion of clean energy supply. Emerging technologies and the need to connect clean and renewable generation challenges our Transmission and Distribution Businesses to recalibrate and establish a more flexible and smart electricity grid.

We are planning significant investments in transmission and distribution infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability in the public interest. Our investment plan supports the achievement of the Province's coal shutdown, renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs and facilitates the integration of new supply.

In 2009, we filed a cost of service application with the OEB for 2010 and 2011 distribution rates, seeking revenue requirements of approximately $1,196 million and $1,295 million for 2010 and 2011, respectively. The revenue requirements requested, if approved, will continue to support our work programs necessary to sustain our critical infrastructure, increase reliability through enhanced forestry management, support the smart meter requirements and invest in a sustainable electricity system that supports renewable generation.

We are currently preparing evidence to support our upcoming transmission rate application for the years 2011 and 2012, which is anticipated to be filed with the OEB in the first quarter of 2010. This application will continue to support aging critical infrastructure, area supply projects and the Government policy objectives.

The actual timing and expenditures in our plan are predicated on obtaining various approvals including OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Further, we have made assumptions in the plan regarding cost responsibility and funding, consistent with the GEA regulations and amended TSC and DSC. We have prepared business plans, regulatory filings and future capital expenditures on the basis that rate-regulated accounting will continue under IFRS for the period commencing 2011.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and ensuring that environmental factors are considered in making our business decisions. Our commitment to the environment has been recognized by Canada's Energy, Environment and Excellence group and *Corporate Knights* magazine.

Key enablers of the successful implementation of our work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our association with universities, colleges and our unions, as well as skills development and retention. Significant retirement projections and increasing work volumes will result in an unprecedented number of new hires in the near term. With regard to materials, we are seeing increasing lead times and costs as market shortages emerge globally. Consequently, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2009, the Government announced its intention to make the exemption from the electricity transfer tax permanent for transfers of electricity assets within the public sector. We have and will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. The investment plan does not include any funding for any LDC acquisitions or divestitures.

We will continue to increase enterprise value through productivity improvements and cost-effectiveness driven by technology. Over the last two years, we have replaced most of our core systems with an enterprise-wide information technology system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. In addition, significant opportunity resides with smart meters and the proliferation of a smart grid, including energy efficiency, demand response and distributed-resources technologies. Through the outlook period, we anticipate no changes to our role within the industry and expect that our financial returns will be sufficient to maintain our credit quality.

Appointment of George L. Cooke

On January 26, 2010, George L. Cooke was elected to our Board of Directors. Mr. Cooke is President and Chief Executive Officer of The Dominion of Canada General Insurance Company.

FORWARD LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements about our strategy and our performance measures and targets; statements related to the IPSP; statements about smart meters including their capabilities, their timing of installation and our focus on building an advanced distribution solution that will leverage our smart meter investment; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including the impacts of changes to codes, licences, rules, new regulatory guidelines, tariff rate changes, cost recovery, return on equity, rate structures, revenue requirements and impacts on an average customer's total bill; expectations regarding the timing and content of applications to, hearings with and decisions from the OEB and other regulatory bodies; expectations regarding our Green Energy Plan filed with the OEB and the impact of the GEA including future capital projects and cost recoveries flowing there from; expectations regarding future renewable energy generation; statements regarding our liquidity and capital resources and their use; expectations regarding our financing activities, including our capital management objectives and our ability to access the capital markets; expectations regarding the results of our on-going and planned projects and/or initiatives and their completion dates; statements regarding expected future capital expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commitments; statements regarding the effect of load on our revenue including the anticipated impact of CDM programs, embedded generation growth and the below-average growth of the Ontario economy; the effect of interest rates on our revenue requirements and results of operations; statements regarding the estimated impact of changes in the forecast long-term Government of Canada bond yield on our results of operations; impacts to our business in respect of the adequacy and timing of supply of materials, supplies and services and credit risk of our counter-parties; expectations regarding future pension contributions and the performance of our pension plan; the possibility of the Province making declarations pursuant to our memorandum of agreement with them; statements regarding possible future actions of the Province and regulatory bodies; expectations regarding connections of new generation to our transmission and distribution systems; expectations regarding asset condition; statements regarding workforce demographics and the market for skilled labour; statements regarding the amount and timing of future estimated environmental expenditures, including with respect to LAR and PCBs; statements about future asbestos removal expenditures; expectations regarding our information technology strategy and enterprise reporting system; the possibility that we could in future decide to issue foreign currency denominated debt; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements about our outsourcing arrangement with Inergi LP; statements regarding provincial ownership of our transmission corridors; statements about critical accounting estimates; statements about IFRS, our conversion to IFRS and the effect of the rate-regulated accounting exposure draft on our company; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, our credit rating and credit quality and structural changes to our company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will," "believe," "seek," "estimate," "goal," "aim," "target," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission Businesses; a stable regulatory environment; the preparation of business plans, regulatory filings and future capital expenditures on the basis that commencing 2011 rate-regulated accounting will continue to exist under IFRS; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the impact of the GEA, including unexpected expenditures arising there from;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as, potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the timing and results of regulatory decisions regarding our revenue requirements, cost recovery and rates, as well as, changes to rules under various regulatory body review;
- the potential impact of CDM programs on our load and our revenues;
- unanticipated changes in electricity demand or in our costs;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk that we will be unable to source the materials necessary to support our work programs;
- the risks related to our work force demographic and our potential inability to attract and retain qualified personnel;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risk of currently undetermined future asbestos removal costs;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risks associated with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risks associated with changes in interest rates;
- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated;
- the impact of the ownership by the Province of lands underlying our transmission system; and
- the impact of the final outcome of the exposure draft on rate-regulated accounting under IFRS.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in this Management's Discussion and Analysis (MD&A). You should review such section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to provide context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at February 11, 2010. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 11, 2010.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition internal and disclosure controls have been documented, evaluated, tested and identified consistent with National Instrument 52-109 (Bill 198). An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Auditors' Report, which appears on page 37, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer and Senior Vice-President and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Laura Formusa
President and Chief Executive Officer

Sandy Struthers
Senior Vice-President and Chief Financial Officer

Auditors' Report

To the Shareholder of Hydro One Inc.

We have audited the consolidated balance sheets of Hydro One Inc. (the Company) as at December 31, 2009 and December 31, 2008, and the consolidated statements of operations and comprehensive income, retained earnings, accumulated other comprehensive income, and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP
Chartered Accountants,
Licensed Public Accountants

Toronto, Canada
February 11, 2010

Consolidated Statements of Operations and Comprehensive Income

Year ended December 31 (Canadian dollars in millions, except per share amounts)	**2009**	2008
Revenues		
Transmission (Note 15)	**1,147**	1,212
Distribution (Note 15)	**3,534**	3,334
Other	**63**	51
	4,744	4,597
Costs		
Purchased power (Note 15)	**2,326**	2,181
Operation, maintenance and administration (Note 15)	**1,057**	965
Depreciation and amortization (Note 3)	**537**	548
	3,920	3,694
Income before financing charges and provision for payments in lieu of corporate income taxes	**824**	903
Financing charges (Note 4)	**308**	292
Income before provision for payments in lieu of corporate income taxes	**516**	611
Provision for payments in lieu of corporate income taxes (Notes 5 and 15)	**46**	113
Net income	**470**	498
Other comprehensive loss	**-**	(1)
Comprehensive income	**470**	497
Basic and fully diluted earnings per common share *(Canadian dollars)* (Note 14)	**4,528**	4,797

Consolidated Statements of Retained Earnings

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Retained earnings, January 1	**1,497**	1,258
Change in accounting policy for the recognition of future income tax assets and liabilities (Note 2)	**12**	–
Net income	**470**	498
Dividends (Note 14)	**(188)**	(259)
Retained earnings, December 31	**1,791**	1,497

See accompanying notes to Consolidated Financial Statements.

