hydro One

We start every day with 100 years of experience

2005 Annual Report

1906–2005

Powering Ontario for 100 years.

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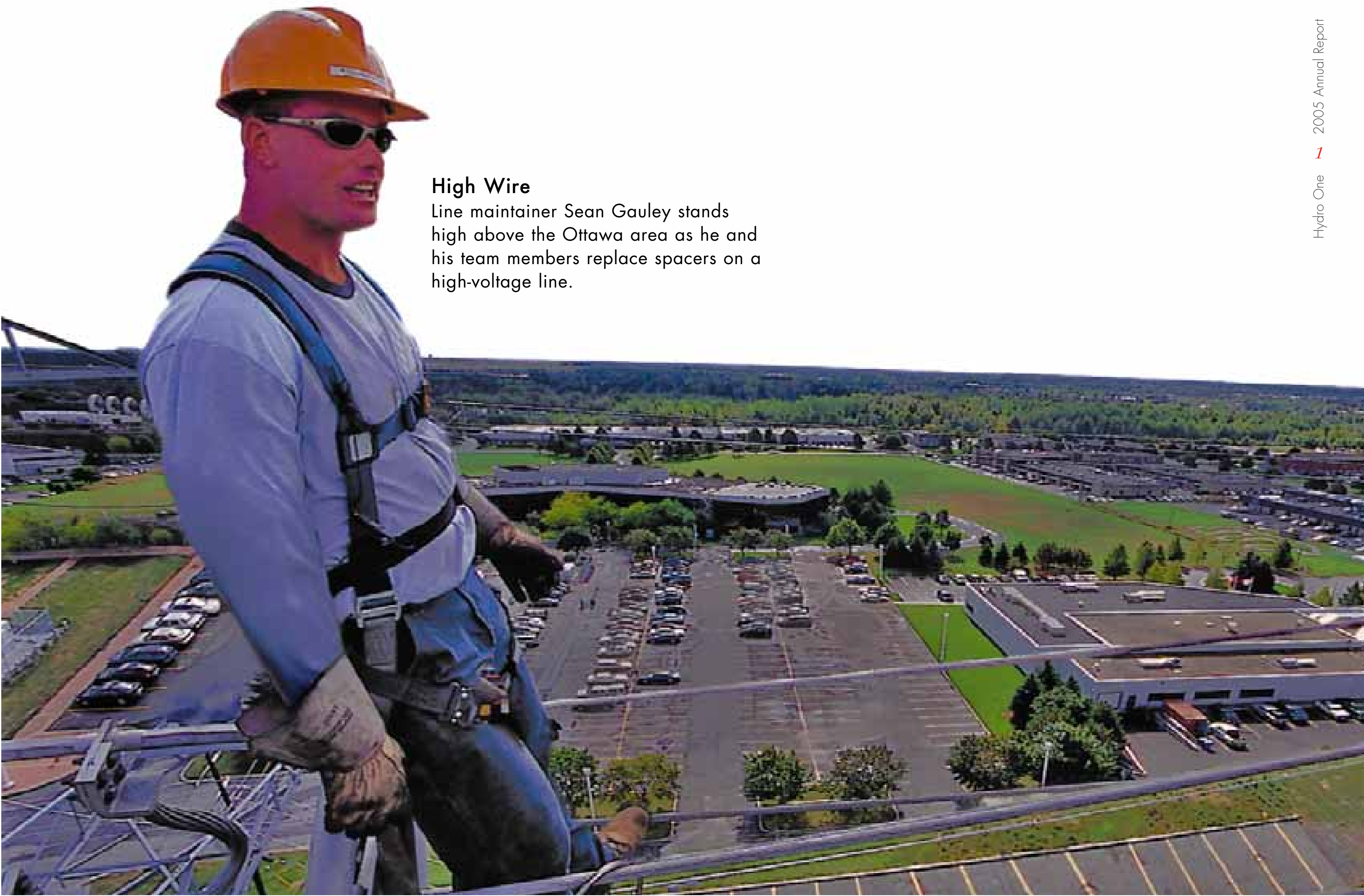
Standing Tall
Front Cover: Line maintainer Dan Butters does maintenance on a tower outside of London, Ontario.

Safety *Service* Reliability *Pride* Value

At the flick of a switch electricity arrives safely and reliably in your homes. It powers your businesses and helps you keep them growing. Our job is to take care of the system that enables electricity to flow to you, no matter where you live in Ontario. We work to make sure this vital resource is there when you need it. With your help, we're ensuring Ontario gets the most out of its electricity system.

We do this by focusing on our five values.



High Wire
Line maintainer Sean Gauley stands high above the Ottawa area as he and his team members replace spacers on a high-voltage line.

Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom. The subsidiaries are necessary to meet legislative and regulatory requirements.

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

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 18 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 and represents less than 1 per cent of our total assets.

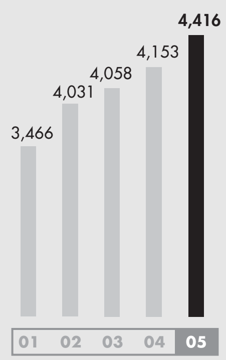
— Accomplishments in 2005 —

- Completed the Parkway transformer station on time and budget. This facility improves the reliability of the transmission system serving the electricity demand in the Greater Toronto Area (GTA) and helped facilitate the shut down of the Lakeview generating station.
- To better serve Canada's largest city, we began construction of two underground cable circuits to reinforce our electricity transmission facilities in downtown Toronto.
- To improve reliability and supply in southern Ontario, we started construction of a new 76-kilometre 230-kV line in the Niagara region.
- To secure necessary rates for future distribution work programs investments and system costs, Hydro One prepared and filed evidence with the Ontario Energy Board (OEB).
- Significantly improved or maintained customer satisfaction across all of our customer segments.
- Improved efficiency through an increasingly flexible workforce which is reflected in our strong financial results and our ability to achieve more for our customers and the people of Ontario.

— Key Credit Strengths —

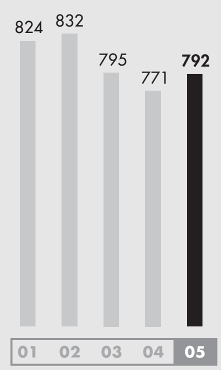
- Hydro One owns and operates the largest electricity delivery system in Ontario and one of the largest in North America
- Experienced management team focused on the core electricity delivery business
- Highly skilled and experienced workforce with first-class operating systems
- Recognized industry leader in the development and implementation of a safe workplace
- A track record of stable and predictable earnings from our regulated transmission and distribution businesses
- Conservative capital structure and strong cash flow performance

Year ended December 31 (Canadian dollars in millions)	2005	2004	$ Change	% Change
Revenues	**4,416**	4,153	**263**	**6**
Purchased power	**2,131**	1,987	**144**	**7**
Operating costs	**1,279**	1,251	**28**	**2**
Net income	**483**	407[1,2]	**76**[2]	**19**[2]
Net cash from operations	**1,170**	911	**259**	**28**
Statistics				
Transmission – units transmitted *(TWh)*[3]	**157.0**	153.4	**3.6**	**2**
Average Ontario 60-minute peak demand *(MW)*[3]	**23,074**	22,375	**699**	**3**
Distribution – units distributed to Hydro One customers *(TWh)*[3]	**29.7**	28.5	**1.2**	**4**



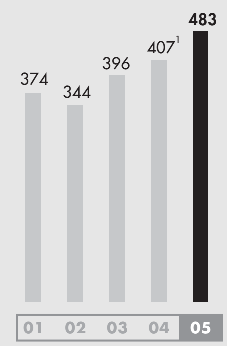
Revenues

Year ended December 31
(Cdn $ millions)



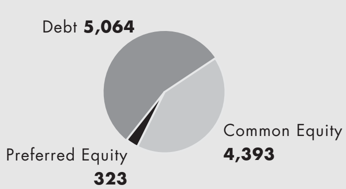
Operation, Maintenance and Administration Costs

Year ended December 31
(Cdn $ millions)



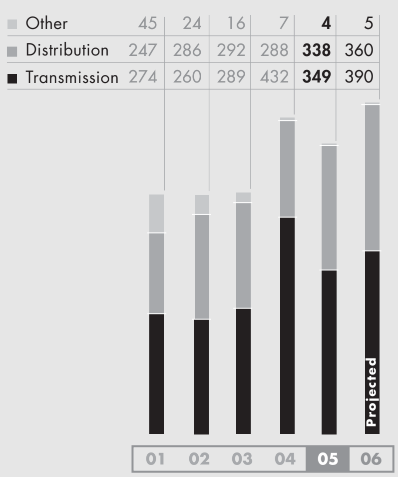
Net Income

Year ended December 31
(Cdn $ millions)



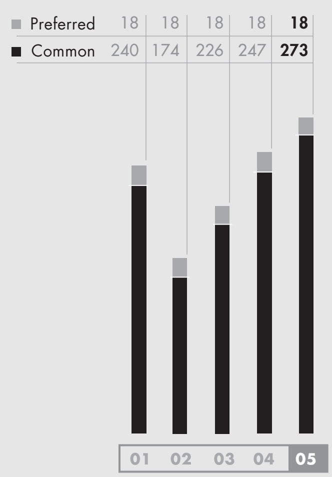
Capital Structure

December 31, 2005
(Cdn $ millions)



Capital Expenditure

Year ended December 31
(Cdn $ millions)



Dividends

Year ended December 31
(Cdn $ millions)

[1] Net income for 2004 was $498 million, including a one-time regulatory recovery of $91 million.

[2] Based on 2004 net income of $498 million, which includes a one-time regulatory recovery of $91 million, 2005 net income was lower by $15 million, or 3%.

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

The Company's excellent results reflect Hydro One's continued commitment to transparent, prudent management of this vital provincial asset.

In 2005, Hydro One successfully operated and maintained Ontario's transmission and largest distribution system, skillfully navigating the operational challenges posed by one of the hottest summers on record that set new record peaks for demand. Hydro One's previous investments in its system paid off and the Company embarked on several large projects to ensure reliable supply for the people of Ontario.

In 2005, Hydro One continued its track record of strong financial performance. The Company's net income in 2005 increased $76 million, or 19%, to $483 million compared to 2004, putting aside the impact of last year's one-time regulatory recovery. This increase primarily reflects higher revenues within our transmission and distribution businesses, including the impact of the summer's record heat. During the heat wave, Hydro One maintained an intense focus on its operations over the summer months to ensure the reliable delivery of electricity across the province.

As Chair of Hydro One, it's my role to ensure that the Company operates in a transparent, accountable and responsible way. Hydro One conforms to the highest standards of corporate governance in our relationship with our shareholder and in the fulfillment of our fiduciary responsibilities as a Board. The Board of Directors in 2005 was highly engaged, ensuring Hydro One remains focused on maintaining a strong, fiscally responsible and reliable electricity system that meets today's needs and is prepared for the challenges that lay ahead. This year, Hydro One focused on new securities regulations and is well positioned to meet these new requirements set out by the Ontario Securities Commission.

The Company's excellent results reflect Hydro One's ongoing commitment to the transparent, strong and focused leadership of our CEO, Tom Parkinson and our ongoing commitment to prudent management of this vital provincial asset. Hydro One made critical investments both in transmission and distribution infrastructure as well as in maintenance programs designed to ensure the reliability of the system. Total capital and operation, maintenance and administrative expenditures for 2005 were $1,483 million. In addition, Hydro One paid its shareholder, the Province of Ontario, dividends of $291 million, and recorded $198 million of payments in lieu of income taxes, which helps reduce the legacy-stranded debt held by the Province. The Board expects continued strong, stable financial performance.

I would like to take this opportunity to express my thanks to the Board members for their contribution and dedication. I would also like to especially thank retiring Board members Geoffrey Beattie, Adam Zimmerman and Dr. Murray Frum. As directors, each of them made outstanding contributions to the continued success of Hydro One.

On behalf of the Board of Directors, I would like to thank all of Hydro One's people for their valued contribution and their dedication to their vital role. The Board looks forward to continuing the work of Hydro One in providing a safe, reliable electricity delivery system for the people of Ontario.

Rita Burak
Chair, Hydro One Inc.

Our goal is to be the best transmission and distribution business in North America.

We start every day with 100 years of experience.

I look at the black and white photographs on the walls of our boardroom and I see a proud history. Using draught horses, steam power and raw force of will, the people of Hydro Electric Power Commission (H.E.P.C.) connected the power of Niagara Falls to Ontario communities. Those first transmission lines brought more than electricity. They brought prosperity. They brought a higher standard of living. They brought a better future. The power delivery system that gradually spread to connect almost every community in Ontario meant that Ontario businesses, communities and families have prospered and grown in the last century. Today we continue that work. We deliver the electricity that is the very lifeblood of Ontario's economy.

In 2005, we worked hard to integrate new sources of generation into the system. We've begun construction of our Niagara Reinforcement Project to upgrade the transmission line that delivers the power produced in Niagara Falls to the rest of Southern Ontario. By upgrading this line, we will be able to deliver an additional 800 MW of electricity to where it needs to be. The new Parkway transformer station in the GTA was completed on time and on budget, safely facilitating the decommissioning of the coal-fired Lakeview generating station. Work has also begun on an underground cable in downtown Toronto to improve supply flexibility to Canada's largest city.

In 2005, Hydro One faced one of the hottest summers on record. With 45 days with temperatures above 30 degrees, the aging transmission system was stretched to its very capacity. But it held. It held because we've invested wisely in our systems over the years. It held because our team knows how to get the very most out of Ontario's electricity highway. While I'm proud that our system and our people were able to meet the challenges of the summer, I also believe that as demand increases we need to find better ways of doing things. Part of the answer will be found in working with our customers to find conservation solutions that work. In 2005, we had some success with conservation pilot projects and in 2006 we are looking to achieve more.

2005 was a dynamic year for our company. Hydro One earned a profit of $483 million and we paid our shareholder, the Province of Ontario an excellent dividend. We remain committed to earning a healthy return for our shareholder while ensuring Ontario's electricity delivery

system can continue to perform at an optimal level long into the future. Our stable and strong financial results this year were consistent with our expectations.

By 2010, our goal is to be the best transmission and distribution business in North America. What does this mean? We want to have the best safety record in the world, with zero serious injuries and zero serious near misses. We have top quartile reliability in transmission and are working towards the same in distribution when compared against similar utilities. Customer satisfaction, where major gains have been made in the last two years, is targeted to reach 90 per cent across all segments. We will continue to deliver shareholder value through fair transmision and distribution rates, prudent expenditures, employee productivity improvements and excellent operating efficiency.

Stable and strong are not euphemisms for static or stationary. The electricity industry, after 100 years of rich history in Ontario, is possibly at one of its most critical junctures. New transmission facilities are needed to facilitate the delivery of new supply to customers, to reduce constraints on the system, and improve our ability to import electricity. Only by improving cooperation and coordination between communities, regulators and industry partners can we continue to reliably deliver the electricity that Ontario depends upon. Only by realizing that we are all working towards the same goal – safe reliable electricity and continued prosperity for Ontarians – can we move quickly enough to put the necessary and proper assets in place.

I'd like to thank the people of Hydro One for their commitment to our strategic direction, and for the fantastic job they do everyday. It shows in our results and in the satisfaction of our customers. Much has changed in the last century. We do things differently, we use different tools and we work much more safely. But one thing has not changed. We continue to focus on providing the people of Ontario with an electricity delivery system that allows them to prosper now and long into the future.

Tom Parkinson
President and Chief Executive Officer, Hydro One Inc.

Connecting Ontario
Left: Stringing the first transmission lines on steel towers to connect the Niagara area to southern Ontario communities. February, 1910.

Broad Shoulders
Above: Hydro One's high-voltage system includes more than 28,000 circuit kilometres of lines supported by nearly 48,000 towers all over Ontario. In 2005, work was started to upgrade 76 km of line to allow more electricity to flow from the Niagara region.

"We are off now, just let anyone try and stop us."

With that sentence, Sir Adam Beck opened the Wasdell Falls generating station. Beck, also known as the father of Ontario's electricity system, had a vision that electricity was the way to a bright future for everyone in Ontario. He pushed for the construction of generating stations to produce electricity on a massive scale.

But it wasn't enough to just produce power. Beck believed that only by delivering power to all parts of Ontario would everyone share in the economic prosperity that electricity brings.

He oversaw the development of a network of transmission and distribution lines that has now grown to stretch more than 150,000 kilometres across all parts of Ontario.