Consolidated Statements of Accumulated Other Comprehensive Income

Year ended December 31 (Canadian dollars in millions)	2009	2008
Accumulated other comprehensive income, January 1	**(10)**	(9)
Other comprehensive loss	**–**	(1)
Accumulated other comprehensive income, December 31	**(10)**	(10)

Consolidated Balance Sheets

December 31 (Canadian dollars in millions)	2009	2008
Assets		
Current assets:		
Cash	**–**	16
Accounts receivable (net of allowance for doubtful accounts – $25 million; 2008 – $23 million) (Note 15)	**843**	754
Regulatory assets (Note 8)	**72**	64
Materials and supplies	**21**	19
Future income tax assets (Notes 2 and 5)	**21**	2
Other	**16**	18
	973	873
Fixed assets (Notes 2 and 6):		
Fixed assets in service	**18,407**	17,334
Less: accumulated depreciation	**6,815**	6,418
	11,592	10,916
Construction in progress	**1,256**	912
Future use land, components and spares	**150**	132
	12,998	11,960
Other long-term assets:		
Deferred pension asset (Note 12)	**424**	441
Regulatory assets (Notes 2 and 8)	**1,033**	291
Goodwill	**133**	133
Intangible assets (net of accumulated amortization) (Notes 2 and 7)	**218**	162
Future income tax assets (Notes 2 and 5)	**18**	–
Other	**13**	18
	1,839	1,045
Total assets	**15,810**	13,878

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets (continued)

December 31 (Canadian dollars in millions)	**2009**	2008
Liabilities		
Current liabilities:		
Bank indebtedness	**26**	–
Accounts payable and accrued charges (Notes 13 and 15)	**800**	793
Regulatory liabilities (Notes 2 and 8)	**100**	43
Accrued interest	**74**	64
Short-term notes payable	**55**	–
Long-term debt payable within one year (Note 9)	**600**	400
	1,655	1,300
Long-term debt (Note 9)	**6,281**	5,733
Other long-term liabilities:		
Employee future benefits other than pension (Note 12)	**940**	908
Regulatory liabilities (Notes 2 and 8)	**504**	564
Future income tax liabilities (Notes 2 and 5)	**693**	–
Environmental liabilities (Note 13)	**303**	237
Long-term accounts payable and other liabilities	**16**	12
	2,456	1,721
Total liabilities	**10,392**	8,754
Contingencies and commitments (Notes 17 and 18)		
Shareholder's equity (Note 14)		
Preferred shares (authorized: unlimited; issued: 12,920,000)	**323**	323
Common shares (authorized: unlimited; issued: 100,000)	**3,314**	3,314
Retained earnings	**1,791**	1,497
Accumulated other comprehensive income	**(10)**	(10)
Total shareholder's equity	**5,418**	5,124
Total liabilities and shareholder's equity	**15,810**	13,878

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Walter Murray
Chair, Audit and Finance Committee

Consolidated Statements of Cash Flows

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Operating activities		
Net income	**470**	498
Environmental expenditures	**(9)**	(14)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	**487**	502
Revenue difference deferral account	**–**	(73)
Regulatory liability refund account	**(24)**	30
Smart meters	**(16)**	1
External revenue variance account	**12**	–
Revenue recovery account	**7**	(25)
Other regulatory asset and liability accounts	**(13)**	6
Future income taxes	**16**	–
Amortization of debt costs	**–**	2
	930	927
Changes in non-cash balances related to operations (Note 16)	**(38)**	125
Net cash from operating activities	**892**	1,052
Financing activities		
Long-term debt issued	**1,150**	1,050
Long-term debt retired	**(400)**	(540)
Short-term notes payable	**55**	–
Dividends paid	**(188)**	(259)
Other	**2**	3
Net cash from financing activities	**619**	254
Investing activities		
Capital expenditures		
Fixed assets	**(1,473)**	(1,185)
Intangible assets	**(93)**	(99)
	(1,566)	(1,284)
Other assets	**13**	6
Net cash used in investing activities	**(1,553)**	(1,278)
Net change in cash and cash equivalents	**(42)**	28
Cash and cash equivalents, January 1	**16**	(12)
Cash and cash equivalents, December 31 (Note 16)	**(26)**	16

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the OEB.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Inc. (HODS), Hydro One Lake Erie Link Management Inc. (HOLELMI) and Hydro One Lake Erie Link Company Inc. (HOLELCo).

HODS was dissolved on August 29, 2008. Effective December 13, 2007, upon approval of the resolution to apply for the dissolution of HODS, its interests in HOLELMI and HOLELCo were distributed to Hydro One.

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-Setting

The rates of the Company's electricity Transmission and Distribution Businesses are subject to regulation by the Ontario Energy Board (OEB).

Transmission

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, approved all operating and capital expenditures for 2007 and 2008. However, the decision resulted in a reduction in the approved return on equity from 9.88% to 8.35%. The OEB also approved final amounts and disposition treatments for certain regulatory liabilities including the revenue difference deferral account (RDDA), the earnings sharing mechanism (ESM) and export and wheeling fees, as well as the transmission market ready regulatory asset.

As part of a joint proceeding involving all transmitters in Ontario, on October 17, 2007, the OEB approved Uniform Transmission Rates (UTRs) for implementation on November 1, 2007, through to December 31, 2008. The new rates fully reflect the approved changes to our revenue requirement and charge determinants.

On May 30, 2008, Hydro One Networks submitted an application to the OEB to adjust UTRs effective January 1, 2009. On August 28, 2008, the OEB approved the application allowing Hydro One Networks to recover revenues consistent with the OEB-approved 2008 revenue requirement, which reflected the full repayment to customers of the amounts recorded in the ESM and the RDDA at the end of 2008.

To achieve the necessary funding in support of required infrastructure, Hydro One Networks filed a transmission rate application for 2009 and 2010 rates in September 2008. The application sought OEB approval for revenue requirement of approximately $1,233 million and $1,341 million, based on a return on equity of 8.53% and 9.35% for 2009 and 2010, respectively. On May 28, 2009, the OEB issued its decision in respect of this application. The decision, which was effective July 1, 2009, resulted in a reduced revenue requirement of $1,180 million and $1,240 million in 2009 and 2010, respectively, primarily due to a lower approved return on equity. The OEB decision disallowed development capital expenditures of $180 million for 2010, but agreed to reconsider the projects if additional evidence was provided. On September 4, 2009, Hydro One Networks filed the additional evidence on two projects amounting to approximately $160 million in capital expenditures. The OEB approved the supplemental evidence for inclusion in Hydro One Networks' 2010 rates. This resulted in a revised revenue requirement of $1,257 million for 2010, on the basis of an updated return on equity of 8.39% for 2010.