His vision and energy helped make Ontario the economic engine of Canada. Without electricity, our world would be a very different place. Hydro One continues to focus on delivering electricity and economic prosperity to the people of Ontario.

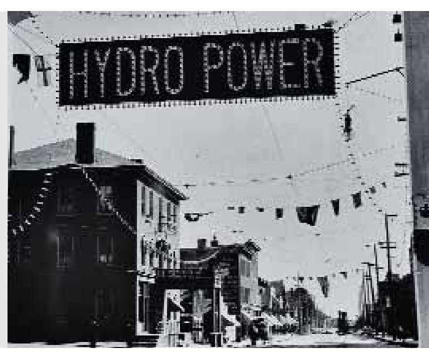
1906
The Hydro-Electric Power Commission is created to build transmission lines to carry power generated at Niagara Falls. Adam Beck, is named chairman.

1910
The first 110,000-volt electric power lines deliver electricity to municipalities in southwestern Ontario, starting with Kitchener (then known as Berlin).

1912
The Beck Electric Circus tours the countryside showcasing the wonders of electricity.

Left: From the very early days, London was at the forefront in promoting hydro, as demonstrated by this photograph taken on the occasion of the Labour Parade in that city on September 1, 1913.

Right: This is a close-up of one of the displays that formed part of the colourful decorations in Kitchener on October 11, 1910, marking the first time power was switched on in that community.



1922
What would come to be known as the Sir Adam Beck 1 generation site on the Niagara River goes into service. At completion it's the largest generation facility in the world, requiring five times the excavation of the largest of the Great Pyramids.

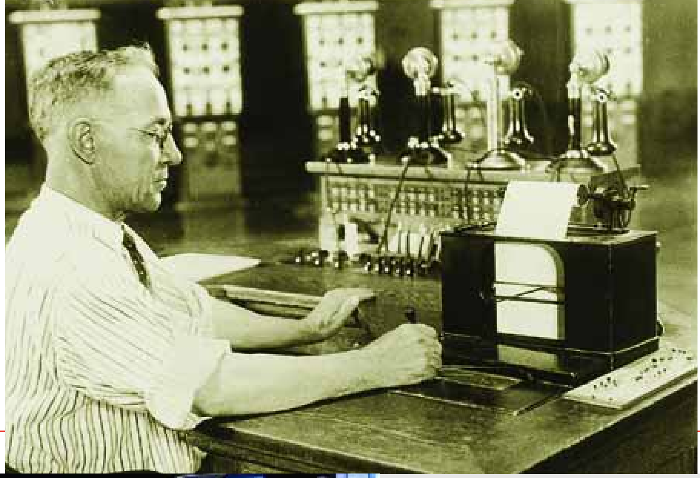
Wiring Ontario for Delivery
Right: Workers at an early distribution station ready the wiring for commissioning. In the early days of building Ontario's electricity system, building and commissioning equipment was a major part of Ontario Hydro's work.

Making Connections
Below right: Leaside transformer station in Toronto is a major hub in our electricity delivery system. Transformer stations not only convert high-voltage electricity to lower voltages, they also expedite the delivery of electricity between stations.

building reliability

In the first 70 years of its existence, Ontario's electricity company focused as much on new construction to keep up with growing demand as it did on the actual business of generating and delivering electricity.

While we're solidly focused on operating and maintaining our transmission and distribution assets, we are now entering a phase that will bring much more new construction. In 2005, Hydro One invested more than $700 million in upgrades, construction and maintenance for our transmission network. With the lengthy approval process for new construction, we are often working with our customers and industry partners to plan our work schedule years in advance.



Power People
Left and above: Highly skilled professionals, like Cathy Freskiw, are at the heart of Hydro One's system. Even though the equipment has changed a great deal, our commitment to delivering a reliable supply of electricity to the people of Ontario has not.

Taking Care of Distribution

In 2005, we increased our capital investments in our distribution system by $50 million over 2004, from $288 million to $338 million.

This includes investment in new mechanical brushing equipment that will greatly enhance our ability to keep our distribution rights-of-way clear. Better brushing techniques will translate directly into improved service and productivity by decreasing the number of outages and allowing our crews easier access to remote equipment.

Pole replacement projects targeting communities across the province, from Kemptville to Moosonee, replaced 3,600 poles nearing the end of their service life. This work will continue in 2006 and beyond to ensure ongoing reliable supply to our approximately 1.3 million Hydro One distribution customers.

Niagara *Reinforcement* Project

In 1910, the power of Niagara Falls was first connected to Ontario's electricity consumers along the province's first transmission lines. Those first lines delivered more than electricity. They delivered a new way of living, working and doing business. They changed our world.

This year, we began a major upgrade of transmission facilities so that even more of the Falls' awesome power can reach Ontario's homes and businesses by the summer of 2006. Engineering and construction crews are taking down an old 115 kV line and replacing it with a new 230 kV double-circuit line across 76 kilometres. This project will allow us to deliver 800 MW more power – enough for 300,000 homes – from the Niagara Falls area to where it needs to be.

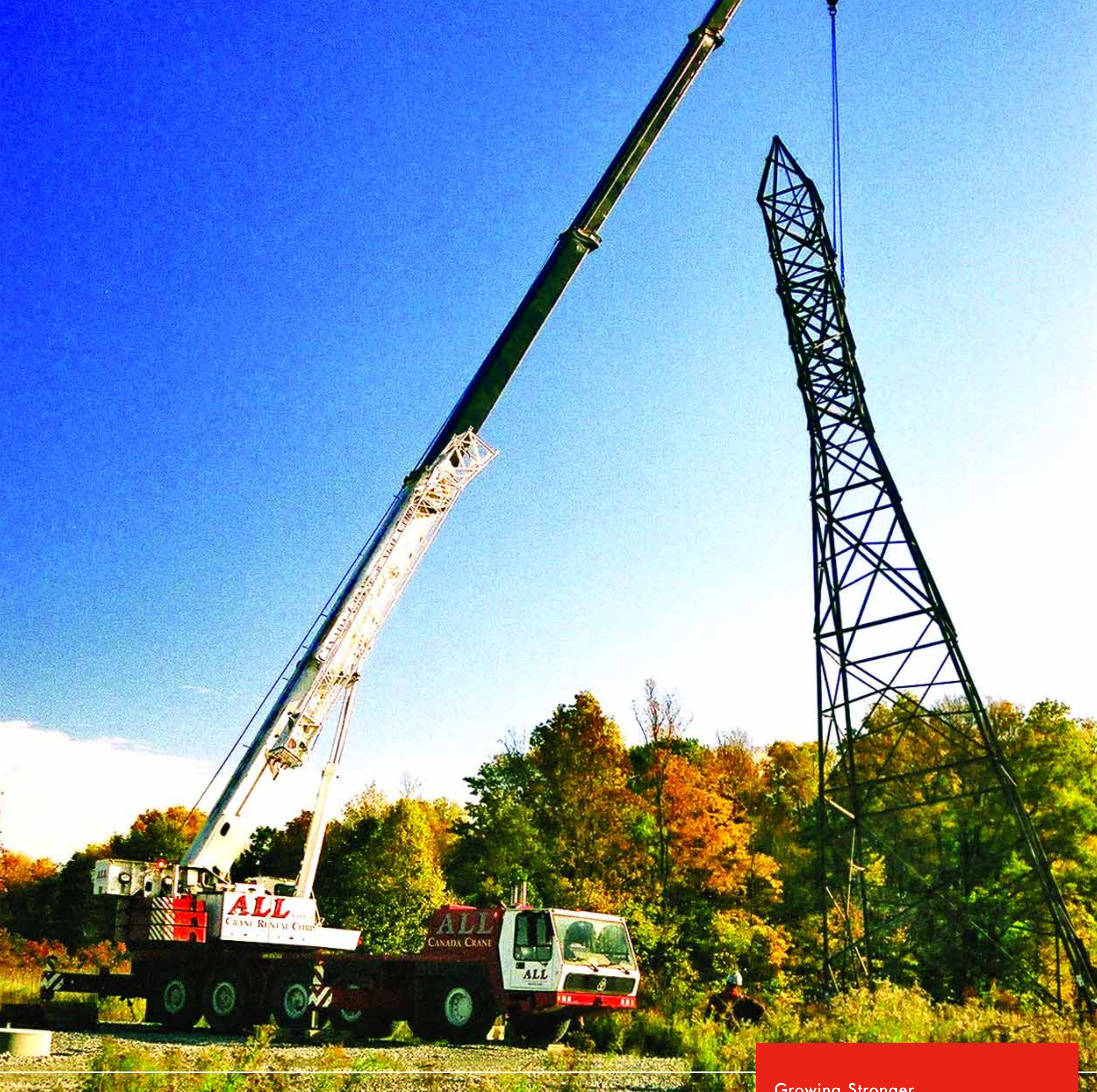
This project will also make new generation development possible in the Niagara Falls area, reduce the risk of supply shortages, allow for more efficient use of existing generation resources and reduce transmission line losses. It also improves Ontario's ability to import power from New York State when we need it. The start of construction in 2005 followed years of hard work on planning and approvals by employees across the Company. It has been included in our 10-year plan for several years. With the urgent need and the tight timeline, teams are working closely together to make sure the project stays on target. We are confident it will be delivered on time and on budget.

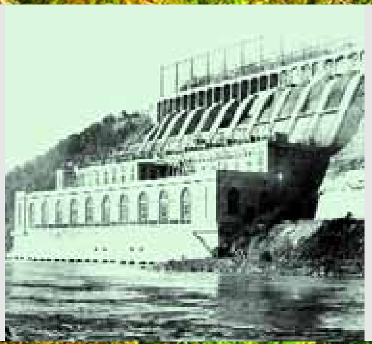
1930s
The Great Depression slows the demand for electricity.

1939
WAR! Ontario powers up to produce enough electricity to meet wartime production needs. Links with Quebec are established.

Left: Ontario Hydro linemen up the pole on June 11, 1947, were using hot line tools to work on "live" lines.

Left: Using single-horse power, these men made good progress in laying cable near Beamsville, Ontario, on November 22, 1923.





Left: The power of Ontario's waterways was the major source of electricity in the first half of the 20th Century.

Growing Stronger

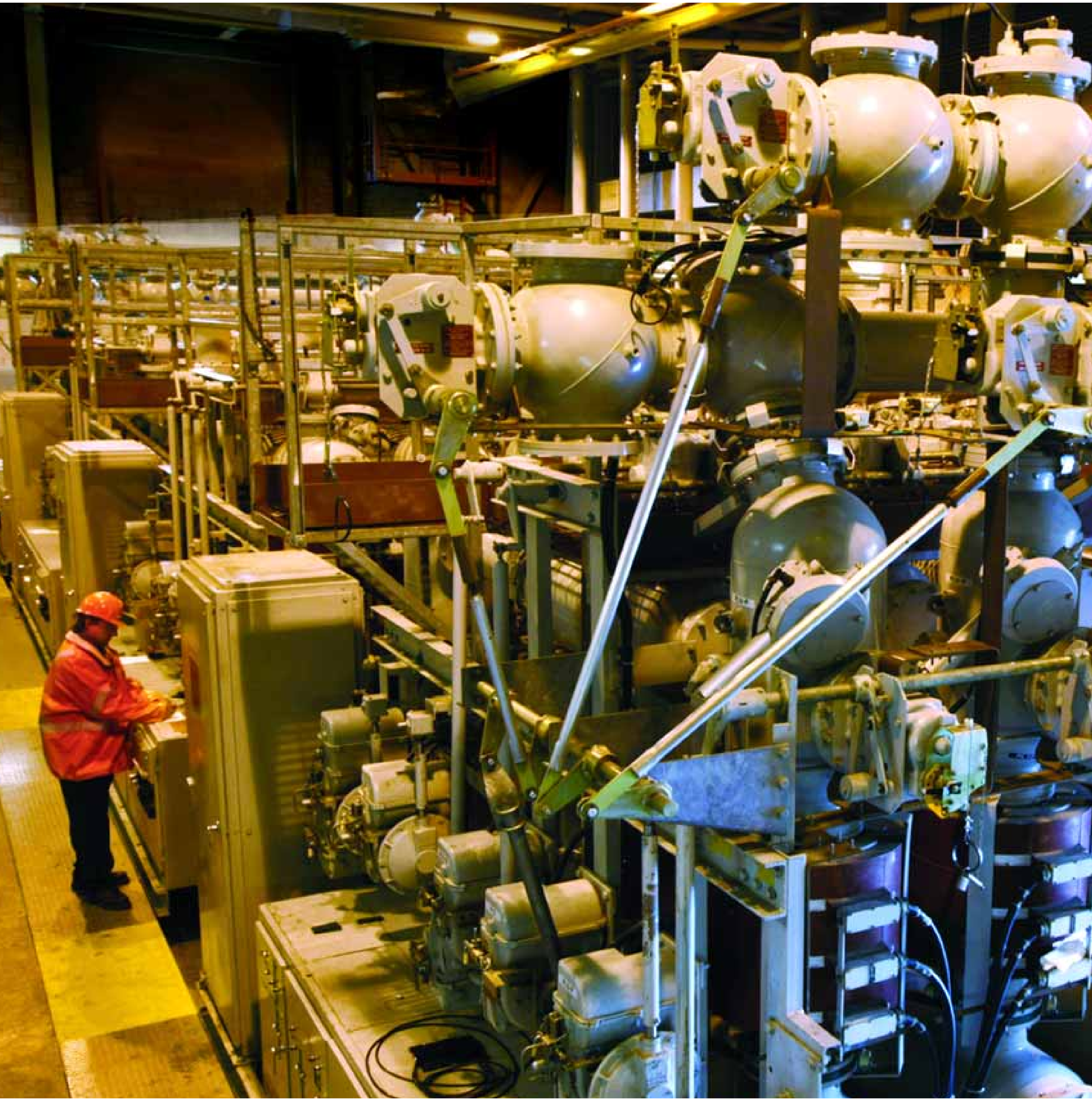
Above: Upgrading our system, like our Niagara Reinforcement project, is part of our core strategy for the years ahead. The Niagara project is expected to be completed by the summer of 2006 and will bolster our ability to deliver power from the Niagara region to southern Ontario.

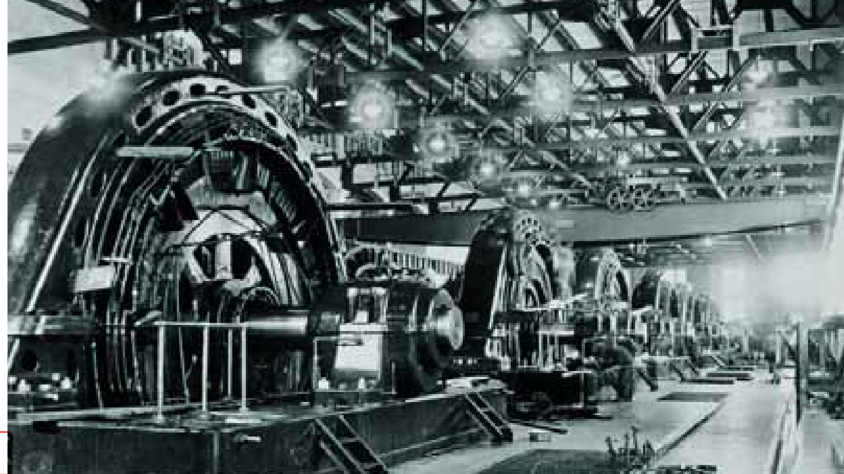
1941

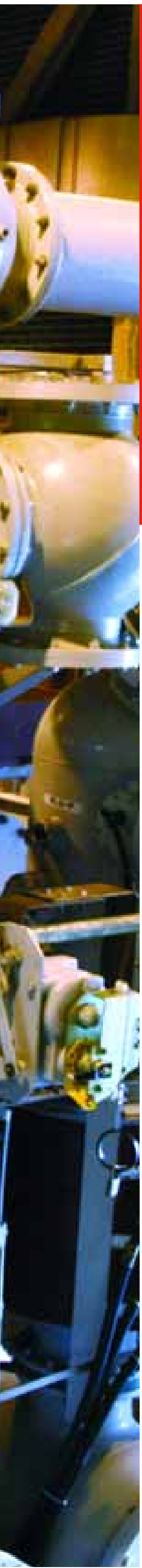
As part of the war effort, the first conservation program is started and customers are urged to "Save Hydro in Your Home: Help Win the War!"

1949 to mid 1950s

Power stations and transmission systems are centralized into one network for efficiency and flexibility. Ontario becomes compatible with the frequency of neighbouring provinces and states.







Vital Hub
Left: John Wright inspects equipment at the Cecil transformer station, a vital part of Hydro One's delivery system to downtown Toronto. Discreetly enclosed inside of a brick building, most people walking by wouldn't even notice the facility.

Feeding the System
Above: Water-powered generation plants like this one have been providing Ontarians with clean sources of electricity for more than a century.

Parkway transformer station

Parkway transformer station came into service in 2005, significantly strengthening the system supplying power to the GTA. It is part of our efforts to ensure power supply reliability to the GTA and to accommodate future growth. It strengthens the transmission system and supported the shutdown of the Lakeview generating station. The design, construction and start-up of this project on time and on budget is a tribute to the excellence of our employees.

Esplanade Cable Project

On March 11, 2005, the OEB approved our application to reinforce our electricity transmission facilities in downtown Toronto by constructing two new underground cable circuits between the John and Esplanade transformer stations. This project will reinforce existing infrastructure and allow us to deliver electricity to Toronto through a more flexible system. We began work in the fall, boring the tunnel beneath Toronto's subway system 30 metres underground connecting the two transformer stations, which are about 10 city blocks apart. We expect to have the cable in service in 2007.

forestry

Hydro One's lines traverse Ontario's roughest terrain. With 640,000 square kilometres of service territory we invest considerable time and effort to keep our lines clear of brush and trees. Downed trees and falling branches are a major cause of outages and keeping our lines clear improves reliability during stormy weather. In 2005, our forestry crews cleared 11,863 hectares of brush along our transmission corridors and 3,216 km of trees along transmission lines. We also cleared 9,076 km of our distribution lines.

In 2005 we moved further towards our target of returning our provincial clearing cycle on to a well-defined, seven-year clearing cycle for transmission lines and an eight-year clearing cycle for distribution lines. Carrying out our forestry program efficiently and consistently means fewer power outages caused by trees down on the lines.

Above: Forestry apprentices Jason Swant (front) and Frank Graves train in Cloyne, Ontario, to use Hydro One's advanced rigging system.

1950s
Hydro workers go door-to-door replacing more than 7 million appliance motors to match the new frequency.

1954–1958
The 1328-megawatt Sir Adam Beck 2 plant is built on the Niagara Gorge adjoining Sir Adam Beck 1.

1958
The 912-megawatt R.H. Saunders plant in Cornwall, Ontario is declared in service by Queen Elizabeth and American Vice-President Richard Nixon.

Left: This motor sled was used by a maintenance crew in the North Country in April 1942.

Left: Taken in 1943, this photo shows the transformer at the rear of the municipal office at Paris and a Hydro service truck.

Left: Before Ontario Hydro foresters could quickly rise to great heights in hydraulically operated buckets, they could rise to most occasions with the safety–tested equipment shown in this June 1947 photo.

Treetop Trimmers

Above: Hydro One foresters are highly trained to work on trees near live lines. Trimming and removing trees and brush helps prevent the inconvenience of power outages for our customers. Since 1999, we've reduced the number of outages by 10 per cent, largely through preventative measures like our forestry program.

1960
Construction of Canada's first 500,000–volt transmission line begins, connecting supply between northern Ontario and southern Ontario.

High Life
Left: Working on both our distribution and transmission system requires years of training and expertise.

working *safely*

In the last century, a quantum leap has been made in workplace safety. Early work on Ontario's electricity system exacted a significant human cost. From 1918 to 1928, the first decade of record keeping, 244 workers lost their lives building generating stations, stringing power lines and erecting towers. In the last decade, four workers died on the job working for Ontario Hydro's successor companies. Much of the credit for this dramatic improvement can be directly linked to the innovative ideas of the bright and dedicated employees of our company's predecessor. Today, the men and women of Hydro One proudly carry on that tradition. In recent years, we have introduced better work procedures, improved fall arrest equipment and techniques, arc-resistant clothing and advanced rigging techniques and improved design/equipment standards, to name a few.

While the evolution of safety is moving in the right direction, to Hydro One, zero is the only acceptable number. And we did not achieve it this year. On April 9, 2005, a Hydro One electrician was killed while working at our Cooksville transformer station. His loss is deeply felt and our sympathy goes out to his family.

While much has changed over the last 100 years, our primary hazards haven't. We work around and with electricity. We often work high above the ground. Annually, we log millions of kilometres driving on Ontario's highways and back roads, often in the worst weather conditions.

Front cover & page 20: Dan Butters

Left: This lineman was twisting absorber rods on cables when this picture was taken on January 18, 1932.

Airborne Line Maintainers

Left: Working on towers that are sometimes more than 200-feet tall either requires long hours of climbing or the expertise to step down from our AirStair device. The AirStair allows our helicopter to safely drop off and pick up line maintainers on top of our structures and was developed by Hydro One employees.

Know the Job

Right: From Left–Derrick Bridges, Mike Reid, John Bosomworth and Scott Punsit break down the job ahead. Before any work starts, each member of the team is briefed on the entire job and understands their role, the hazards and the role of everyone on the team.

On the Road

Left: Our crews spend countless hours driving and working alongside Ontario's roads. Driving and road safety training are a mandatory part of being on our team.

Our focus remains on achieving zero injuries caused by electrical incidents, falls and falling objects and those resulting from the operation of vehicles and equipment. Although we did not achieve our aspirational safety targets for 2005, we are closing the gap. The number of serious incidents was 12 per cent lower than 2004 and 28 per cent lower than 2003. Since 1999 our lost-time accident frequency rate has dropped by about half, putting us in the top quartile of Canadian transmission and distribution companies.

We continue to change our safety culture and infuse safety into every project and every decision, every day. From head office to the field, from Ottawa to Pigeon Lake, safety is our top priority and the entire company is committed to this goal.

In Towers We Trust

Above: Line maintainers see our beautiful province from a perch like this one on a tower in the London area. Maintaining the transmission system requires inspection with thermal reading equipment from trucks and helicopters and then repairing weak spots in the system.

Left: Stringing of transmission line on steel towers in the Niagara area is shown in this photo, dated February, 1910.

a workforce that *delivers*

By 2008, about a quarter of our workforce will be eligible for retirement. We are preparing for turnover in our workforce by actively identifying successors inside the company and drawing in new talent from outside. We are promoting careers in skilled trades and our recruitment efforts of university graduates are highly successful.

Hydro One is working with the Power Workers Union and our industry partners to recruit apprentices in lines and forestry so a skilled workforce is always there to take care of our system. We're also supporting co-op engineering programs at the University of Waterloo and other post-secondary institutions in Ontario.

Hydro One's labour relations strategy focuses on protecting shareholder value and providing for future economic stability for the Company. In 2005, we ratified collective agreements with four different unions. We were unable to reach an agreement with The Society of Energy Professionals, resulting in a 15-week strike that ended with an arbitrated settlement. In the arbitration award, the company achieved two-tier pensions, one of its key bargaining objectives. The less provident pension plan applies to future hires into Society-represented positions and translates into a 25 per cent cost-savings compared with the existing pension plan. This is in line with the reduced pension plan instituted for management employees hired after January 1, 2004.

We remain focused on increasing operational flexibility and decreasing labour costs so we can continue to deliver electricity to Ontarians at a fair price.

1970
One synchronized, province-wide grid is created, with the exception of remote communities.

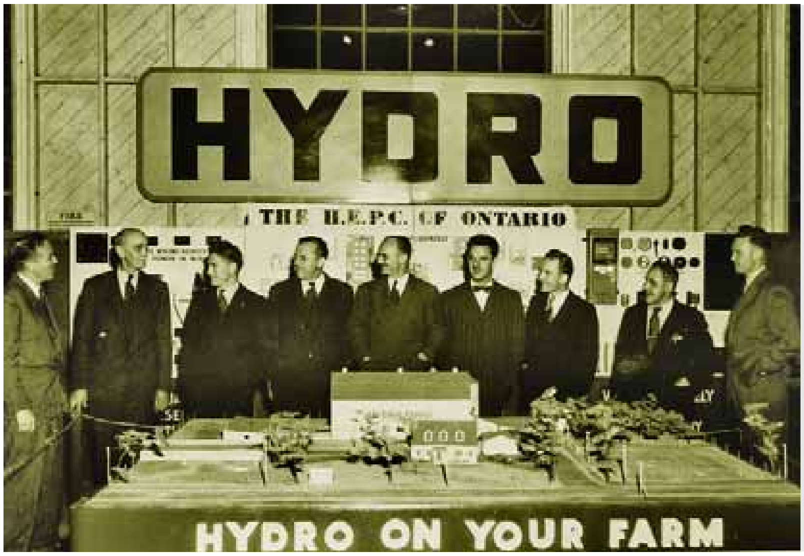
1971
Pickering nuclear generating station delivers nuclear powered electricity to Ontarians for the first time.

1977
The Bruce nuclear generating station comes into service.

Left: At the C.N.E. in 1936, Ontario Hydro "played up" the theme of "Better Light Better Sight."

Left: December 7, 1921. An early method of spooling out cable.

1989
The first unit of the Darlington nuclear generating station comes into service.



Left: Ontario Hydro's rural exhibit at the 1946 International Plowing Match at Port Albert.

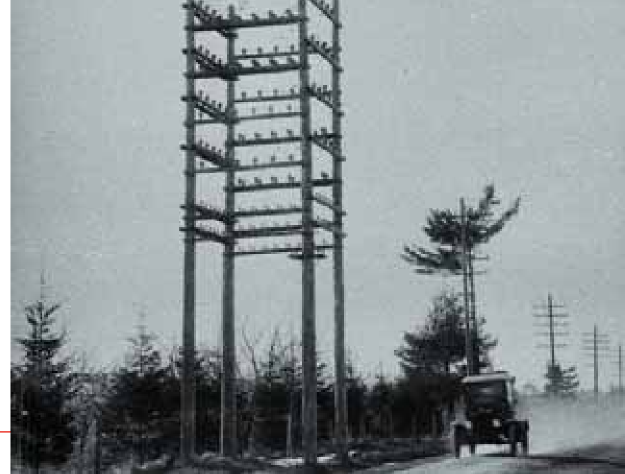
community and *conservation*

In the 1940s, Ontario Hydro asked Ontarians to conserve electricity to help with the war effort. In 2005, with demand almost outstripping supply and the system running at maximum capacity at peak hours, we're once again encouraging our customers to use electricity wisely.

With the cost of electricity rising, conservation has never been more important. Hydro One introduced several programs in 2005 to help Ontario communities cope with rising costs of electricity and reduce usage.

Low-income energy efficiency grant

Hydro One has teamed up with Canada Mortgage and Housing Corporation and Natural Resources Canada to provide financial incentives for energy-efficiency upgrades to low-income Hydro One customers who heat their homes with electricity. This is the first initiative of its kind in Canada, where three different organizations have come together to provide substantial benefits to homeowners who might not otherwise be able to afford upgrades. Under the Home Energy Efficiency Grant initiative, Hydro One is offering up to $3,000 per qualifying household.



Left: Community education at fairs and in schools is a vital part of Hydro One's corporate sponsorship program. We've dedicated $20,000 in each of three years towards energy and electricity workshops through Scientists in Schools and we've also committed to $150,000 over three years to expand the Advanced Coronary Treatment CPR programs in schools.

Below: Hydro One supports employees who volunteer with youth sports teams by providing sponsorship grants that make it easier for kids to get outside and play.

Above: Taken at Cooksville in March 1918, this photo shows what was known as a right angle structure.

knowledge is *using less power*

Hydro One's engineers had a question. If people know how much electricity is costing them on a real-time basis, does it affect the way they use this valuable commodity? To answer this question, our staff conducted a year-long real-time monitoring pilot-program. One of the largest studies of its kind undertaken in Canada, 500 of our residential customers volunteered to have their meters fitted with sensors that captured real-time electricity usage and transmitted it to a small screen in the house. The screen showed exactly how much electricity was being used that month and what it was going to cost the family. They could see the projected monthly amount go lower when they turned off the air conditioner. They could see it go up when they switched on every appliance in the house. By knowing the dollars and cents of their daily usage, our customers used less. Compared to the previous year, the pilot program families reduced their usage between 7 and 10%. Sometimes, knowledge means using less power.

Holiday LED exchange

Hydro One delivered holiday cheer in the form of energy savings to communities across Ontario by exchanging a new string of energy efficient Light Emitting Diode (LED) lights for two strings of old holiday lights. Using LEDs instead of traditional incandescent bulbs adds up to big energy savings over the holiday season. Compared to traditional lights, LEDs use up to 95% less energy, last at least 7 times longer, are more durable, with no filaments or glass bulbs to break and produce very little heat, reducing the risk of fire. Safe, smart and good value; now that's a great idea.

1997
We launch our first Web site, now called HydroOne.com.

1998
Heroic hydro workers toil in icy, freezing conditions to replace 10,750 poles, 1,800 transformers and 2,800 km of power lines destroyed by the Ice Storm.

1998
Ontario Hydro is broken up into five companies: Ontario Power Generation, Ontario Hydro Services Company, the IMO, OEFC and the ESA.

Left: Ontarians took great pride in the electricity delivery system in the 1950s and public tours of then "futuristic" control rooms were often in high demand.

Left: When the first nuclear plants were planned, Ontario Hydro spent a great deal of time on public information and education. When Hydro One embarks on a major project, community consultation is an important part of the plan.

Delivering Quality of Life

Left and above: Hydro One serves approximately 1.3 million distribution customers across Ontario. The electricity we deliver powers businesses, communities and families.

2000
Ontario Hydro Services Company is renamed Hydro One Inc.

2000 – 2002
Under a new legislative framework, Hydro One acquires 89 local distribution companies, increasing its customer base by 25 per cent to 1.2 million.

2002
Hydro One's Charity Trust program raises $650,000 for Ontario charities.

2003
A tree on a transmission line in Ohio causes a power outage that affects the entire Eastern Seaboard of North America. Hydro One crews worked rapidly to be able to deliver all available power within 24 hours.

Founding Father of Power in Ontario

Sir Adam Beck was a prosperous London, Ontario, manufacturer, who was simultaneously the Mayor of London and a member of the provincial legislature. Beck was an early champion of public power and lobbied hard to have the hydro-electric power resources at Niagara connected to communities across Ontario. In 1906, Beck became "Power Minister" and chairman of the Hydro-Electric Power Commission of Ontario, the world's first publicly-owned utility.

His initial project was to build a 110,000-volt transmission line from Niagara Falls to carry power to southwestern Ontario municipalities, including Toronto and 13 other communities. On October 11, 1910, Beck held his first ceremonial "switch-on" in Berlin (now Kitchener) to celebrate the completion of this line. When he pressed a switch and lit a street sign that read "For the People", the town went wild.

Before he died in 1925, Beck was instrumental in developing the 450-megawatt Queenston Chippawa power station at Niagara Falls. When it was commissioned, it was the largest power station in the world. In 1950, this station was renamed Sir Adam Beck I to honour his memory.

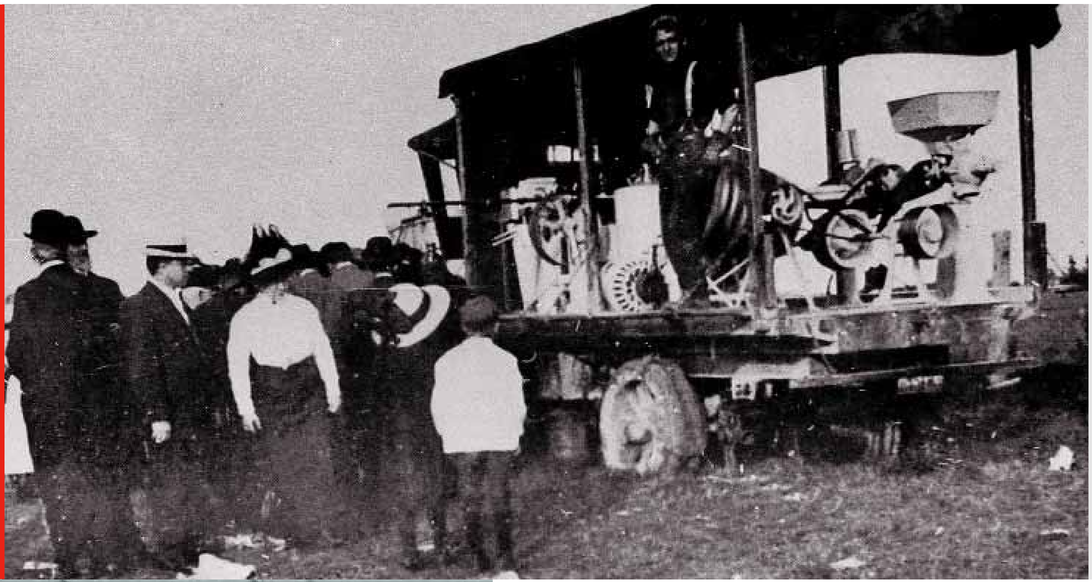
Above: Two units of the Adam Beck "Circus," which carried various appliances to the farms of Ontario to provide on-the-spot demonstrations, can be seen in the background of this photo taken in 1912. When they saw how easy it was to saw wood with Hydro, fewer and fewer farmers had axes to grind.