Distribution

In 2006, the OEB initiated a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process included a formulaic approach to establishing 2007 rates with a rate re-basing approach to be staggered across all Ontario distributors between 2008 and 2010.

In accordance with the OEB's multi-year distribution rate-setting plan, Hydro One Networks submitted the revenue requirement portion of its 2008 cost of service application on August 15, 2007. This application sought the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64%, and included a plan to reduce the number of rate classes for its customers and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes.

On December 18, 2008, the OEB issued a decision approving substantially all work program expenditures effective May 1, 2008, for implementation on February 1, 2009. The OEB also approved recovery of our smart meter expenditures made prior to the end of 2007. The decision approved the establishment of the revenue recovery account (RRA) to record the revenue differential between existing distribution rates and new rates. The RRA is being recovered over a 27-month period commencing February 1, 2009 and ending April 30, 2011.

In late 2008, Hydro One Networks filed an incentive regulation application for 2009 rates, with an update filed in January 2009, to reflect the impact of the 2008 distribution rate decision. The application was filed on the basis of the OEB's third generation IRM process which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in service beyond a prescribed threshold. On May 13, 2009, the OEB released its decision approving the basic IRM increase and the $1.65 per month per metered customer for smart meters. The revised rates were approved effective May 1, 2009, with an implementation date of June 1, 2009.

On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's second generation IRM policy which incorporates an OEB-approved formula that considers inflation and efficiency targets. On March 19, 2008, the OEB released its decision. The revised rates, including an amount of $0.67 cents per month per metered customer for smart meters, were approved with an implementation date of May 1, 2008.

On November 7, 2008, Hydro One Brampton filed an application on the same basis for 2009 distribution rates. On March 13, 2009, the OEB released it decision and approved the submission on the basis of its second generation IRM policy. The revised rates, including an amount of $1.00 per month per metered customer for smart meters, were approved for implementation effective May 1, 2009.

On August 29, 2008, Hydro One Remote Communities filed a 2009 cost of service rate application proposing an increase of about $10 million over the 2006 approved revenue requirement as a result of increased fuel costs. On April 30, 2009, the OEB issued a decision regarding this rate application approving all work program expenditures effective May 1, 2009.

Regulatory Accounting

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 8.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2009, amounted to $434 million (2008 – $383 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, *Income Taxes* and CICA Handbook Section 1100, *Generally Accepted Accounting Principles*. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income tax assets and liabilities of rate-regulated enterprises.

For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Adjustments to retained earnings were recorded for the cumulative earnings impact of future income tax assets and liabilities as at December 31, 2008 that are excluded from the rate-setting process.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the statement of operations and comprehensive income.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

Materials and Supplies

Materials and supplies represent consumables, spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land; major components and spare parts; and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets in perpetuity, no asset retirement obligation exists. If, at some future date, a particular site is shown not to meet the perpetuity assumption, it will be reviewed to determine if an asset retirement obligation exists. If it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity such as transmission lines; support structures; foundations; insulators; connecting hardware and grounding systems; and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction and Development in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction and intangible assets under development, based on the OEB's approved allowance for funds used during construction (2009 – 5.89%; 2008 – 5.32%).

Depreciation and Amortization

The capital costs of fixed assets and intangible assets, primarily consisting of applications software, are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically undergoes an external review of its fixed asset and intangible depreciation and amortization rates, as required by the OEB. The last review resulted in changes to rates effective January 1, 2007. A summary of depreciation and amortization rates for the various classes of assets is included below:

	Depreciation and Amortization Rates (%)	
	Range	Average
Transmission	1%–3%	2%
Distribution	1%–13%	2%
Communication	1%–13%	5%
Administration and service	1%–20%	7%

The costs of intangible assets are primarily included within the administration and service classification above and these assets are amortized on a straight-line basis. Amortization rates for computer applications software and other assets range from 9% to 11%.

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation or amortization, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation or amortization expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed or intangible assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations. The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the Distribution Business segment.

Intangible Assets

Intangible assets represent computer applications software and other assets. These assets are carried at cost net of accumulated amortization. The cost of computer applications is comprised of materials, labour, overheads and the OEB-approved allowance for funds used during construction applicable to development activities within the regulated businesses.

Effective January 1, 2009, the Company adopted CICA Handbook Section 3064, *Goodwill and Intangible Assets*, which replaced CICA Handbook Section 3062, *Goodwill and Other Intangible Assets* and CICA Handbook Section 3450, *Research and Development Costs*. The new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill and other intangible assets.

As a result of adopting this new accounting standard, the Company reclassified computer applications software previously classified as fixed assets and reclassified other assets previously classified as long-term other assets to intangible assets.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

Financial Instruments

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges and the change in fair value on existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the hedged debt.

Financial Assets and Liabilities

All financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Short-term investments	Held-to-maturity/Held-for-trading
Fixed-to-floating interest rate swap	Not classified
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Accounts payable	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (unless otherwise specified)	Other liabilities
MTN Series 14 Note	Not classified

Short-term investments are generally classified as held-to-maturity; however, the Company allows itself the possibility to classify pools of short-term investments as held-for-trading where there is not the intention of holding a pool of assets to their maturity. Documentation of the short-term investment classification is made on inception.

Where long-term debt is designated as part of a hedging relationship, as in the case of the MTN Series 14 Note, the long-term debt, and related hedging instrument, are not classified.

All financial instrument transactions are recorded at trade date.

Derivatives and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used; in which case, changes in fair value are recorded in OCI to the extent that the hedge is effective.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documentation includes its risk management objective for establishing the hedging relationship, the identification of hedged and hedging item, the nature of the specific risk exposure being hedged, and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging items that are used are effective in offsetting changes in fair values or cash flows of the hedged items.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method.

Financial Instrument Disclosures

Effective for the 2009 annual reporting period, the Company adopted amendments to the CICA Handbook Section 3862, *Financial Instruments Disclosure*. This amended section improves financial instrument fair value measurement and liquidity risk management disclosures. The amendments require an entity to classify fair value measurements using a fair value hierarchy in levels ranging from 1 to 3 that reflect the significance of the inputs used in making these measurements. The amendments also provide clarification about the required liquidity risk disclosures. Upon application by the Company, the fair value hierarchy level used in the determination of the fair market value of the long-term debt has been disclosed in Note 10.

Employee Future Benefits
Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs
Hydro One records a liability for the estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyls (PCBs) contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recorded to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates
The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

Emerging Accounting Changes

International Financial Reporting Standards (IFRS)
On February 13, 2008, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. As such, the Company will apply IFRS to its financial statements ending December 31, 2011, with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The International Accounting Standards Board (IASB) issued an exposure draft on rate-regulated activities in July 2009. Responses to the IASB's request for comment varied substantially. As a result, the IASB staff has postponed presenting their analysis of the responses to the IASB until February 2010. This presentation may include options for the next steps of the rate-regulated activities project. It is unclear at this time what the outcome of the Board's deliberations will be and how that will impact the Company's reporting under IFRS. The effect on the Company's future financial position and results of operations are not estimable at this time.