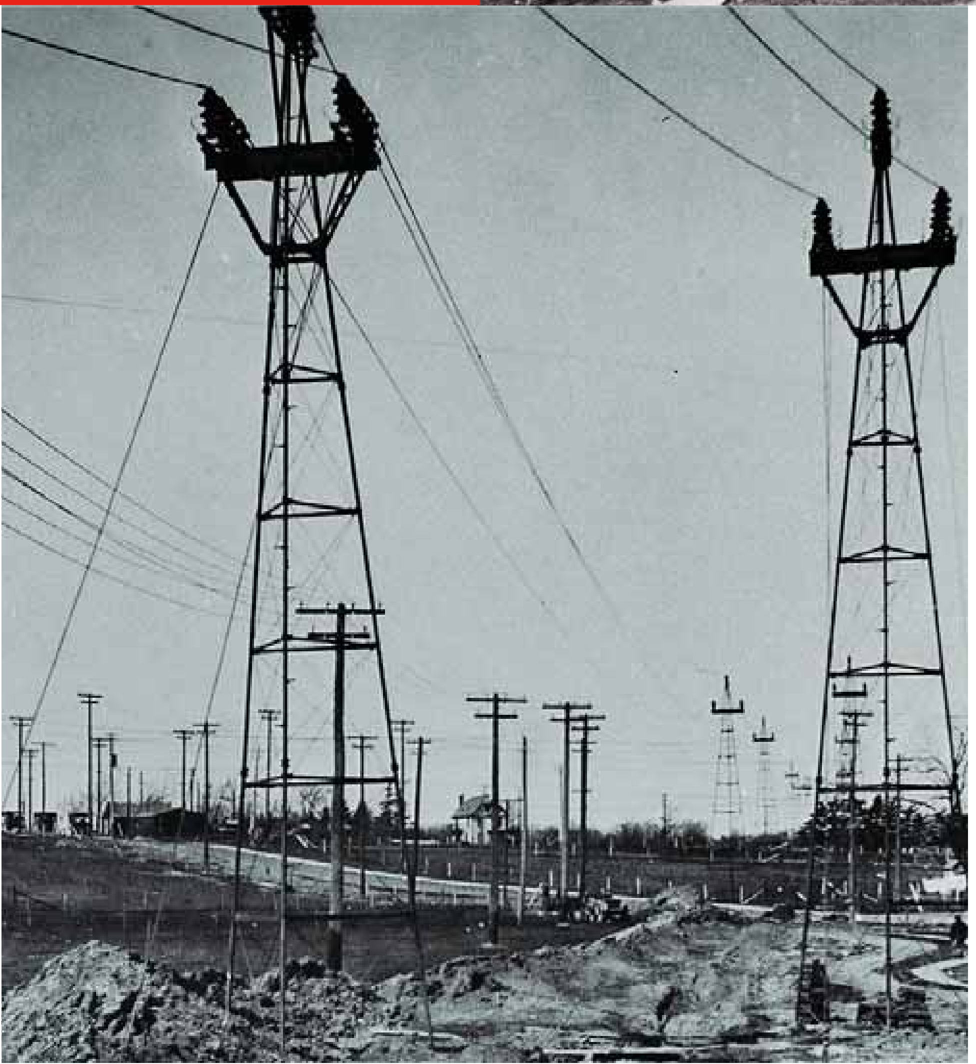
2004
Hydro One opens the Ontario Grid Control Centre, centralizing operation of the province's transmission and distribution centre in one facility.

2005
Work is completed on the Parkway transformer station to improve supply reliability and enable the shutdown of the coal-fired Lakeview generating station.

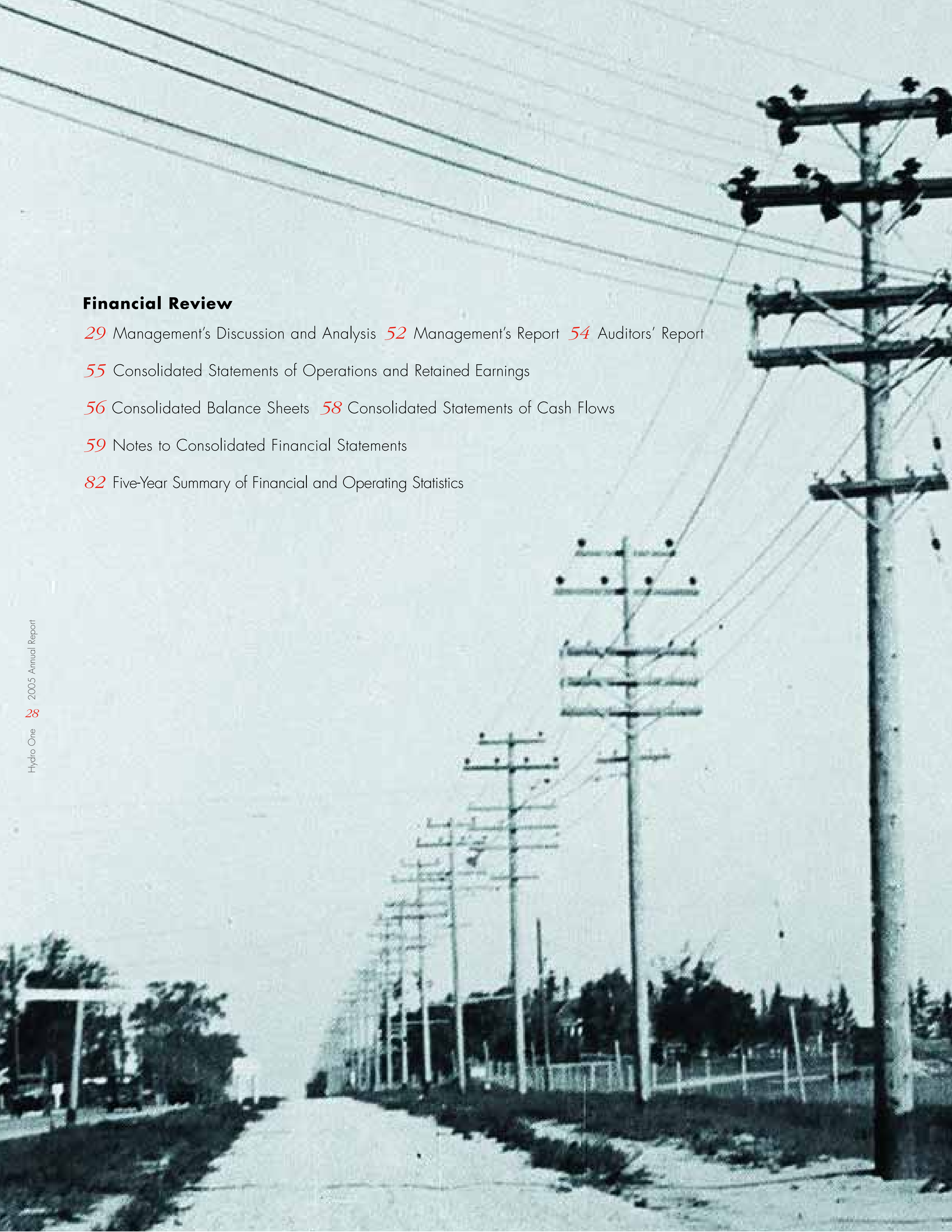
Present Day
As it was a century ago, it is today. The government of Ontario fully owns Hydro One, one of North America's largest transmission and distribution companies with almost 30,000 km of transmission lines, and approximately 1.3 million distribution customers.

Right: When the Adam Beck Circus was on the move, crowds would gather at its stops to see the latest electrically powered equipment.





Left: The earliest steel towers and high-voltage lines were quite a different shape than the one's we use today. This photo was taken in 1910, near Niagara Falls.



Financial Review

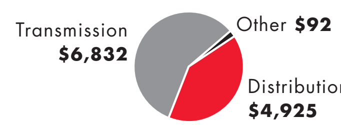
We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2005 and 2004.

OVERVIEW

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). We are the leading electricity transmitter and distributor in Ontario. Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2005, 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.

Transmission

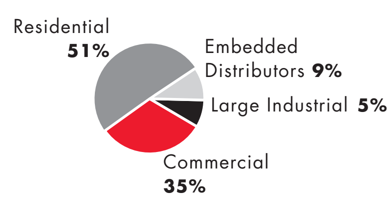
Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2005, we earned total transmission revenues of $1,310 million primarily by transmitting approximately 157 TWhs of electricity, directly or indirectly, to more than 4 million customers. Our transmission 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 4,000 MWs and exports of approximately 5,800 MWs of electricity. In terms of assets, our transmission business is our largest segment, representing more than 50% of our total assets.



TOTAL ASSETS
December 31, 2005
(Cdn $ millions)

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 50 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. As illustrated in the accompanying chart, approximately half of our distribution revenues are earned from our residential customers.



2005 DISTRIBUTION REVENUES

Other

Our other business segment contributed revenues of $21 million in 2005 and has assets of about $92 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. We are currently in the process of assessing our strategy with respect to these operations.

OVERVIEW (continued)

Our Strategy

In 2005, we maintained our strategic focus on our core operations and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value. We seek to achieve these goals by continuing our focus on the following strategies:

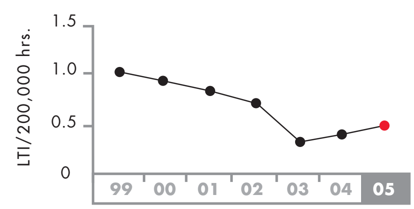
- *Safety:* Create and maintain an injury-free workplace with a concentrated focus on prevention of serious injury.
- *Customer Service:* Become a leading customer-focused company. We will undertake initiatives and deliver on actions in a timely manner to improve our customers' level of satisfaction. In particular, we will strive to build positive relationships with all of our customer segments, acknowledging the commercial requirements of our large and mid-sized customers.
- *Reliability:* Enhance the reliability of our transmission and distribution systems while continuing to develop and expand the transmission system to meet Ontario's future needs.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining an effective borrowing capability through stable credit quality and delivering appropriate financial returns to our shareholder.

Performance Measures and Targets

We measure and target our performance in all the above strategic areas. We largely met our challenging 2005 objectives, improving in a number of areas over 2004 levels, and are moving forward to meet our strategic goals.

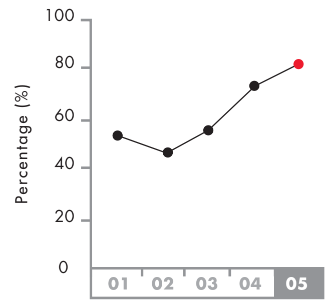
As we work in an environment with significant hazards, safety is our top priority. In 2005, we experienced an employee fatality at a transformer station. This unfortunate occurrence is a painful reminder of the workplace hazards that we deal with on a daily basis. Consequently, our focus remains on the goal of achieving zero injuries by 2006 for categories such as electrical incidents, falls and motor vehicle accidents where there is a high potential for serious injury. The number of serious lost time injuries has consistently remained at four per year over the last number of years. Although we did not achieve our aggressive safety targets for the year, the number of serious incidents in 2005 was 12% lower than 2004 and 28% lower than 2003.

As shown in the accompanying chart, since 1999 our lost-time incident frequency rate has dropped by about 50%, placing us in the top quartile of Canadian transmission and distribution companies. The majority of our 2005 lost-time incidents were related to minor injuries such as strains and slips. Going forward, we will continue to emphasize the importance of safety, with the goal of further improving our safety performance. This involves a sustained cultural change, with emphasis on human factors and the role of human traits in determining safe work performance. Planned safety initiatives include an injury and exertion prevention program, a coaching and mentoring program, developmental rotations, and a fleet safety program.



Lost-Time Incidents Frequency Rate

By addressing service issues, focusing on key areas of importance for our customers and upgrading our assets, we have made tangible improvements in customer satisfaction. We met all OEB targets for customer service. As shown in the accompanying chart, the level of satisfaction of our large transmission and local distribution company (LDC) customers improved by 14% over 2004 levels and 57% over 2003 results. Residential customer satisfaction levels remained consistently strong at 82%. Building on this momentum, we will continue to focus on improving the level of satisfaction of all our customers by undertaking initiatives which will streamline their points of contact and reduce our response time to customer requests.



Large Transmission & LDC Customer Satisfaction

We achieved all of our OEB targets for frequency and duration of interruptions. In particular, our transmission system reliability for frequency of interruptions out-performed our 2005 target and our 3-year average. The average duration of interruptions was within OEB targets, although slightly higher than the 3-year average (2002-2004), as a result of a late April freezing rainstorm in Southwestern Ontario and two outages on a remote line with limited accessibility. We continue to focus on the reliability of our distribution system. However reliability improvements are more challenging due to the rural nature of our system. Considering the impact of severe storms, we met our distribution reliability target for frequency and duration of interruptions and maintained the previous 3-year average (2002-2004). A number of key initiatives were undertaken during the year to enhance our performance, including improved crew scheduling to allow faster restoration response to unplanned outages. We also carried out detailed line reliability and customer impact analysis for use in developing investment requirements.

Strong financial performance again characterized our 2005 results and we maintained or improved our credit ratings on both our short and long-term debt.

REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates in proceedings through oral or written public hearings. These rates are based on the required level of revenue that the OEB allows for us to operate our regulated businesses, plus an approved rate of return.

Our industry has undergone significant restructuring over the past several years. On May 1, 2002, Ontario's wholesale and retail electricity markets were opened to competition (Open Access). Under Open Access, most consumers paid the wholesale spot market price for electricity as determined by demand and supply in the wholesale spot market administered by the Independent Electricity System Operator (IESO). In response to price volatility, the *Electricity Pricing, Conservation and Supply Act, 2002* was enacted to cap transmission and distribution rates and to fix the commodity price of electricity at 4.3 cents per kWh for low-volume and designated consumers.

As a result of the *Ontario Energy Board Amendment Act (Electricity Pricing), 2003*, the transmission and distribution rate caps were lifted. The fixed commodity price was replaced with a two-tiered pricing structure, effective April 1, 2004. Under this structure, low-volume and designated consumers paid 4.7 cents per kWh for the first 750 kWh of electricity consumed each month and 5.5 cents per kWh for electricity consumed over this threshold each month.

REGULATION (continued)

On December 9, 2004, the Ontario Legislature passed the *Electricity Restructuring Act, 2004* to provide consumers with stable prices that better reflect the true cost of electricity, facilitate new supply, and promote conservation and demand management. The act also created the Ontario Power Authority (OPA), which has a mandate to ensure an adequate, long-term supply of electricity in Ontario. The IESO continues to be responsible for overseeing and running the wholesale markets and ensuring the reliability of the integrated power system.

Under the new market structure, wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices for electricity. At the retail level, the OEB approved a Regulated Price Plan (RPP) for certain low-volume and designated consumers. The RPP maintained a two-tiered pricing structure, set new commodity prices, and introduced seasonal consumption thresholds for residential customers. The commodity price was based on an OEB forecast of the price of electricity over the period from April 1, 2005 to March 31, 2006 and was set at 5.0 cents per kWh for the lower tier and 5.8 cents per kWh for the upper tier. The consumption thresholds for residential customers were 750 kWh for the 2005 summer months (April 1 to October 31) and 1,000 kWh for the winter months (November 1 to April 30). For the 2006 summer months (May 1 to October 31), the threshold for residential customers will be 600 kWh. For all other RPP customers, the consumption threshold is 750 kWh year-round. The OEB intends to review these prices semi-annually starting May 1, 2006. The price plan also introduced time-of-use pricing for those customers with smart meters. Unexpected shortfalls or overpayments will be administered by the OPA and passed through to customers over the course of a year, starting on a price resetting date. As a result, our distribution business does not have commodity price risk.

On November 3, 2005, the Government of Ontario (Government) introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation, if passed, will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by 2007, with installation in all homes and businesses to be completed by 2010. Under the proposed legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. LDCs, including our distribution businesses owned and operated by our wholly-owned subsidiaries Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton), will own, install, operate and maintain the meters.

Transmission Rates

The IESO remits payments to us based on the uniform transmission rates approved by the OEB for all transmitters across Ontario. Existing rates were set based on cost of service rate regulation. The OEB approved a transmission revenue requirement that provides for cost recovery and includes a return on deemed common equity, which in the last rate-setting period was targeted to be 9.88%.

In October 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB will consider options to track net income excesses or deficiencies from OEB-approved returns for the period from January 1, 2006 until the revised transmission rates are implemented. The options identified by the OEB include the possible use of a regulatory deferral account or an earnings-sharing mechanism.

On November 23, 2005, we submitted a proposal to the OEB that any excess earnings be returned to customers in the form of transmission system expansion projects that are critical to the economic health of Ontario and to the secure operation of the system. The approval of any earnings sharing mechanism could have a significant impact on our net income. We participated in an oral hearing on this matter and we anticipate a decision from the OEB in the first quarter of 2006. We also anticipate submitting evidence this summer in preparation for a transmission rate hearing expected to be held this fall. A 1% change in the return on deemed common equity of the transmission business, would affect our net income by about $22 million.

On December 8, 2005, the OEB adjusted the revenue allocation factors for the Province's electricity transmitters. As a result, our share of overall provincial transmission revenue will decrease by approximately $13 million per year, beginning in 2006.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates are approved by the OEB, based on a revenue requirement that includes a rate of return. Our distribution rates continue to be set based on cost of service rate regulation. Our current rates include a targeted return of 9.88% on deemed common equity. In August 2005, we filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for our distribution business operated through Hydro One Networks. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. If approved, customers would see an average increase of 6% on their monthly bills starting in May 2006. This rate application is currently in the evidentiary phase. An oral hearing commenced in January 2006 and an OEB decision is anticipated later in the first quarter of 2006.

In December 2004, we received OEB approval to recover certain distribution-related deferral account balances, over the period ending April 30, 2008. The recovery of these prudently incurred costs was originally suspended by the *Electricity Pricing, Conservation and Supply Act, 2002*. These deferred amounts primarily include charges for low-voltage services to embedded LDCs and direct customers, market-ready transition costs, retail settlement variance account balances, and certain environmental costs. In March 2005, the OEB also approved our application to implement the final installment of a rate increase associated with moving toward our allowable return on equity that was originally to be effective for all LDCs on March 1, 2003. Our distribution rates were increased on April 1, 2005 to reflect these decisions.

We also filed a distribution rate application seeking approval for a $3 million increase in the 2006 distribution revenue requirement of Hydro One Brampton, which would result in customers seeing an average increase of 1% on their monthly bills starting in May 2006. This rate application is subject to a separate OEB process, independent of the Hydro One Networks' distribution application.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	2005	2004	$ Change	% Change
Transmission	**1,310**	1,262	48	4
Distribution	**3,085**	2,874	211	7
Other	**21**	17	4	24
	4,416	4,153	263	6
Average annual Ontario 60-minute peak demand *(MW)*[1]	**23,074**	22,375	699	3
Distribution – units distributed to customers *(TWh)*[1]	**29.7**	28.5	1.2	4

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

Transmission

Transmission revenues consist predominantly 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 the necessary revenues to support a transmission system that has sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather as well as economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

The increase in transmission revenues in 2005 primarily reflects the extreme weather conditions experienced during the summer of 2005, which was one of the hottest on record. Temperatures in excess of 30°C were common, resulting in the previous record for electricity consumption of 25,414 MW being exceeded on seven occasions. In July, the new record peak demand was set at 26,160 MW. Only the summers of 2002 and 1998 have been comparable since 1970. Peak demand increases, compared to 2004, were also experienced in some of the remaining months of the year. Ancillary transmission revenues were marginally lower this year.

Distribution

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

Distribution revenues increased in 2005 compared to last year mainly due to the recovery of higher purchased power costs of $144 million, as described below under "Purchased Power." The remaining increase primarily reflects an OEB-approved distribution tariff rate increase effective April 1, 2005, the recognition of low-voltage services revenues, and increased demand. The approved tariff increase was originally scheduled to be effective March 1, 2003, but was subsequently suspended for all LDCs by the *Electricity Pricing, Conservation and Supply Act, 2002*. During 2004, the low-voltage services revenues were deferred until a December 2004 prudence decision by the OEB allowed for regulatory recovery starting in 2005. Ancillary distribution revenues were lower this year primarily due to a lower level of assistance required by Florida Power and Light Company to repair hurricane damage in 2005. In 2004, our crews were called upon twice to provide hurricane recovery assistance, compared to once in 2005. Such assistance is carried out under a North American mutual-assistance agreement.

Under a new regulation issued in October 2005, RPP customers received the *Ontario Price Credit,* reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter, revenue and cost of power were both reduced by approximately $140 million, representing the amount refunded to customers. The application of the *Ontario Price Credit* did not result in any adjustment to net income in the current period or in previously reported periods.

Other

Other revenues were higher by $4 million compared to 2004 due to increased lit fibre revenues within our telecommunications business.

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 electricity, the IESO's wholesale market service charges, and transmission charges levied by the IESO. Prior to April 1, 2004, for certain low-volume and designated customers, the commodity price of electricity was fixed at 4.3 cents per kWh. On April 1, 2004, this fixed rate was replaced by an interim two-tiered pricing structure of 4.7 cents per kWh for the first 750 kWh consumed each month and 5.5 cents per kWh for electricity consumed over this threshold each month. On April 1, 2005, the interim pricing structure was replaced by the OEB's RPP which consists of a two-tiered pricing structure of 5.0 cents per kWh for the first 750 kWh consumed each month and 5.8 cents per kWh for any additional consumption. Effective November 1, 2005, the first 750 kWh threshold was increased to 1,000 kWh during the winter months for residential customers. Customers who are not eligible for the RPP continue to pay market prices for electricity, adjusted for the difference between market price and regulated and contract prices paid to generators under the *Electricity Restructuring Act, 2004*.

Purchased power costs increased by $144 million, or 7%, to $2,131 million in 2005 compared to last year. This increase primarily reflects higher demand of $84 million and higher commodity prices of approximately $60 million. Commodity prices reflect higher wholesale prices for customers who are not eligible for the RPP, partially offset by lower net prices for RPP customers. The increased commodity prices due to the implementation of the April 2004 and April 2005 pricing structures for RPP customers, were more than offset by the mandated *Ontario Price Credit* associated with lower commodity prices between April 1, 2004 and March 31, 2005 as described above under "Distribution Revenues."

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include 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)	2005	2004	$ Change	% Change
Transmission	**353**	356	(3)	(1)
Distribution	**413**	392	21	5
Other	**26**	23	3	13
	792	771	21	3

RESULTS OF OPERATIONS (continued)

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way were marginally lower than in 2004. Overall we maintained our necessary work program levels consistent with our safety and reliability standards at our transmission sites. We did experience lower station maintenance costs across our system as conditions, primarily caused by the abnormally high temperatures during the summer months, constrained our ability to take our equipment out of service for maintenance. As a result, additional maintenance is expected to be required in future periods. The reduction in these work program expenditures was substantially offset by higher expenditures from increased brush and line clearing activities, higher preventive maintenance on certain of our facilities and higher costs related to the reassignment of resources to support maintenance activities due to the smaller transmission capital program this year. Other cost reductions resulted from a labour disruption and from cost recoveries associated with insurance settlements and bad debts.

Distribution

Operation, maintenance and administration expenditures required by our distribution business to serve communities across Ontario were $21 million higher than last year. We maintained an enhanced forestry work program on our province-wide rights-of-way to improve reliability by reducing our trimming cycles. We also incurred increased expenditures to restore power due to intense storm activity this year. As required by the OEB, we also initiated our conservation and demand management programs in support of developing a conservation culture. These overall cost increases were partially offset by lower costs resulting from a labour disruption and lower costs required to provide emergency hurricane relief to Florida Power and Light Company.

Other

Other operation, maintenance and administration costs were $3 million higher this year compared to 2004. This result reflects the higher level of lit fibre service revenues.

Depreciation and Amortization

Depreciation and amortization expense for 2005 increased by $7 million, or 1%, to $487 million relative to the comparative period. This change primarily results from increased fixed asset removal costs, including such costs attributable to our Niagara Reinforcement Project which started in the last quarter of 2005.

Financing Charges

Financing charges decreased by $6 million, or 2%, to $325 million compared to last year. The reduction was due to the effect of higher interest capitalization on our regulatory assets associated with the OEB's December 9, 2004 rate decision, partially offset by the impact of higher average debt levels.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* 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 relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes increased by $21 million, or 12%, to $198 million compared to 2004. A higher tax provision on higher income this year was partially offset by the recognition of a tax benefit of approximately $21 million relating to accumulated tax losses of a subsidiary. The tax benefit was recognized during the second quarter of 2005 after an agreement was reached to settle an outstanding legal claim that allowed for the dissolution of the subsidiary.

Net Income

Net income in 2005 increased $76 million, or 19%, to $483 million compared to 2004, excluding the impact of last year's one-time regulatory recovery. This increase primarily reflects higher tariff revenues within our transmission and distribution businesses. We maintained an intense focus on the operation of our equipment during the abnormally hot summer to ensure continuous, reliable delivery of electricity to Ontarians. In addition, we experienced a favourable impact on our results due to the recognition of a tax benefit related to the accumulated tax losses of one of our subsidiaries. These impacts were partially offset by higher operations, maintenance and administration expenditures, primarily within our province-wide distribution business. Including last year's one-time regulatory recovery, which was caused by the suspension of an approved rate increase under the *Electricity Pricing, Conservation and Supply Act, 2002*, our net income decreased by $15 million, or 3%, compared to 2004.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2004 through December 31, 2005. 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)	2005				2004			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues[1, 2, 3]	**1,025**	**1,179**	**1,018**	**1,194**	1,074	1,018	960	1,101
Net income[1, 2, 3, 4]	**104**	**133**	**115**	**131**	186	133	59	120
Net income to common shareholder[1, 2, 3, 4]	**99**	**129**	**110**	**127**	181	129	55	115

[1] Both the revenue and the net income amounts reported in the first and second quarter of 2004 have been reduced by $5 million and $6 million, respectively, to reflect a change in interperiod allocations.

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

[3] Under a new regulation issued in October 2005, RPP customers received a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and cost of power were both reduced by approximately $140 million. The application of the one-time credit did not result in any adjustment to net income in the current period or previously reported periods.

[4] As a result of submitted oral and written evidence, 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 in our May 31, 2004 submission. Consequently, net income for the fourth quarter of 2004 includes a regulatory recovery of $91 million.

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 sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, and 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)	2005	2004
Operating activities	**1,170**	911
Investing activities		
Capital expenditures	**(691)**	(727)
Financing activities		
Long-term debt issued	**500**	540
Long-term debt retired	**(648)**	(472)
Short-term notes payable	**(40)**	15
Dividends paid	**(291)**	(265)
Other financing and investing activities	**–**	26
Net change in cash and cash equivalents	**–**	28

Operating Activities

Net cash generated from operations increased by $259 million compared to 2004. This increase is primarily attributable to lower working capital requirements and a higher level of net income this year, excluding last year's one-time non-cash regulatory recovery. Our working capital requirements have primarily been affected by funding received from the IESO to process the mandated credit for RPP customers. This funding had a positive impact on working capital due to the timing of customer billing cycles. In addition, changes in our trade accounts payable balances reflecting our work program and the timing of tax payments contributed to the reduction in our working capital requirements.

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 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by a $750 million committed revolving credit facility with a syndicate of banks which matures in August 2006 and has a two-year extension option. As at December 31, 2005, we had no short-term notes outstanding. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our medium-term note program. Our notes and debentures mature between 2006 and 2043. We currently plan to refinance maturing debt principally through our medium-term note program, which was renewed in June 2005. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which the full amount is remaining and is currently available until July 2007.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
Standard & Poor's Ratings Services Inc.	A-1	A
Dominion Bond Rating Service Inc.	R-1 (low)	A
Moody's Investors Service Inc.	Prime-1	Aa3

We have 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 agreement that supports our $750 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides 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. As at December 31, 2005, we were in compliance with all of these covenants and limitations.

During 2005, we issued $500 million in long-term debt prior to the renewal of our medium-term note program and we repaid $648 million in maturing long-term debt. In comparison, during 2004 we issued $540 million in debt under our medium-term note program and we repaid $472 million in maturing long-term debt. In 2005, we decreased our short-term notes by $40 million compared to an increase of $15 million in 2004.

In 2005, we paid dividends to the Province in the amount of $291 million, consisting of $273 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $247 million and preferred dividends of $18 million.

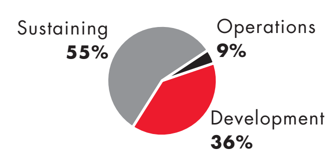
Investing Activities

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)	2005	2004	$ Change	% Change
Transmission	**349**	432	(83)	(19)
Distribution	**338**	288	50	17
Other	**4**	7	(3)	(43)
	691	727	(36)	(5)

Transmission

Transmission capital expenditures were $349 million and $432 million in 2005 and 2004, respectively. Capital expenditures to expand and reinforce our transmission system decreased by $98 million to $125 million, primarily due to the completion of the Parkway transformer station this year. This project was initiated last year in response to growing loads and the closure of the Lakeview generating station. In 2004, we also completed our Ontario Grid Control Centre, enabling us to access cost efficiencies and allowing for improved customer response and advanced monitoring and analysis of our system. Late in the current year, we began construction of our Niagara Reinforcement Project. This critical infrastructure project includes a new transmission line which will alleviate transmission constraints in the Niagara region and allow additional clean energy from Niagara Falls and electricity imports to reach consumers. Cost recovery will be subject to the provision of evidence regarding the economic benefits of this project. Capital expenditures incurred to sustain our transmission lines and stations, and to maintain reliability, increased by $17 million to $193 million, reflecting refurbishment and minor component replacement projects which did not require our equipment to be taken out of service. However, due to constraints, such as the effect of an abnormally hot summer, we did not fully complete our planned sustainment program this year and we anticipate completing such projects in future periods. Our other capital expenditures decreased marginally by $2 million to $31 million.

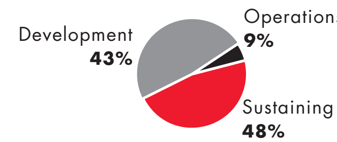


2005 Transmission Capital Expenditures

LIQUIDITY AND CAPITAL RESOURCES (continued)

Distribution

Distribution capital expenditures were $338 million in 2005 compared to $288 million in 2004. Capital expenditures to sustain our distribution system increased by $46 million to $162 million, primarily due to increased investments related to storm damage recovery and transport and work equipment, including new brushing equipment expected to further enhance productivity within our forestry program. In addition, other capital expenditures to support our distribution network increased by $14 million to $29 million, primarily as a result of increased investments in information technology assets. Capital expenditures to expand and reinforce the low-voltage distribution system declined by $10 million to $147 million. This reduction reflects the reprioritization of work during the labour disruption, partially offset by increased demand for new connections.



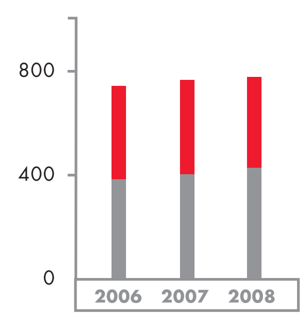
2005 Distribution Capital Expenditures

Other

Other capital expenditures decreased by $3 million to $4 million. The level of expenditures reflects the timing of projects to meet customer demand for new services.

Future Capital Expenditures

Our capital expenditures in 2006 are budgeted at about $755 million, an increase of approximately $65 million over 2005 actual levels but consistent with 2005 budgeted levels. Capital expenditures for 2005 were lower than budget due to constrained outage availability resulting from the hot summer, as well as the impact of a labour disruption and our efforts to focus on delivering the capital projects with the highest priority. The 2006 capital budgets for our transmission and distribution businesses are about $390 million and $360 million, respectively. Other capital expenditures are budgeted at $5 million and are largely minor enhancements to our fibre-optic network in support of our telecommunications business. Capital expenditures, as shown in the accompanying chart, are expected to increase marginally over the next few years, primarily reflecting investments in transmission infrastructure. There is also the potential for large-scale transmission infrastructure projects and conservation initiatives not included within our current investment plan due to the level of uncertainty, complexity and cost. These potential investments, together with our planned capital expenditures program, are discussed below.