3. Depreciation and Amortization

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Depreciation of fixed assets in service	**418**	404
Amortization of intangible assets	**36**	14
Fixed asset removal costs	**50**	46
Amortization of regulatory and other assets	**33**	84
	537	548

4. Financing Charges

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Interest on short-term notes payable	**–**	2
Interest on long-term debt payable	**369**	331
Interest accreted on regulatory accounts	**1**	2
Less: Interest capitalized on construction and development in progress	**(58)**	(36)
Interest earned on investments	**(1)**	(7)
Other	**(3)**	–
	308	292

5. Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Income before provision for PILs	**516**	611
Federal and Ontario statutory income tax rate	**33.00%**	33.50%
Provision for PILs at statutory rate	**170**	205
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Transmission amounts paid but not recognized for accounting purposes	**–**	(34)
Capital cost allowance in excess of depreciation and amortization	**(74)**	(32)
Retail settlement variance accounts	**4**	15
Pension contributions in excess of pension expense	**(15)**	(13)
Overheads capitalized for accounting but deducted for tax purposes	**(14)**	(12)
Interest capitalized for accounting purposes but deducted for tax purposes	**(19)**	(11)
Distribution amounts paid but not recognized for accounting purposes	**–**	(8)
Employee future benefits other than pension expense in excess of cash payments	**1**	6
Environmental expenditures	**(3)**	(5)
Other	**(6)**	–
Net temporary differences	**(126)**	(94)
Net permanent differences	**2**	2
Total income tax provision for PILs	**46**	113
Current income tax provision for PILs	**30**	113
Future income tax provision for PILs	**16**	–
Total income tax provision for PILs	**46**	113
Effective income tax rate	**8.91%**	18.49%

The provision for payments in lieu of current income taxes of $30 million represents the amount payable to the OEFC with respect to current year earnings. There is no outstanding balance due to the OEFC (2008 – $nil).

The provision for payments in lieu of future income taxes of $16 million reflects the increase in the liability for payments in lieu of future income taxes that are not expected to be recovered from the Company's customers through future rates. The increase in the liability for payments in lieu of future income taxes that is expected to be recovered from the Company's customers through future rates has resulted in an increase in regulatory assets.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

December 31 (Canadian dollars in millions)	2009
Future income tax assets	
Capital cost allowance in excess of depreciation and amortization	6
Employee future benefits other than pension expense in excess of cash payments	4
Retail settlement variance accounts	3
Environmental expenditures	3
Other	3
Total future income tax assets	19
Less: current portion	1
	18

December 31 (Canadian dollars in millions)	2009
Future income tax liabilities	
Capital cost allowance in excess of depreciation and amortization	(1,019)
Employee future benefits other than pension expense in excess of cash payments	315
Environmental expenditures	82
Transmission and distribution amounts received but not recognized for accounting purposes	(73)
Goodwill	25
Retail settlement variance accounts	5
Other	(8)
Total future income tax liabilities	(673)
Less: current portion	20
	(693)

As at December 31, 2009, payments in lieu of future income tax liabilities of $461 thousand (2008 – $4 million), based on substantively enacted income tax rates and laws, have not been recorded, as it is more likely than not that the assets will not be realized in the future.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets	Accumulated Depreciation	Construction in Progress	Total
2009				
Transmission	**9,485**	**3,455**	**956**	**6,986**
Distribution	**6,773**	**2,392**	**220**	**4,601**
Communication	**806**	**376**	**54**	**484**
Administration and service	**1,007**	**510**	**26**	**523**
Easements	**486**	**82**	**–**	**404**
	18,557	**6,815**	**1,256**	**12,998**
2008				
Transmission	8,995	3,307	659	6,347
Distribution	6,317	2,266	165	4,216
Communication	773	342	54	485
Administration and service	894	426	34	502
Easements	487	77	–	410
	17,466	6,418	912	11,960

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $55 million in 2009 (2008 – $33 million).

7. INTANGIBLE ASSETS

December 31 (Canadian dollars in millions)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2009				
Computer applications software	**379**	**166**	**3**	**216**
Other assets	**5**	**3**	**–**	**2**
	384	**169**	**3**	**218**
2008				
Computer applications software	270	162	51	159
Other assets	5	2	–	3
	275	164	51	162

Financing costs are capitalized on intangible assets under development, including allowance for funds used during construction on regulated assets, and were $3 million in 2009 (2008 – $3 million).

8. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	2009	2008
Regulatory assets:		
Regulatory future income tax asset	**683**	–
Environmental	**327**	253
Rural and remote rate protection variance account	**24**	17
Regulatory asset recovery account II	**19**	43
Smart meters	**19**	3
Revenue recovery account	**18**	25
Other	**15**	14
Total regulatory assets	**1,105**	355
Less: current portion	**72**	64
	1,033	291

December 31 (Canadian dollars in millions)	2009	2008
Regulatory liabilities:		
Deferred pension	**424**	441
Regulatory liability refund account	**49**	73
Regulatory future income tax liability	**32**	–
Retail settlement variance accounts	**29**	31
Regulatory asset recovery account I	**23**	19
Export and wheeling fees	**15**	27
External revenue variance account	**12**	–
Other	**20**	16
Total regulatory liabilities	**604**	607
Less: current portion	**100**	43
	504	564

Regulatory Assets

Regulatory Future Income Tax Asset and Liability

Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts set up for taxes to be recovered through future rates. As a result the provision for PILs would have been higher by approximately $127 million (2008 – $79 million) including the impact of a change in substantively enacted tax rates.

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 13). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2008, this regulatory asset increased by $195 million to reflect the additional liability recorded in respect of the issuance of Environment Canada's final PCB regulations. In 2009, the regulatory asset increased by $30 million to reflect related increases in the Company's PCB liability and by $40 million for an increase in the land assessment and remediation (LAR) liability.

The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, operation, maintenance and administration expenses would have been higher by $70 million (2008 – $195 million). In addition, amortization expense in 2009 would have been lower by $9 million (2008 – $14 million) and financing charges would have been higher by $13 million (2008 – $7 million).

Rural and Remote Rate Protection Variance Account (RRRP)
Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. In 2002, the OEB approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account to be disposed of at a later date.

Regulatory Asset Recovery Account II (RARA II) or Rider 2
On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate-regulated accounting, amortization expense in 2009 would have been lower by $23 million (2008 – $23 million). In addition, related financing charges would have remained the same (2008 – higher by $2 million).

Smart Meters
On March 21, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and approved a monthly rate adder charge of $0.27 and $0.28 cents per residential metered customer for Hydro One Networks and Hydro One Brampton, respectively. The Company recorded a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters, less recoveries received from the rate adder. Effective May 1, 2007, the OEB increased the monthly adder to $0.93 cents and $0.67 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively.