Future Capital Expenditures
(Cdn $ millions)

Transmission

Transmission system capital expenditures are expected to increase marginally over the period 2006 to 2008. Given continuing supply constraints, we will focus on critical transmission assets that support generation facilities, such as our 500kV lines and high-voltage switch yards. The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure. Key transmission investment areas are power equipment, protection and control equipment, ancillary systems and overhead and underground lines.

In addition, increased expenditure levels reflect transmission development work identified in our 10-year transmission plan, *Transmission Solutions 2005-2014*. These investments ensure that growing area supply needs, reliability requirements, and needs for increased access to the Ontario market are successfully met. A number of specific development initiatives are nearing completion or are well underway, including the Niagara Reinforcement Project and the construction of underground transmission cables to improve reliability in downtown Toronto.

At the local level, we continue to proactively address supply needs with our customers. For projects required to provide reliable supply to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes continues to be essential for maintaining the safe and reliable delivery of electricity. Examples of projects initiated to meet the growing needs of our customers include: Holland transformer station to serve northern York Region; Belle River transformer station to serve areas in Essex County; and Everett transformer station to serve southern Simcoe County. In addition, we are in discussions with a number of customers in the areas of Kingston, Durham Region, Burlington, and in a number of communities in Western and Northwestern Ontario.

The timing of many of these projects and others is uncertain as they are dependent upon need and, in some instances, require approvals by various regulatory bodies, as well as negotiations with customers, neighbouring utilities and other stakeholders. In addition, the OPA is expected to file an Integrated Power System Plan (IPSP) with the OEB during the summer of 2006. The IPSP will detail how Ontario's medium and long-term electricity needs will be met, consistent with the public interest. Using our 10-year transmission plan as a basis, we continue to work closely with the OPA on transmission solutions to address these needs.

The IPSP could include additional large-scale projects which are not currently included in our investment plan. These major initiatives may be necessary to increase the supply of electricity and to support the closure of coal-fired generation. We are actively participating in various working groups involving key government and electricity industry stakeholders in this respect. In particular, we continue to develop interconnection enhancement possibilities with our neighbouring utilities, including those required to support the Government's existing and future power purchase agreements with the Province of Manitoba which could increase transmission capacity by up to 1500 MW. Planning also continues on a number of other major initiatives, including the development of a major new supply line between Central and Western Ontario to accommodate new power developments and enable the shutdown of the Nanticoke coal-fired generation station. As well, planning continues on the development of a major new supply line to Toronto to enhance reliability. We would not undertake these large complex projects without a reasonable expectation that such expenditures would be recoverable in our rates.

Distribution

We continue to replace and improve our aging distribution asset base in order to improve system reliability. Increasing investments will be made within the distribution business, in particular reflecting increased wood pole replacements, feeder sectionalization and defect management. Across Ontario, we are continuing the replacement of older distribution systems with higher voltage and more current-standard installations. In addition, we are constructing new lines and stations in response to system growth forecasts or high load relief requirements, and will focus our efforts on making the distribution system more efficient. Examples of some of these initiatives include a new station to serve northern King Township and various projects to reduce losses on our distribution system.

LIQUIDITY AND CAPITAL RESOURCES (continued)

In addition, we are moving forward with initiatives to improve the reliability performance of our distribution system. Cost-effective improvements can be achieved by enhancing maintenance practices and the operability of the system by continuing to add sectionalizing capability at selected locations to reduce the number of customers affected by system outages. We will continue to implement a range of conservation and demand management programs consistent with our OEB-approved program.

In November, 2005, the Government introduced the *Energy Conservation Responsibility Act, 2005*. The proposed legislation, if passed, will provide the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be complete by 2010. Under the proposed legislation, a new entity will oversee the communications systems and technologies, collect and manage data, and may facilitate meter procurement. LDCs will own, install, operate and maintain the meters and continue to bill their customers. This program is expected to increase our expenditure levels and reduce our tariff revenues. It is estimated that our costs could range from $600 million to $1.2 billion, depending on the technology platform selected and the associated infrastructure requirements. This estimate includes not only the acquisition and installation costs of smart meters, but also the costs of necessary billing system upgrades, telecommunication infrastructure and data management systems. Although there continues to be a high level of uncertainty surrounding the implementation details of the smart meters program, we anticipate that the resulting expenditures will be recoverable. The OEB is examining how to address any negative impacts associated with load reductions.

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, 2005 (Canadian dollars in millions)	Total	2006	2007/2008	2009/2010	After 2010
Contractual Obligations *(due by year):*					
Long-term debt	5,084	589	895	800	2,800
Inergi LP (Inergi) outsourcing agreement[1]	600	110	205	183	102
Operating lease commitments	17	5	8	4	—
Total Contractual Obligations	**5,701**	**704**	**1,108**	**987**	**2,902**
Other Commercial Commitments *(by year of expiry):*					
Bank line[2]	750	750	—	—	—
Letters of credit[3]	106	106	—	—	—
Guarantees[3]	275	275	—	—	—
Pension[4]	89	81	8	—	—
Total Other Commercial Commitments	**1,220**	**1,212**	**8**	**—**	**—**

[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.

[2] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2006, with a two-year extension option.

[3] We currently have bank letters of credit of $82 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $21 million and parental guarantees of $275 million. Currently, the amount of prudential support that we provide in the form of bank letters of credit to the IESO is based on our highest long-term credit rating which is in the "Aa" category. The amount of bank letters of credit provided would need to increase if our highest credit rating deteriorated. For example, if our credit rating declined to the "A" category, the amount of bank letters of credit required to meet our prudential support obligation would be 1.7 times our current amount, and if our credit ratings declined to "BBB" category, the amount of bank letters of credit required to meet our prudential support obligation would be 3.3 times the current amount. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[4] Contributions to the pension fund are made one-month in arrears. Contributions after 2006 will be based on an actuarial valuation effective no later than December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Based on current factors, the company currently estimates annual pension contributions for 2007 and beyond to be in the range of $100 million.

The long-term debt amounts in the above table 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 within our capital expenditures, but these financing charges are not reflected in the above table. 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.

RISK MANAGEMENT

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. The Hydro One Leadership Team, comprising 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 review of our risk profile and practices and our Chief Financial Officer 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, is 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 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.

Regulatory Risk

On August 17, 2005, we filed a rate application seeking approval for a $160 million increase in the 2006 revenue requirement of Hydro One Networks' distribution business. As this is our first full cost of service rate submission since 1999 and as recent rate increases and commodity price increases have increased customer bills, we expect this submission to be closely examined by the OEB and intervenors. This could result in increased regulatory risk. For example, past or future expenditures could be disallowed or elements of the approved revenue requirement could be delayed. In addition, within the scope of this review, the OEB will examine the recoverability of certain pension costs incurred within our distribution business and recorded in a regulatory asset account. In accordance with an order from the OEB, we deferred the non-capital portion of our distribution-related pension costs incurred in 2004 and 2005 as a regulatory asset. These deferred expenditures amounted to $76 million as at December 31, 2005, inclusive of interest. Should the OEB determine that some of these expenditures are not recoverable from customers, any disallowed amount will be charged to the results of operations when the decision is rendered.

RISK MANAGEMENT (continued)

The OEB's December 9, 2004 decision, which allowed for regulatory recovery of the majority of the regulatory asset amounts we applied for, has significantly reduced the proportion of our total regulatory asset balance at risk for future disallowance. However, there may still be some residual risk of future OEB disallowance of unreviewed account balances. In the event that some of these amounts are disallowed by the OEB during our 2006 rate review, any disallowed amount will be charged to the results of operations when the decision is rendered.

On October 26, 2005, the OEB initiated a proceeding to approve revenue requirements for our transmission business for the years 2006, 2007 and 2008. For the period from January 1, 2006 until revised rates are implemented, the OEB intends to track net income in excess of the currently approved returns. Tracking options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism. This results in a risk of having some of our transmission revenues (for the period from January 1, 2006 until new rates are implemented) recaptured if excess earnings occur. We have proposed an earnings-sharing mechanism that would result in any over earnings being returned to customers in the form of transmission system expansion projects that are critical to the economy of Ontario and to the secure operation of the system. Our proposal is consistent with practices recently utilized in other North American jurisdictions requiring significant system investments. A hearing on our proposal was held on November 25, 2005 and a decision is expected by the OEB in the first quarter of 2006. The initiation of a transmission proceeding also results in similar risks to those faced by our distribution business as a result of our recent rate application.

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 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 impacted by successful conservation and demand management programs. The OEB has recognized the need to compensate utilities for any resulting lost revenue, but the approach, level and timing of any such compensation mechanism are yet to be determined. We are also subject to risk of revenue loss from other factors. For example, recent revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets and compensating us by paying the net book value of bypassed assets as well as costs of removal and environmental remediation. This code revision could result in compensation that is not consistent with the value of retaining the assets. The *Transmission System Code* enables us to challenge investments by utility customers that may strand our assets. We intend to use this avenue to mitigate any substantive financial risks.

There is also a risk that we could be required to invest in large-scale transmission infrastructure projects and conservation initiatives, such as smart meters. While we expect these expenditures to be fully recoverable, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment in value and charges to our results of operations. We have no insurance for naturally occurring damage or catastrophe impacting our assets located outside of our transmission and distribution stations.

Ownership by the Province

The Province owns all of our outstanding shares and therefore controls our company. The Province has the power to determine the composition of our Board of Directors and may directly influence our major corporate decisions and business plans. As such, in making decisions that affect us, the Province can be expected to consider the best interests of all of the residents of Ontario as well as the specific interests of our company and our customers. Examples of areas where this balance must be exercised include structuring and regulating our company and Ontario's electricity industry, regulating environmental issues and determining the amounts to be paid by us as dividends.

Labour Risk

Approximately 25% of our staff are eligible for retirement by 2008. We expect the skilled labour market for our industry to be highly competitive in the future. If we are not able to attract or retain sufficient qualified staff, our operations and financial condition could be adversely affected.

We have a defined benefit registered pension plan for the majority of our employees. Our contributions to the pension plan are based on periodic actuarial valuations. Our most recent actuarial valuation, covering the period January 1, 2004 to December 31, 2006 inclusive, was filed with the Financial Services Commission of Ontario in September 2004. Under this valuation, we are obligated to make annual cash contributions to the pension plan of approximately $80 million per year. The amount of the contributions that may be required after December 31, 2006 will depend on future investment returns, changes in benefits or actuarial assumptions.

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals (The Society). As a result, in the case of future labour disputes we could face some degree of operational risk related to continued compliance with our license requirements of providing service to customers. We could also face financial risk related to our ability to negotiate collective agreements consistent with our rates. Existing collective agreements with the PWU and The Society expire in 2008.

Environmental Risk

We are subject to federal, provincial and municipal environmental regulations that are subject to change. Failure to comply could lead to government orders requiring us to take specific actions or could subject us to fines, penalties, or claims by third parties. Conducting environmental assessments and seeking government approvals for the construction of facilities could result in delays and cost increases.

Future changes in environmental regulations may result in material changes to the expenditure estimates used to calculate the carrying values of our environmental liabilities and associated regulatory assets. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet.

International scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields 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, we could face litigation, be required to relocate some of our facilities, or face difficulties in locating and building new facilities.

RISK MANAGEMENT (continued)

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses on April 1, 1999 did not result in a transfer of title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Under the terms of our transfer orders, the OEFC will continue to hold these assets until we receive the federal and Indian band consents required for title transfer. After completion of title transfer, we expect our annual costs to exceed the amounts included in existing rate orders. If title transfer cannot be achieved, we expect that either the OEFC will continue to hold these assets or we will be required to relocate them, likely at significant expense. Such additional costs could have an adverse effect on our results of operations in the event we were unable to recover them in future rates.

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 and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our maturing long-term debt is refinanced. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a 1% change in interest rates on the refinancing of long-term debt maturing in 2006 and 2007 would have an impact on net income of approximately $2 million in 2006 and $5 million in 2007.

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. We do not trade in any energy derivatives. We currently have one interest rate swap contract outstanding with a notional principal amount of $40 million. The fair value of the swap contract is not significant.

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*.

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, 2005 amounted to $430 million and principally relate to employee future benefits other than pension, the regulatory asset recovery account (RARA), environmental costs, pension costs and low-voltage services. We have also recorded regulatory liabilities amounting to $525 million as at December 31, 2005. These amounts pertain primarily to pension costs, export and wheeling fees and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment, as it has for the employee future benefits other than pension regulatory asset, the environmental regulatory asset and the RARA, or if future OEB direction is judged to be probable. Most of the regulatory asset amounts have been reviewed by the OEB and confirmed as recoverable and any remaining balances will be reviewed as part of the OEB's 2006 review of our distribution business. 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.

Employee Future Benefits

We provide employee 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 in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $80 million per year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation no later than December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs on an accrual basis are also disclosed in the notes to the financial statements. 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 7.00% per annum is based on current expectations of long-term rates of return and reflects a pension asset mix consistent with the fund's investment policy of 57% held in equity securities, 38% held in corporate and government debt securities and 5% held in alternative assets consisting of hedge funds and private equity funds. 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 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. The return on pension plan assets exceeded this long-term assumption in 2005.

The weighted-average 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, 2005 have been reduced by 0.5% and 1.0%, varying by benefit plan, from those at December 31, 2004 in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities.

CRITICAL ACCOUNTING ESTIMATES (continued)

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 the service cost and interest cost of about $12 million per year.

Employee future benefits are included in labour costs and charged to results of operations or are capitalized as part of the cost of fixed assets. Changes in the 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

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 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 2005. As a result of our review, we determined that the carrying value of our goodwill has not been impaired.

EMERGING ACCOUNTING PRONOUNCEMENTS

Canadian Accounting Standards Board's Strategic Plan

On January 10, 2006, the Canadian Accounting Standards Board (AcSB) ratified a new strategic plan that will significantly affect the way financial reporting will be carried out in Canada. For companies such as ours, the plan entails converging Canadian generally accepted accounting principles (GAAP) with International Financial Reporting Standards over an expected five-year transitional period. The AcSB will develop and publish a detailed implementation plan for achieving convergence later in 2006. At the end of that period, Canadian GAAP will cease to exist as a separate, distinct basis of financial reporting for public companies. Due to the complexity of implementing this new accounting framework, we will begin our transition preparations early.

Accounting for Rate Regulated Operations

The AcSB has an active project to review GAAP applicable to enterprises with rate-regulated operations. The first phase resulted in the issue of Accounting Guideline AcG-19, *Disclosures by Entities Subject to Rate Regulation*. Our disclosures reflect these new requirements. In the second phase of its project, the AcSB plans to review whether regulatory accounting treatments, which are commonly applied throughout our industry, meet the definition of an asset or liability as defined by Canadian Institute of Chartered Accountants (CICA) Handbook Section 1000, *Financial Statement Concepts*. If the AcSB concludes that they do not, we would be required to discontinue the application of rate-regulated accounting. Specifically, we would no longer be able to recognize our regulatory assets and liabilities, which amounted to $430 million and $525 million, respectively at December 31, 2005. As well, we may be required to account for payments in lieu of corporate income taxes related to our regulated business on a liability basis. The net effect of these changes would be charged to either retained earnings or results of operations once the new accounting standard became effective, dependent on the transition rules. At this time, it is uncertain what decision the AcSB will reach. However, we do not believe that the outcome of this project will have a material financial impact on our company.

Financial Instruments

During 2005, the AcSB completed its project on the recognition and measurement of financial instruments by issuing new recommendations dealing with financial instruments and hedging and by introducing the concept of other comprehensive income. Under the new accounting standards, which come into effect for our 2007 fiscal year, all financial instruments, including derivatives, must be included on a company's balance sheet and measured at fair value or, in limited circumstances when fair value may not be the most relevant basis, at cost or amortized cost. The standards also specify when gains and losses resulting from changes in fair value are to be recognized in the Statement of Operations. Existing requirements for hedge accounting are extended and clarified. In addition, certain gains and losses will be reported as other comprehensive income. We are assessing the overall impact of the new accounting standards, but do not believe that their application will have a material financial impact on our company.

Accounting for Conditional Asset Retirement Obligations

In December 2005, the Emerging Issues Committee (EIC) of the CICA issued EIC-159, *Conditional Asset Retirement Obligations*. This pronouncement governs the accounting for asset retirement obligations where the method or timing of disposal of an asset is conditional on some future event. The new pronouncement is effective for annual and interim periods ending after March 31, 2006. We have reviewed the new EIC pronouncement and do not expect that it will have a material impact upon our company.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

As a reporting issuer, we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. In 2004, we initiated a formal project to evaluate our disclosure controls and internal controls over financial reporting. We completed our initial evaluation of our disclosure controls during the fourth quarter of 2005 and we anticipate completing our evaluation of our internal controls over financial reporting in 2006. Evaluations will continue to be conducted on an ongoing basis to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers).

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the consolidated financial statements for the year ended December 31, 2005, together with other financial information included in annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been put in place, and that these controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis.

OUTLOOK

We will continue to concentrate on our top strategic priorities, which are to create and maintain an injury-free workplace with a concentrated focus on the elimination of serious injuries or close calls having the potential to cause serious injury; to further enhance the reliability of our transmission and distribution networks; and to improve our customers' levels of satisfaction. To these ends, we have renewed our focus on incident prevention and proactive applications, and we are making significant investments to address asset condition and improve reliability by maintaining and selectively increasing work program spending levels. In particular, we will ensure

OUTLOOK (continued)

that Ontario's needs for performance from our aging transmission system under tight generation supply conditions are met. Key transmission investment areas include assets critical to supporting generating stations and reducing congestion on the main transmission grid, such as key transformer station upgrades and high-voltage line replacements, and protection and control equipment replacements. Key distribution investment areas include vegetation management, increased wood pole replacements, feeder sectionalization and defect management, as well as customer care programs and the conservation and demand management program.

Consistent with our 10-year transmission plan, *Transmission Solutions 2005–2014*, we will make the necessary investments in our transmission infrastructure to ensure that growing area supply needs, and system configuration and reliability requirements, are successfully met. In particular, we intend to make area supply improvements in the Greater Toronto Area (including central Toronto and adjoining communities) as well as across Ontario. Further, we will complete the Niagara Reinforcement Project and we expect to undertake other reinforcement projects as the needs for transmission system investments are further identified by the OPA in its pending IPSP. As part of these initiatives, we will work closely with the OPA, the OEB, and other stakeholders, related or affected parties.

There is significant potential for the IPSP to include large scale transmission infrastructure investments not currently included within our investment plans. Examples include the Manitoba-Ontario high capacity lines, major new supply lines to Toronto, and new generation investment projects including those related to the retirement of coal-fired generation. Funding is also not included for the implementation of smart meters. We would need to reach agreements with all affected parties and have a reasonable expectation of recovery before proceeding with such large, complex undertakings.

The Province is continuing to examine the state of the electricity market and industry within Ontario. While we are not anticipating structural changes, such changes are possible, for example in the form of electricity distribution sector rationalization or as the result of municipal border dispute settlements. We will continue to work with the Government to assist them in their deliberations and will work cooperatively to implement any changes. In the interim, the Government expects us not to enter into further transactions involving the acquisition or divestment of LDCs or distribution assets.

With the amendments to the legislation affecting the electricity industry and the OEB's mandate, the approval for recovery of distribution regulatory assets in December 2004 and the anticipated distribution rate increases in 2006, we anticipate a stable regulatory environment for our distribution business going forward. However, the OEB has initiated a review of our revenue requirement for the transmission business and we are anticipating a decision in the first quarter of 2006 regarding a proposed earnings sharing mechanism. Given the need for transmission infrastructure across the province to ensure reliability and economic vitality, we proposed that any excess earnings subject to a sharing mechanism be utilized to fund these projects. We will prepare our regulatory evidence in the interest of all Ontarians.

Through the outlook period, we anticipate that our financial returns will be sufficient to maintain a healthy financial condition, stable credit quality and consistent credit ratings on our long-term debt.

FORWARD LOOKING STATEMENTS AND INFORMATION

We have included forward-looking statements in this report that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. Any statement contained in this document that is not current or historical is a forward-looking statement. We have based these forward-looking statements on historical experience, current conditions and various assumptions believed to be reasonable in the circumstances. Actual results could differ materially from those projected in the forward-looking statements. Because of these risks, uncertainties and assumptions, undue reliance should not be placed on these forward-looking statements. Except to the extent required by applicable securities laws and regulations, we undertake no obligation to update or revise any of these forward-looking statements, whether to reflect new information, future events or otherwise.

This management's discussion and analysis is dated as at February 15, 2006. 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 15, 2006.

In meeting the 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. 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 Ernst & Young 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 generally accepted accounting principles. The Auditors' Report, which appears on page 54, 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 Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, and related disclosure controls and procedures, pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Tom Parkinson
President and Chief Executive Officer

Beth Summers
Chief Financial Officer

Executive Committee

Beth Summers
Chief Financial Officer

Tom Parkinson
President and Chief Executive Officer

Laura Formusa
General Counsel and Secretary

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2005 and December 31, 2004, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2005. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2005 and December 31, 2004, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2005, in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Toronto, Canada

February 15, 2006

CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Revenues		
Transmission *(Note 15)*	1,310	1,262
Distribution *(Notes 3 and 15)*	3,085	2,874
Other	21	17
	4,416	4,153
Costs		
Purchased power *(Notes 3 and 15)*	2,131	1,987
Operation, maintenance and administration	792	771
Depreciation and amortization *(Note 5)*	487	480
	3,410	3,238
Regulatory recovery *(Note 4)*	–	91
Income before financing charges and provision for payments in lieu of corporate income taxes	1,006	1,006
Financing charges *(Note 6)*	325	331
Income before provision for payments in lieu of corporate income taxes	681	675
Provision for payments in lieu of corporate income taxes *(Notes 7 and 15)*	198	177
Net income	483	498
Basic and fully diluted earnings per common share (Canadian dollars) *(Note 14)*	4,652	4,798

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Retained earnings, January 1	887	654
Net income	483	498
Dividends *(Note 14)*	(291)	(265)
Retained earnings, December 31	1,079	887

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2005	2004
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $18 million; 2004 - $18 million) *(Note 15)*	622	707
Materials and supplies	56	47
	678	754
Fixed assets *(Note 8)*:		
Fixed assets in service	15,553	14,940
Less: accumulated depreciation	5,818	5,475
	9,735	9,465
Construction in progress	381	348
	10,116	9,813
Other long-term assets:		
Deferred pension asset *(Note 12)*	449	534
Regulatory assets *(Note 9)*	430	443
Goodwill	133	133
Long-term accounts receivable and other assets	20	25
Deferred debt costs	23	23
	1,055	1,158
Total assets	11,849	11,725

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2005	2004
Liabilities		
Current liabilities:		
Bank indebtedness	**9**	9
Accounts payable and accrued charges *(Note 15)*	**700**	630
Accrued interest	**43**	44
Short-term notes payable *(Note 10)*	**–**	40
Long-term debt payable within one year *(Note 10)*	**589**	539
	1,341	1,262
Long-term debt *(Note 10)*	**4,466**	4,613
Other long-term liabilities:		
Regulatory liabilities *(Note 9)*	**525**	576
Employee future benefits other than pension *(Note 12)*	**716**	654
Environmental liabilities *(Note 13)*	**64**	74
Long-term accounts payable and accrued charges	**21**	22
	1,326	1,326
Total liabilities	**7,133**	7,201
Contingencies and commitments *(Notes 11, 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	**1,079**	887
Total shareholder's equity	**4,716**	4,524
Total liabilities and shareholder's equity	**11,849**	11,725

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

Rita Burak
Chair

Eileen Mercier
Chair, Audit and Finance Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	2005	2004
Operating activities		
Net income	**483**	498
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	**446**	446
Amortization of discount	**59**	62
Low-voltage services	**(24)**	—
Retail settlement variance accounts	**12**	29
Regulatory recovery *(Note 4)*	**–**	(91)
	976	944
Changes in non-cash balances related to operations *(Note 16)*	**194**	(33)
Net cash from operating activities	**1,170**	911
Investing activities		
Capital expenditures	**(691)**	(727)
Other assets	**9**	19
Net cash used in investing activities	**(682)**	(708)
Financing activities		
Long-term debt issued	**500**	540
Long-term debt retired	**(648)**	(472)
Short-term notes payable	**(40)**	15
Dividends paid	**(291)**	(265)
Termination of interest rate swap	**(10)**	—
Other	**1**	7
Net cash used in financing activities	**(488)**	(175)
Net change in cash and cash equivalents	**–**	28
Cash and cash equivalents, January 1	**(9)**	(37)
Cash and cash equivalents, December 31 *(Note 16)*	**(9)**	(9)

See accompanying 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 Ontario Energy Board (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 Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc., Hydro One Network Services Inc. (Hydro One Network Services), 1316664 Ontario Inc., formerly Ontario Hydro Energy Inc. (Ontario Hydro Energy), and Hydro One Markets Inc. (Hydro One Markets).

Hydro One Network Services will be dissolved pursuant to the *Business Corporations Act* (Ontario). The former Ontario Hydro Energy and Hydro One Markets were dissolved during 2005.

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 OEB. Existing transmission rates were set in 1999 to provide a targeted return of 9.88% on deemed common equity and were based on cost of service rate regulation. In October 2005, the OEB initiated a proceeding to review our transmission rates and to approve revenue requirements for 2006, 2007, and 2008. Revised transmission rates are expected to be implemented in 2007. In the first phase of this proceeding, the OEB will consider options to track net income excesses or deficiencies compared to approved returns for the period from January 1, 2006 until revised transmission rates are implemented. The options identified by the OEB could include the use of a regulatory deferral account or an earnings-sharing mechanism.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. Current distribution rates are based on a cost of service rate regulation model, which also includes a targeted return of 9.88% on deemed common equity. In August 2005, Hydro One Networks filed a distribution rate application seeking approval for a $160 million increase in the 2006 revenue requirement for its distribution business. This revenue requirement is based on achieving a 9.00% return on equity, consistent with the OEB's guidance for setting 2006 rates. An oral hearing commenced in January 2006 and an OEB decision is anticipated later in the first quarter of 2006.

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,

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

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. Specific regulatory assets and liabilities are disclosed in Note 9.

On December 9, 2004, the OEB issued its decision on the prudence of various regulatory deferral accounts incurred prior to December 31, 2003, plus related interest. As a result of the OEB's decision, the proportion of our regulatory assets subject to potential future OEB disallowance has been significantly reduced. However, regulatory asset amounts included in approved accounts that were recognized after December 31, 2003 have not yet been reviewed by the OEB. Similarly, the Company's deferred distribution-related pension expenditures have not yet been reviewed by the OEB for prudency. 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.

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, 2005 amounted to $377 million (2004 - $318 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.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent 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 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 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. 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 for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of any related asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of removing assets that the Company is legally required to remove, an 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.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

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 in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis. Financing costs are capitalized on fixed assets under construction based on the allowance for funds used during construction (2005 – 6.8%; 2004 - 7.0%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment and personal computers, which are depreciated on a declining balance basis.

Depreciation rates for the various classes of assets are based on their estimated service lives. The average estimated remaining service lives and service life ranges of fixed assets are:

	Estimated service lives (years)	
	Range	Average
Transmission	12 - 100	57
Distribution	15 - 75	41
Communication	7 - 40	21
Administration and service	5 - 50	41

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, 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 expense. Depreciation expense also includes the costs incurred to remove fixed assets where an asset retirement obligation has been recognized.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis from the year the changes can first be reflected in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies (LDCs) 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. Under Canadian Institute of Chartered Accountants Handbook Section 3062, *Goodwill and Other Intangible Assets*, 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.

Deferred Debt Costs

Deferred debt costs include the unamortized amounts of debt issuance costs. Deferred debt costs are amortized on an annuity basis over the period to maturity of the debt.

Derivative Financial Instruments

The Company periodically uses interest rate swap contracts to manage interest rate risks. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on an accrual basis. The Company formally designates its hedges, documents all hedging relationships and formally assesses hedge effectiveness. In the event a hedging relationship is extinguished or the relationship is found to be ineffective, realized or unrealized gains or losses are recognized in results of operations.

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

Discounts, Premiums and Hedging

Discounts, premiums and hedging gains and losses are amortized over the period of the related debt.

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.

2. SIGNIFICANT ACCOUNTING POLICIES (continued)

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net 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 recognized 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.

3. ELECTRICITY CREDITS TO CUSTOMERS

Under a new regulation issued in October 2005, Regulated Price Plan customers receive a one-time credit reflecting a lower cost of power than the fixed commodity price between April 1, 2004 and March 31, 2005. In the fourth quarter of 2005, revenue and purchased power costs were each reduced by $140 million. The application of the one-time credit did not result in any adjustment to net income in the current or previously reported periods.

4. REGULATORY RECOVERY

The *Electricity Pricing, Conservation and Supply Act, 2002*, suspended a previously approved rate increase related to annual low-voltage services costs for embedded LDCs and direct customers. The associated costs are charged annually to the Company's results of operations. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002*, also allowed for establishment of a regulatory deferral account to record suspended low-voltage services amounts to be recovered from future customers. Due to uncertainty of recovery, amounts recorded in this regulatory deferral account between May 1, 2002 and December 9, 2004 were not previously recognized as regulatory assets. Similarly, the Company did not reflect certain other costs, such as interest, as regulatory assets in prior years' financial statements.

On May 31, 2004, Hydro One applied for recovery of approximately $156 million included within various regulatory deferral accounts prior to December 31, 2003. The requested recovery primarily included the low-voltage services amounts not previously recognized as regulatory assets, as well as interest on all of the requested balances. As a result of the oral and written evidence submitted by Hydro One, the OEB issued a decision on December 9, 2004 regarding the prudence of the distribution-related deferral account balances included in the application. The OEB approved all but approximately $12 million of the requested amount for recovery over the period ending April 30, 2008. As a result of this successful regulatory recovery, the Company recorded an increase in its regulatory asset balance, which primarily reflects future recovery of costs that had been previously charged to results of operations without recognition of corresponding revenue.

The 2004 regulatory recovery consisted of the following components:

Year ended December 31 (Canadian dollars in millions)	2004
Low-voltage services – 2002	17
Low-voltage services – 2003	25
Low-voltage services – 2004	23
Interest accretion	18
Other	8
	91

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2005**	2004
Depreciation of fixed assets in service	**369**	370
Fixed asset removal costs	**41**	34
Amortization of regulatory and other assets	**77**	76
	487	480

6. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	**2005**	2004
Interest on short-term notes payable	**1**	1
Interest on long-term debt payable	**297**	286
Amortization of discount	**58**	62
Other	**5**	7
Less: Interest capitalized on construction in progress	**(21)**	(23)
Interest capitalized on regulatory assets	**(10)**	—
Interest earned on investments	**(5)**	(2)
	325	331

7. 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. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	2005	2004
Income before provision for PILs	681	675
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	246	244
(Decrease) increase resulting from:		
Net temporary differences:		
Pension contribution in excess of pension expense	(25)	(23)
Subsidiary loss carryforward	(21)	—
Regulatory recovery	–	(33)
Interest capitalized for accounting purposes but deducted for tax purposes	(11)	(8)
Employee future benefits other than pension expense in excess of cash payments	8	9
Environmental expenditures	(5)	(6)
Capital cost allowance less than (in excess of) depreciation and amortization	1	(7)
Other	(9)	(9)
Net temporary differences	(62)	(77)
Permanent differences:		
Large corporations tax	13	16
Other	1	(6)
Net permanent differences	14	10
Provision for PILs	198	177
Effective income tax rate	29.07%	26.22%

In May 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it was determined to be more likely than not that Hydro One would be able to access the subsidiary's accumulated tax losses and a future tax asset of approximately $21 million was recognized in the second quarter. As at December 31, 2005, approximately $9 million of this amount remains available for use in 2006.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2005, future income tax liabilities of $265 million (2004 - $224 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized on an accrual basis rather than under the taxes payable method. As a result, the provision for PILs would have been higher by approximately $41 million.

8. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2005				
Transmission	8,124	2,889	239	5,474
Distribution	5,319	1,995	65	3,389
Communication	752	344	46	454
Administration and service	877	530	31	378
Easements	481	60	—	421
	15,553	**5,818**	**381**	**10,116**
2004				
Transmission	7,833	2,753	249	5,329
Distribution	5,066	1,884	55	3,237
Communication	744	309	31	466
Administration and service	816	471	13	358
Easements	481	58	—	423
	14,940	5,475	348	9,813

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 \$21 million in 2005 (2004 - \$23 million).