On August 8, 2007, the OEB issued its decision allowing certain expenditures incurred by Hydro One Networks and Hydro One Brampton associated with minimum functionality for advanced metering infrastructure to be recovered and allowing certain capital expenditures to be included in rate base. As a result of this decision, the Company discontinued recording its smart meter expenditures as regulatory assets and instead began recording such expenditures as capital expenditures or as operation, maintenance and administration costs as appropriate. This OEB decision also required that revenues for smart meter expenditures not yet reviewed and approved, be recorded based upon a calculated revenue requirement in the same regulatory deferral account as amounts received under the approved smart meter rate adders. As a result, the difference between revenue recorded on this basis and actual recoveries received under existing rate adders is reflected as the carrying value of the regulatory asset account.

On December 18, 2008, as part of the OEB's decision on 2008 distribution rates, the OEB approved the recovery of certain excess functionality expenditures and the under-recovery of smart meter minimum functionality expenditures (revenue requirement net of revenue received from the monthly rate adder). The expenditures related to excess functionality are being recovered through the regulatory liability refund account.

Effective May 1, 2009, the OEB increased the respective monthly rate adders for Hydro One Brampton and Hydro One Networks' residential customers to $1.00 and $1.65 per month per metered customer. Hydro One Networks, as part of its application for 2010 and 2011 distribution rates, has requested the approval for the disposition of costs exceeding minimum functionality and the under-recovery of smart meter minimum functionality expenditures (revenue requirement net of revenue received from the monthly rate adder) through to December 31, 2008.

Revenue Recovery Account (RRA) or Rider 4
On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. The approved rates were effective May 1, 2008, with an implementation date of February 1, 2009. The OEB approved the establishment of the RRA to record the revenue differential between existing distribution rates and the new rates. The OEB ordered that the approved revenue requirement be retroactively recovered, through a rate rider, over a period of 27 months commencing February 1, 2009, and ending April 30, 2011.

Regulatory Liabilities

Deferred Pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate-regulated accounting, operating, maintenance and administration expense would have been higher by $9 million (2008 – lower by $38 million).

Regulatory Liability Refund Account (RLRA) or Rider 3

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of the decision, the OEB also approved certain distribution-related deferral account balances sought by Hydro One in its application including retail settlement variance amounts, deferred tax changes, OEB costs and smart meters. Amounts for which recovery was approved represented balances incurred prior to April 30, 2008, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over a 27-month period from February 1, 2009 to April 30, 2011.

Retail Settlement Variance Accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The OEB's December 9, 2004 decision allowed for recovery of RSVA accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of RSVA accumulated since January 1, 2004, and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The OEB's December 18, 2008 decision allowed for recovery of RSVA accumulated since May 1, 2006 through to April 30, 2008, inclusive of interest, within the RLRA. Hydro One Networks has accumulated a net liability in its RSVA since May 1, 2008.

Regulatory Asset Recovery Account I (RARA I) or Rider 1

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I included Distribution Business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. Hydro One Networks has accumulated a net liability in its RARA I account since May 1, 2008, due to continuance of the rate rider. In the absence of rate-regulated accounting, amortization expense in 2009 would have remained the same (2008 – lower by $5 million).

Export and Wheeling Fees

Consistent with the IESO's Market Rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of these export and wheeling fees, plus interest, were taken into consideration in the revenue requirement of Hydro One Networks' Transmission Business as part of the Company's transmission rate application filed with the OEB in September 2006. On August 16, 2007, the OEB issued its decision in respect of the Company's transmission rate application and approved final amounts and disposition treatments for the export wheeling fees. The export wheeling fees will be factored into rates over a four-year period ending December 31, 2010.

External Revenue Variance Account

On May 28, 2009, the OEB issued its decision regarding the 2009 and 2010 rates for the Transmission Business of Hydro One Networks. As part of the decision, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use and external revenue from station maintenance and engineering and construction work. These revenue sources are an offset to the Company's revenue requirement, and as such, the OEB requested the establishment of new variance accounts to capture any difference between the forecasted and actual revenues from these sources of external revenue. The balance reflects the excess of 2009 external revenue compared to the OEB-approved forecast.

9. DEBT

December 31 (Canadian dollars in millions)	**2009**	2008
Long-term debt:		
3.95% notes due 2009	**–**	400
7.15% debentures due 2010	**400**	400
3.89% notes due 2010	**200**	100
4.08% notes due 2011[1]	**250**	250
6.40% notes due 2011	**250**	250
5.77% notes due 2012	**600**	600
5.00% notes due 2013	**600**	400
3.13% notes due 2014	**250**	–
4.64% notes due 2016	**450**	450
5.18% notes due 2017	**600**	600
7.35% debentures due 2030	**400**	400
6.93% notes due 2032	**500**	500
6.35% notes due 2034	**385**	385
5.36% notes due 2036	**600**	600
4.89% notes due 2037	**400**	400
6.03% notes due 2039	**300**	–
5.49% notes due 2040	**300**	–
6.59% notes due 2043	**315**	315
5.00% notes due 2046	**75**	75
	6,875	6,125
Add: Unrealized hedged loss[1]	**11**	15
Less: Long-term debt payable within one year	**(600)**	(400)
Net unamortized premiums	**24**	20
Unamortized debt issuance costs	**(29)**	(27)
Long-term debt	**6,281**	5,733

[1] The unrealized hedged loss relates to the MTN Series 14 Note, which is accounted for as a fair value hedge. The unrealized hedged loss is offset by the $11 million (2008 – $15 million) unrealized gain on the related fixed-to-floating interest rate swap agreement.

Short-term debt represents promissory notes pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2009, the notes had a weighted average interest rate of 0.3%.

Hydro One has a $1,000 million committed and unused revolving standby credit facility with a syndicate of banks maturing in August 2010. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company issues notes for long-term financing under the Medium-Term Note (MTN) Program. On November 19, 2009, Hydro One issued new notes comprised of medium-term notes with a principal amount of $250 million having a five-year term and a coupon rate of 3.13%. The notes are due November 19, 2014.

The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million, of which, as at December 31, 2009, $2,750 million was remaining.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in Note 10.

10. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying value of financial instruments as at December 31, 2009 is as follows:

(Canadian dollars in millions)	Derivatives Used for Hedging	Other Financial Instruments Used for Hedging	Held-for-Trading	Loans and Receivables	Other Financial Liabilities
Financial assets					
Accounts receivable	–	–	–	843	–
Other assets (long-term)	11	–	–	2	–
Financial liabilities					
Bank indebtedness	–	–	–	–	26
Accounts payable and accrued charges[1]	–	–	–	–	795
Short-term notes payable	–	–	–	–	55
Long-term debt	–	261	–	–	6,620

[1] Accounts payable and accrued charges do not include income taxes payable or dividends payable.

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, provided in the table below, is based on unadjusted year-end market prices for the same or similar debt of the same remaining maturities. The fair value measurement of long-term debt is categorized as level 1 as the inputs used reflect quoted prices in an active market.

December 31 (Canadian dollars in millions)		**2009**		2008
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	**6,875**	**7,302**	6,125	6,128

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the MTN Series 14 Note, which is designated as part of a hedging relationship.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with the Company's capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency denominated debt which will be hedged back to Canadian dollars consistent with Hydro One's risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Distribution and Transmission Businesses is derived using a formulaic approach which is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A" rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecast long-term Government of Canada bond yield or the "A" rated Canadian utility spread used in determining the Company's rate of return would reduce its Transmission Business' results of operations by approximately $15 million and its Distribution Business' results of operations by approximately $10 million.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2009, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. As at December 31, 2009, there were no significant balances of accounts receivable due from any single customer.

In the year, the Company's provision for bad debts remained relatively unchanged at $25 million (2008 – $23 million). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2009, approximately 4% of the Company's accounts receivable were aged more than 60 days.

Hydro One manages its counter-party credit risk through various techniques including entering into transactions with highly rated counter-parties; limiting total exposure levels with individual counter-parties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counter-parties. The Company's credit risk for accounts receivable is limited to the carrying amount on the Consolidated Balance Sheet.

The Company uses derivative financial instruments to manage interest rate risk. Hydro One may enter into derivative agreements such as forward-starting pay-fixed-interest rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. No such agreements were outstanding as at December 31, 2009.

Derivative financial instruments result in exposure to credit risk since there is a risk of counter-party default. As at December 31, 2009, the only derivative instrument held by Hydro One was a $250 million fixed-to-floating interest rate swap agreement to convert the 4.08% coupon note maturing March 3, 2011, into a three-month variable rate debt. The counter-party credit risk exposure on the fair value of this interest rate swap contract is $11 million as at December 31, 2009.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations and the Company's Commercial Paper Program, under which it is authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days. The Commercial Paper Program is supported by committed revolving credit facilities with a syndicate of banks of $1,000 million as at December 31, 2009, maturing August 20, 2010. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at December 31, 2009, accounts payable and accrued charges in the amount of $800 million and the short-term notes payable in the amount of $55 million are expected to be settled in cash at their carrying amounts within the next year. Long-term debt maturing over the next 12 months is $600 million. Interest payments over the next 12 months on the Company's outstanding short-term notes payable and long-term debt amount to $372 million.

As at December 31, 2009, Hydro One has issued long-term debt in the amount of $6,875 million and the Company is required to make interest payments in the amount of $5,967 million. Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Interest Payments *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	600	372	6.1
2 years	500	345	5.2
3 years	600	324	5.8
4 years	600	289	5.0
5 years	250	259	3.1
	2,550	1,589	5.3
6–10 years	1,050	1,121	4.9
Over 10 years	3,275	3,257	6.1
	6,875	5,967	5.6

11. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, short-term notes payable, long-term debt and cash and cash equivalents. The Company's capital structure as at December 31, 2009 and December 31, 2008 was as follows:

(Canadian dollars in millions)	**2009**	2008
Short-term notes payable	**55**	–
Long-term debt payable within one year	**600**	400
Less: Cash and cash equivalents	**(26)**	16
	681	384
Long-term debt	**6,281**	5,733
Preferred shares	**323**	323
Common shares	**3,314**	3,314
Retained earnings	**1,791**	1,497
	5,428	5,134
Total capital	**12,390**	11,251

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash" and "bank indebtedness."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2009, Hydro One is in compliance with all of these covenants and limitations.

12. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2009 and 2008 was as follows:

	% of Plan Assets	
December 31	**2009**	2008
Equity securities	**63.3**	62.0
Debt securities	**32.9**	33.3
Other	**3.8**	4.7
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $88 million at December 31, 2009 and 2008.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario (FSCO) on September 20, 2007, effective for December 31, 2006, the Company contributed $112 million to its pension plan in respect of 2009 (2008 – $101 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on future investment returns and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2009, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans, was $155 million (2008 – $142 million).

Pension Asset Transfer

Effective March 1, 2002, Hydro One began receiving a range of services from Inergi LP (Inergi), including information technology, customer care, supply chain and certain human resources and financial services. In connection with this agreement, the Company transferred approximately 770 regular employees to Inergi. On March 10, 2008, the Company was granted consent from the FSCO to transfer pension assets and related pension liabilities for affected employees from the Hydro One Pension Plan to the Inergi Pension Plan. Under the agreement, the Company recognized a settlement of $21 million in its results of operations for the first quarter of 2008, inclusive of a related interest credit of $6 million. The pension asset transfer took place in the second quarter of 2008.

	Pension		Employee Future Benefits Other Than Pension	
Year ended December 31 (Canadian dollars in millions)	**2009**	2008	**2009**	2008
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**4,007**	5,077	**874**	1,094
Current service cost	**73**	98	**19**	22
Interest cost	**286**	277	**63**	60
Benefits paid	**(270)**	(272)	**(43)**	(41)
Plan amendments	**–**	–	**–**	–
Net actuarial loss (gain)	**644**	(1,173)	**91**	(261)
Accrued benefit obligation, December 31	**4,740**	4,007	**1,004**	874
Change in plan assets				
Fair value of plan assets, January 1	**3,836**	5,100	**–**	–
Actual return on plan assets	**642**	(1,121)	**–**	–
Reciprocal transfers[2]	**6**	21	**–**	–
Benefits paid	**(270)**	(272)	**–**	–
Employer's contributions[1]	**112**	101	**–**	–
Employees' contributions	**21**	20	**–**	–
Administrative expenses	**(11)**	(13)	**–**	–
Fair value of plan assets, December 31	**4,336**	3,836	**–**	–
Funded status				
Unfunded benefit obligation	**(404)**	(171)	**(1,004)**	(874)
Unamortized net actuarial losses (gains)	**814**	594	**10**	(92)
Unamortized past service costs	**14**	18	**14**	18
Deferred pension asset (accrued benefit liability)	**424**	441	**(980)**	(948)
Less: current portion	**–**	–	**40**	40
Deferred pension asset (long-term liability)	**424**	441	**(940)**	(908)

[1] In January 2010, the Company made a contribution of $10 million in respect of 2009 (2009 – $10 million in respect of 2008).

[2] In August 2008, the Hydro One Pension Plan received $21 million in reciprocal transfers, of which $19 million represents a reciprocal transfer of assets from the Inergi Pension Plan.

		Pension	Employee Future Benefits Other Than Pension	
Year ended December 31 (Canadian dollars in millions)	**2009**	2008	**2009**	2008
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**52**	78	**19**	22
Interest cost	**286**	277	**63**	60
Actual return on plan asset net of expenses	**(631)**	1,113	**–**	–
Actuarial loss (gain)	**644**	(1,173)	**91**	(261)
Other	**(1)**	–	**–**	–
Costs arising in the period	**350**	295	**173**	(179)
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**359**	(1,465)	**–**	–
Actuarial (gain) loss	**(584)**	1,206	**(101)**	269
Plan amendments	**4**	4	**4**	4
Net periodic benefit cost	**129**	40	**76**	94
Charged to results of operations[3]	**68**	63	**50**	57
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**141**	108
Service cost and interest cost	**–**	–	**13**	14
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	–	**(113)**	(88)
Service cost and interest cost	**–**	–	**(10)**	(11)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**7.25%**	7.00%	**–**	–
Weighted average discount rate	**7.25%**	5.50%	**7.25%**	5.50%
Rate of compensation scale escalation (without merit)	**2.75%**	3.00%	**2.75%**	3.00%
Rate of cost of living increase	**2.00%**	2.25%	**2.00%**	2.25%
Average remaining service life of employees *(years)*	**10**	10	**11**	11
Rate of increase in health care cost trend[4]	**–**	–	**4.81%**	4.40%
For accrued benefit obligation, December 31:				
Weighted average discount rate	**6.50%**	7.25%	**6.50%**	7.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.75%	**2.50%**	2.75%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Rate of increase in health care cost trend[5]	**–**	–	**4.81%**	4.81%

[3] The Company follows the cash basis of accounting. During 2009, pension costs of $113 million (2008 – $103 million) were attributed to labour, of which $68 million (2008 – $63 million) was charged to operations and $45 million (2008 – $40 million) was capitalized as part of the cost of fixed assets.

[4] 8.81% in 2009 grading down to 4.81% per annum in and after 2029 (2008 – 8.33% in 2008 grading down to 4.40% per annum in and after 2018).

[5] 8.57% in 2010 grading down to 4.81% per annum in and after 2029 (2008 – 8.81% in 2009 grading down to 4.81% per annum in and after 2023).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2009**	2008
Environmental liabilities, January 1	**253**	65
Interest accretion	**13**	7
Expenditures	**(9)**	(14)
Revaluation adjustment	**70**	195
Environmental liabilities, December 31	**327**	253
Less: current portion	**(24)**	(16)
	303	237

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2009, and in total thereafter are as follows: 2010 – $24 million; 2011 – $34 million; 2012 – $34 million; 2013 – $42 million; 2014 – $37 million and thereafter – $218 million.

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands. The Company's liability is based on management's best estimate of the present value of the future expenditures expected to be required to comply with existing regulations.

There are uncertainties in estimating future environmental costs due to potential external events such as changing legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, for the PCB program, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on criteria including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except specified equipment, had to be disposed of by the end of 2009. However, in 2009, Hydro One sought and received an extension until 2014 for removal of certain station equipment that could be contaminated in excess of this threshold. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or more than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025. In addition, liquids with 2 ppm or more that have been removed from equipment cannot be reused.

Management judges that the Company has very limited PCB-contaminated assets in excess of 500 ppm. Priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets that must be compliant by 2014. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retrofilling with less than 2 ppm replacement oil.

Management's best estimate of the total estimated future expenditures to comply with PCB regulations is about $320 million. These expenditures will be incurred over the period from 2010 to 2025. As a result of its most recent cost estimate to comply with Environment Canada's PCB regulations and Environment Canada interpretations thereof, the Company has increased its December 31, 2009 environmental liability by approximately $30 million compared to September 30, 2009.

LAR
As a result of 2009 changes to provincial regulations governing land contamination mitigation and changes in acceptable regulated contamination thresholds, as well as other factors, the Company reviewed its liability for contaminated LAR. As a result of this review, the Company recorded a $40 million increase in its related liability, as compared to September 30, 2009. The Company's best estimate of the total future expenditures to complete its LAR program is about $69 million. As part of its review, the Company extended the term of its planned program for distribution properties from 2013 to 2020 and for transmission properties from 2015 to 2020.

Asbestos-Containing Materials
As a result of regulatory changes, Hydro One expects to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of its facilities. The Company plans to undertake additional studies, using the assistance of external experts as required, to estimate the incremental expenditures associated with removing such materials prior to facility demolition. This information will allow the Company to reasonably estimate and record any obligation it may have to incur such expenditures. The Company also anticipates that such future expenditures will be recoverable in future electricity rates.

14. SHARE CAPITAL

Common and Preferred Shares
On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends
Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2009, preferred dividends in the amount of $18 million (2008 – $18 million) and common dividends in the amount of $170 million (2008 – $241 million) were declared.

Earnings per Share
Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

15. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO, Ontario Power Authority (OPA) and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on UTRs approved by the OEB. Transmission revenue for 2009 includes $1,119 million (2008 – $1,072 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2009 includes $127 million (2008 – $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2009 includes $31 million (2008 – $21 million) related to these services.

In 2009, Hydro One purchased power in the amount of $2,296 million (2008 – $2,128 million) from the IESO administered electricity market, $19 million (2008 – $35 million) from OPG and $11 million (2008 – $18 million) from OEFC.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2009, Hydro One incurred $10 million (2008 – $9 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $13 million (2008 – $12 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $2 million (2008 – $1 million).

The OPA funds some of our Conservation Demand Management (CDM) programs. The funding includes program costs, incentives, management fees and bonuses. In 2009, Hydro One received $23 million from the OPA in respect of the CDM programs (2008 – $11 million) and had a net accounts receivable of $1 million (2008 – $6 million).

The provision for payments in lieu of corporate income taxes, property taxes and capital taxes was paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	**2009**	2008
Accounts receivable	**103**	103
Accounts payable and accrued charges	**(250)**	(260)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $211 million (2008 – $225 million).

16. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash" and "bank indebtedness." The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	**2009**	2008
Accounts receivable (increase) decrease	**(89)**	5
Materials and supplies (increase) decrease	**(2)**	4
Accounts payable and accrued charges increase	**-**	58
Accrued interest increase	**10**	9
Long-term accounts payable and other liabilities increase (decrease)	**4**	(1)
Employee future benefits other than pension increase	**32**	53
Other	**7**	(3)
	(38)	125

Supplementary information:

Interest paid	**361**	330
Payments in lieu of corporate income taxes	**77**	145

17. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band, which commenced on September 7, 2001, as all procedural issues in both matters were the same. There is now one action in which the claims of both the Whitesand First Nation Band and the Red Rock First Nation Band are set out. These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The claims arise out of flooding activities of Ontario Hydro and the alleged effects of flooding on lands in which the two First Nations claim an interest. By an agreement dated May 2009, all parties entered into an agreement to dismiss all of the actions against Hydro One without costs.

Transfer of Assets

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999, did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay annually more than the $822,000 that we paid to these Indian bands and bodies in 2009. If we cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

18. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Inergi LP (a wholly owned subsidiary of Cap Gemini Canada Inc.) began providing services to Hydro One. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. Inergi billing for these services has ranged between $93 million and $130 million per year and is subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002, the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2009, and in total thereafter are as follows: 2010 – $104 million; 2011 – $101 million; 2012 – $17 million; 2013 – $nil; 2014 – $nil and thereafter – $nil. The agreement expires on February 29, 2012.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2009 and December 31, 2008, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton using only parental guarantees of $325 million (2008 – $325 million). Prudential support at December 31, 2009, was also provided on behalf of two distributors using guarantees of $660 thousand (2008 – $nil). The IESO could draw on these guarantees if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the parental guarantee. If Hydro One's highest long-term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2009, Hydro One had bank letters of credit of $107 million (2008 – $107 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2009, and in total thereafter are as follows: 2010 – $9 million; 2011 – $5 million; 2012 – $7 million; 2013 – $6 million; 2014 – $6 million and thereafter – $26 million.

19. SEGMENT REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2009				
Segment profit				
Revenues	**1,147**	**3,534**	**63**	**4,744**
Purchased power	**–**	**2,326**	**–**	**2,326**
Operation, maintenance and administration	**438**	**564**	**55**	**1,057**
Depreciation and amortization	**240**	**287**	**10**	**537**
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	**469**	**357**	**(2)**	**824**
Financing charges				**308**
Income before provision for payments in lieu of corporate income taxes				**516**
Capital expenditures	**918**	**643**	**5**	**1,566**
2008				
Segment profit				
Revenues	1,212	3,334	51	4,597
Purchased power	–	2,181	–	2,181
Operation, maintenance and administration	387	531	47	965
Depreciation and amortization	254	287	7	548
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	571	335	(3)	903
Financing charges				292
Income before provision for payments in lieu of corporate income taxes				611
Capital expenditures	704	570	10	1,284

December 31 (Canadian dollars in millions)	2009	2008
Total assets		
Transmission	**9,118**	7,877
Distribution	**6,531**	5,873
Other	**161**	128
	15,810	13,878

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

20. SUBSEQUENT EVENTS

On January 22, 2010, Hydro One issued $500 million in notes under the Company's MTN Program. The issue was an additional offering of 3.13% notes maturing on November 19, 2014, originally issued on November 19, 2009. The total amount outstanding for this issue is now $750 million.

On January 22, 2010, Hydro One entered into two $250 million notional principal amount fixed-to-floating interest rate swaps to convert $500 million of Hydro One's 3.13% coupon note maturing November 19, 2014, into three-month variable rate debt.

On January 22, 2010, Hydro One purchased $250 million Province of Ontario Floating Rate Notes maturing on November 19, 2014 as a form of alternate liquidity to supplement its bank credit facilities.

On February 2, 2010, Hydro One entered into an additional $500 million committed revolving credit facility which supports its Commercial Paper Program and matures February 2013.

On February 3, 2010, Hydro One reduced its $1,000 million committed revolving credit facility maturing on August 20, 2010 by $250 million, to $750 million.

21. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2009 Consolidated Financial Statements.

Five-Year Summary of Financial and Operating Statistics

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	2007	2006	2005
Statement of operations data					
Revenues					
Transmission	**1,147**	1,212	1,242	1,245	1,310
Distribution	**3,534**	3,334	3,382	3,273	3,085
Other	**63**	51	31	27	21
	4,744	4,597	4,655	4,545	4,416
Costs					
Purchased power	**2,326**	2,181	2,240	2,221	2,131
Operation, maintenance and administration	**1,057**	965	995	880	792
Depreciation and amortization	**537**	548	521	515	487
	3,920	3,694	3,756	3,616	3,410
Regulatory recovery[1]	**–**	–	–	–	91
Income before financing charges and provision for payments in lieu of corporate income taxes	**824**	903	899	929	1,006
Financing charges	**308**	292	295	295	325
Income before provision for payments in lieu of corporate income taxes	**516**	611	604	634	681
Provision for payments in lieu of corporate income taxes	**46**	113	205	179	198
Net income	**470**	498	399	455	483
Basic and fully diluted earnings per common share *(Canadian dollars)*	**4,528**	4,797	3,809	4,366	4,652

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**9,118**	7,877	7,273	6,950	6,813
Distribution	**6,531**	5,873	5,407	5,161	4,893
Other	**161**	128	106	99	92
Total assets	**15,810**	13,878	12,786	12,210	11,798
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,655**	1,300	1,452	1,194	1,341
Long-term debt	**6,281**	5,733	5,063	4,848	4,443
Other long-term liabilities	**2,456**	1,721	1,385	1,347	1,298
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,791**	1,497	1,258	1,184	1,079
Accumulated other comprehensive income	**(10)**	(10)	(9)	–	–
Total liabilities and shareholder's equity	**15,810**	13,878	12,786	12,210	11,798

[1] As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004, the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

Five-Year Summary of Financial and Operating Statistics *(continued)*

Year ended December 31 (Canadian dollars in millions)	**2009**	2008	2007	2006	2005
Other financial data					
Capital expenditures					
Transmission	**918**	704	560	402	349
Distribution	**643**	570	511	417	338
Other	**5**	10	20	4	4
Total capital expenditures	**1,566**	1,284	1,091	823	691
Ratios					
Net asset coverage on long-term debt[2]	**1.79**	1.84	1.87	1.92	1.93
Earnings coverage ratio[3]	**2.15**	2.63	2.67	2.67	2.69
Operating statistics					
Transmission					
Units transmitted *(TWh)*[4]	**139.2**	148.7	152.2	151.1	157.0
Ontario 20-minute system peak demand *(MW)*[4]	**24,477**	24,231	25,809	27,056	26,219
Ontario 60-minute system peak demand *(MW)*[4]	**24,380**	24,195	25,737	27,005	26,160
Total transmission lines *(circuit kilometres)*	**28,924**	29,039	28,915	28,600	28,547
Distribution					
Units distributed to Hydro One customers *(TWh)*[4]	**28.9**	29.9	30.2	29.0	29.7
Units distributed through Hydro One lines *(TWh)*[4,5]	**43.5**	44.7	45.7	44.7	45.6
Total distribution lines *(circuit kilometres)*	**123,528**	123,260	122,933	122,460	122,118
Customers	**1,333,920**	1,325,745	1,311,714	1,293,396	1,273,768
Total regular employees	**5,427**	5,032	4,602	4,295	4,189

[2] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[4] System-related statistics include preliminary figures for December.

[5] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Board of Directors *(as at December 31, 2009)*

James Arnett[1,2,5]
Chair of the Board of Directors, Hydro One Inc.

Sami Bébawi[2,5,6]
Advisor to the President, SNC-Lavalin Group Inc.
President, Geracon Inc.

Kathryn A. Bouey[3,4,6]
President, TBG Strategic Services Inc.
Corporate Director

Laura Formusa
President and Chief Executive Officer, Hydro One Inc.

Don MacKinnon[5,6]
President, Power Workers' Union

Michael J. Mueller[1,2,4]
Corporate Director

Walter Murray[1,3,4]
Corporate Director

Robert L. Pace[1,3]
President and CEO, The Pace Group Ltd.

Gale Rubenstein[2,5]
Partner, Goodmans LLP

Douglas E. Speers[3,4,6]
Corporate Director

Board Committees

[1] *Audit and Finance Committee* The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met eight times in 2009.

[2] *Corporate Governance Committee* The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met seven times in 2009.

[3] *Human Resources and Public Policy Committee* The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on us. The committee met seven times in 2009.

[4] *Business Transformation Committee* The Business Transformation Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy and Smart Grid & Continuous Innovation Strategy. The committee met four times in 2009.

[5] *Regulatory and Environment Committee* The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures and reviews the Company's proposals for rate applications, compliance actions and reports. The committee met five times in 2009.

[6] *Health and Safety Committee* The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs and compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2009.

Concept and Design: **THE WORKS** www.worksdesign.com

Corporate Information

Corporate Address
483 Bay Street
Toronto, Ontario M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

Investor Relations
(416) 345-6867
investor.relations@HydroOne.com

Media Inquiries
(416) 345-6868
1-877-506-7584

Customer Inquiries
Power outage and emergency number:
1-800-434-1235

Residential, farm and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
KPMG LLP

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit **www.HydroOne.com**.