9. 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 (see Notes 2 and 4):

December 31 (Canadian dollars in millions)	2005	2004
Regulatory assets:		
Employee future benefits other than pension	**126**	168
Regulatory asset recovery account	**88**	121
Environmental	**79**	89
Pension	**76**	34
Low-voltage services	**53**	26
Other	**8**	5
Total regulatory assets	**430**	443
Regulatory liabilities:		
Deferred pension	**449**	534
Export and wheeling fees	**32**	19
Retail settlement variance accounts	**30**	14
Other	**14**	9
Total regulatory liabilities	**525**	576

9. REGULATORY ASSETS AND LIABILITIES (continued)

Regulatory assets

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 3 years (2004 - 4 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately $42 million.

Regulatory asset recovery account (RARA)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances sought by Hydro One in its May 31, 2004 application (see Note 4). Recoverable amounts represent balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA includes 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. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower by approximately $20 million. In addition, related financing charges would have been higher by $7 million.

Environmental

Hydro One provides for estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized the net present value of these estimated future environmental expenditures as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. In the absence of rate regulated accounting, amortization expense in 2005 would have been lower and operation, maintenance and administration expense would have been higher by $14 million. During 2004, the Company identified an increased risk associated with potential offsite migration of contamination in storm water run-off from some of its transmission sites. Given the need to address this issue, in 2004 the Company adjusted its future land assessment and remediation expenditure estimate and increased its regulatory asset and offsetting environmental obligation by approximately $16 million (see Note 13). The OEB has the discretion to examine and assess the prudence and the timing of recovery of Hydro One's future regulatory expenditures.

Pension

In a July 14, 2004 decision, the OEB approved the Company's establishment of a regulatory account to record the Company's distribution-related pension contributions that would otherwise have been charged to results of operations. The regulatory asset also includes amounts payable to Inergi LP (Inergi) commencing in 2005 in respect of a risk sharing agreement related to the imbalance between pension fund assets and liabilities in respect of transferred staff (see Note 18). In its decision, the OEB concluded that prudently incurred expenditures of this type are generally recoverable as part of a general rate application. The Company has included a request for recovery as part of its distribution rate application currently under review by the OEB.

Low-voltage services

The OEB's December 9, 2004 decision allows for delayed recovery of previously approved low-voltage system amounts, within the RARA, for the period up to December 31, 2003. Given this decision, the Company has determined that it is probable that, at some future date, the OEB will also approve recovery of the low-voltage amounts attributable to 2004 and 2005, plus interest. As a result, the Company has recognized a regulatory asset reflecting this probable future recovery.

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 to 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, the Company's pension expense would have been recognized on an accrual basis rather than on a cash basis. As a result, operation, maintenance and administration expense would have been higher by approximately $38 million, assuming no regulatory deferral of distribution and Inergi pension-related amounts. In addition, related financing charges would have been higher by $4 million.

Export and wheeling fees

Consistent with the market rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MW on electricity exported outside of Ontario. The Company expects that amounts collected in respect of this export and wheeling fee, plus interest, will be taken into consideration by the OEB in assessing the revenue requirement of our transmission business as part of the Company's next general transmission rate application.

Retail settlement variance accounts

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 allows for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA. The Company anticipates that OEB will include the net balance of this regulatory account in future rates.

10. DEBT

December 31 (Canadian dollars in millions)	2005	2004
Short-term notes payable	–	40
Long-term debt:		
6.94% debentures due 2005	–	200
4.00% notes due 2005	–	339
4.10% notes due 2006[1]	–	109
4.15% notes due 2006	**280**	280
4.20% notes due 2006	**168**	168
4.30% notes due 2006	**141**	141
4.45% notes due 2007	**282**	282
4.55% notes due 2007	**73**	73
4.10% notes due 2007[2]	**40**	40
4.00% notes due 2008	**500**	500
3.95% notes due 2009	**400**	250
7.15% debentures due 2010	**400**	400
6.40% notes due 2011	**250**	250
5.77% notes due 2012	**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	**350**	—
6.59% notes due 2043	**315**	315
	5,084	5,232
Less: Long-term debt payable within one year	**(589)**	(539)
Net unamortized discounts	**(14)**	(73)
Unamortized hedging losses	**(15)**	(7)
Long-term debt	**4,466**	4,613

[1] 4.10% notes due 2006 were redeemed on December 16, 2005.

[2] Step-up coupon, after year 3 from 4.10% to 6.40%, extendable to 2011.

Short-term debt represents promissory notes issued pursuant to the Company's commercial paper program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2004, the notes had a weighted-average interest rate of 2.3%.

Hydro One has a $750 million committed and unused revolving credit facility with a syndicate of banks maturing in August 2006, with a two-year extension option. 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 program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which the full amount is remaining and is currently available until July 2007.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2005, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is 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)	Weighted Average Interest Rate (%)
1 year	589	4.2
2 years	395	4.4
3 years	500	4.0
4 years	400	4.0
5 years	400	7.2
	2,284	4.7
6 – 10 years	850	6.0
Over 10 years	1,950	6.6
	5,084	5.6

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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, based on year-end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	**2005**		2004	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	**5,084**	**5,697**	5,232	5,658

[1] The carrying value of long-term debt represents the par value of the notes and debentures.

Hydro One may enter into forward fixed interest rate swap agreements or forward sale agreements of Government of Canada bonds to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In 2004, Hydro One entered into a forward interest rate swap agreement with a notional principal amount of $100 million to lock in the interest rate of a future issuance planned for 2005. In 2005, Hydro One entered into an additional forward interest rate swap agreement to lock in a further $50 million in notional principal. During 2005, the Company terminated both forward interest rate agreements for a net cash payment of $10 million that is being amortized on an annuity basis over the thirty-year term of the related debt.

As at December 31, 2005, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. The interest rate swap is being accounted for as a fair value hedge. This agreement has a notional principal amount of $40 million.

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2005 (2004 - $nil).

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT (continued)

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2005, 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 single customer. As at December 31, 2005, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

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 Allocation

Hydro One's pension plan asset allocation at December 31, 2005 and 2004 was as follows:

	% of Plan Assets	
December 31	**2005**	2004
Equity securities	**60.6**	59.2
Debt securities	**36.2**	36.2
Other	**3.2**	4.6
	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 in the Province of $79 million and $83 million at December 31, 2005 and 2004 respectively.

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 on September 22, 2004, effective for December 31, 2003, the Company contributed $83 million to its pension plan in respect of 2005 (2004 - $74 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. Prior to 2004, the Company was not required to contribute to the pension plan because the last actuarial valuation at December 31, 2000 indicated that the plan had a surplus. Contributions after 2006 will be based on an actuarial valuation date no later than December 31, 2006 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2005, 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 $123 million in 2005 (2004 - $110 million).

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2005**	2004	**2005**	2004
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**4,862**	4,323	**966**	897
Current service cost	**83**	76	**26**	24
Interest cost	**277**	254	**57**	54
Benefits paid	**(248)**	(232)	**(40)**	(36)
Plan amendments	**–**	—	**1**	—
Net actuarial loss	**381**	441	**133**	27
Accrued benefit obligation, December 31	**5,355**	4,862	**1,143**	966
Change in plan assets				
Fair value of plan assets, January 1	**4,243**	3,939	**–**	—
Actual return on plan assets	**630**	458	**–**	—
Benefits paid	**(248)**	(232)	**–**	—
Employer's contributions[1]	**83**	74	**–**	—
Employees' contributions	**16**	16	**–**	—
Administrative expenses	**(11)**	(12)	**–**	—
Fair value of plan assets, December 31	**4,713**	4,243	**–**	—
Funded status				
(Unfunded benefit obligation)	**(642)**	(619)	**(1,143)**	(966)
Unamortized net actuarial losses	**1,069**	1,128	**385**	271
Unamortized past service costs	**22**	25	**6**	6
Deferred pension asset (accrued benefit liability)	**449**	534	**(752)**	(689)
Less: current portion	**–**	—	**36**	35
Deferred pension asset (long-term liability)	**449**	534	**(716)**	(654)

[1] In January, 2006, the Company made a contribution of $8 million in respect of 2005 (2005 - $7 million in respect of 2004).

12. EMPLOYEE FUTURE BENEFITS (continued)

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2005**	2004	**2005**	2004
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**67**	60	**26**	24
Interest cost	**277**	254	**57**	54
Actual return on plan asset net of expenses	**(619)**	(446)	**–**	—
Actuarial loss	**381**	441	**133**	27
Other	**–**	—	**–**	(1)
Costs arising in the period	**106**	309	**216**	104
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**327**	174	**–**	—
Actuarial gain	**(268)**	(362)	**(113)**	(11)
Plan amendments	**3**	3	**–**	1
Net periodic benefit cost[2]	**168**	124	**103**	94
Charged to results of operations[2]	**23**	22	**64**	56
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	—	**171**	124
Service cost and interest cost	**–**	—	**12**	11
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**–**	—	**(133)**	(108)
Service cost and interest cost	**–**	—	**(10)**	(9)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**7.00%**	7.00%	**–**	—
Weighted-average discount rate	**5.75%**	6.00%	**5.93%**	6.18%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.75%**	2.25%	**2.75%**	2.25%
Average remaining service life of employees (years)	**10**	12	**10**	11
Rate of increase in health care cost trend[3]	**–**	—	**4.40%**	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	**5.00%**	5.75%	**4.98%**	5.93%
Rate of compensation scale escalation (without merit)	**3.25%**	3.25%	**3.25%**	3.25%
Rate of cost of living increase	**2.50%**	2.75%	**2.50%**	2.75%
Rate of increase in health care cost trend[4]	**–**	—	**4.40%**	4.40%

[2] The Company follows the cash basis of accounting. During 2005, pension costs of $83 million (2004 - $81 million) were attributed to labour, of which $23 million (2004 - $22 million) was charged to operations, $32 million (2004 - $31 million) was capitalized as part of the cost of fixed assets, and $28 million (2004- $28 million) was attributed to a regulatory asset.

[3] 8.47% in 2005 grading down to 4.40% per annum in and after 2014 (2004 – 9.00% in 2004 grading down to 4.40% per annum in and after 2014).

[4] 7.87% in 2006 grading down to 4.40% per annum in and after 2014 (2004 – 8.47% in 2004 grading down to 4.40% per annum in and after 2014).

13. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	2005	2004
Environmental liabilities, January 1	**89**	83
Interest accretion	**5**	5
Expenditures	**(14)**	(15)
Revaluation adjustment *(Note 9)*	**(1)**	16
Environmental liabilities, December 31	**79**	89
Less: current portion	**(15)**	(15)
	64	74

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2005 and in total thereafter are as follows: 2006 - $15 million; 2007 - $14 million; 2008 - $12 million; 2009 - $10 million; 2010 - $9 million; and thereafter - $40 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

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 $25.00 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 2005, preferred dividends in the amount of $18 million (2004 - $18 million) and common dividends in the amount of $273 million (2004 - $247 million) were declared.

14. SHARE CAPITAL (continued)

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 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 uniform transmission rates approved by the OEB. Transmission revenue for 2005 includes $1,276 million (2004 - $1,228 million) related to these services.

Hydro One received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2005 includes $21 million (2004 - $21 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2005 includes $127 million related to this program. In 2004, the Company also received $127 million for rural rate protection, of which $1 million was paid to LDCs in respect of annexation agreements.

In 2005, Hydro One purchased power in the amount of $2,095 million (2004 - $1,951 million) from the IESO administered electricity market and $36 million (2004 - $36 million) from OPG.

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 2005, Hydro One incurred $7 million (2004 - $10 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 $11 million (2004 - $11 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 $1 million in each of 2005 and 2004.

The provision for payments in lieu of corporate income taxes was paid or payable to OEFC and dividends were paid or payable to the Province (see Note 2).

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)	2005	2004
Accounts receivable	**116**	120
Accounts payable and accrued charges	**(263)**	(247)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $213 million (2004 - $200 million).

16. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the consolidated statements of cash flows, "cash and cash equivalents" refers to the balance sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2005	2004
Accounts receivable decrease (increase)	85	(91)
Materials and supplies increase	(9)	(2)
Accounts payable and accrued charges increase	70	10
Accrued interest (decrease) increase	(1)	6
Long-term accounts payable and accrued charges decrease	(1)	(9)
Employee future benefits other than pension increase	62	57
Other	(12)	(4)
	194	(33)
Supplementary information:		
Interest paid	300	285
Payments in lieu of corporate income taxes	210	207

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 an adverse effect on the Company's consolidated financial position, results of operations or cash flows.

As a result of Hydro One's acquisition of certain transmission, distribution and energy services assets, liabilities, rights and obligations of Ontario Hydro, Hydro One has succeeded Ontario Hydro as a party in a number of legal proceedings. On September 1, 1995, Torcom Communications Inc. (Torcom) named Ontario Hydro as one of several defendants in a suit seeking damages of $150 million, as well as specific performance of certain agreements and interim injunctive relief. Torcom had sought to purchase certain telecommunication devices belonging to a bankrupt company from the court-appointed receiver. The devices had been installed on Ontario Hydro property under licence to the original owner. Torcom claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995, when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not yet served a statement of defence. Hydro One believes that there are strong defences to the plaintiff's claims against Ontario Hydro and that it is unlikely that the outcome of the litigation will have a material adverse effect on its business, results of operations, financial position or prospects. Torcom has not proceeded with this claim for almost ten years.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG

17. CONTINGENCIES (continued)

and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty, and compensation for costs incurred in the course of prior negotiations of band grievances with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. This case was consolidated 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 Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its business, results of operations, financial position or prospects.

Transfer of Assets

On April 1, 1999, in connection with the acquisition of its operations, Hydro One acquired and assumed the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses, except for certain transmission, distribution and other assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Transfer of title to these assets did not occur because authorizations originally granted by the Minister of Indian Affairs and Northern Development (Canada) for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. Hydro One manages these assets, which are currently owned by OEFC.

Hydro One has commenced negotiations with the relevant Indian bands and bodies to obtain the authorizations and consents necessary to complete the transfer of these transmission, distribution and other assets. Hydro One cannot predict the aggregate amount that it may have to pay to obtain the required authorizations and consents. Hydro One expects to pay more than $850,000 per year, which was the amount previously paid to these Indian bands and bodies by Ontario Hydro and which was the total amount of allowed costs in the transitional rate orders. If, after taking all reasonable steps, Hydro One cannot otherwise obtain the authorizations and consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. Alternatively, Hydro One 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. In such cases, Hydro One would apply to recover these costs in future rate orders.

18. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. 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 ten-year period. The initial service level price ranges between $90 million and $130 million per year, 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, 2005, and in total thereafter are as follows: 2006 - $110 million; 2007 - $108 million, 2008 - $97 million; 2009 - $93 million; 2010 - $90 million; and thereafter - $102 million.

Additionally, the outsourcing agreement with Inergi includes a risk sharing agreement involving either Hydro One or Inergi making a payment related to a past imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement was settled based on data available on December 31, 2004, reflecting economic factors and pension fund rates of return. Hydro One is required to pay Inergi approximately $17 million equally over the next two years.

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. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of the bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2005, the Company provided prudential support, using a combination of bank letters of credit of $21 million (2004 - $33 million) and parental guarantees of $275 million (2004 - $275 million).

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, 2005, Hydro One had bank letters of credit of $82 million (2004 - $80 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, 2005 and in total thereafter are as follows: 2006 - $5 million; 2007 - $4 million; 2008 - $4 million; 2009 - $4 million; 2010 - $nil; and thereafter - $nil.

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. Hydro One is currently in the process of assessing its strategy with respect to these operations.

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
2005				
Segment profit				
Revenues	**1,310**	**3,085**	**21**	**4,416**
Purchased power	**–**	**2,131**	**–**	**2,131**
Operation, maintenance and administration	**353**	**413**	**26**	**792**
Depreciation and amortization	**246**	**236**	**5**	**487**
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	**711**	**305**	**(10)**	**1,006**
Financing charges				**325**
Income before provision for payments in lieu of corporate income taxes				**681**
Capital expenditures	**349**	**338**	**4**	**691**
2004				
Segment profit				
Revenues	1,262	2,874	17	4,153
Purchased power	—	1,987	—	1,987
Operation, maintenance and administration	356	392	23	771
Depreciation and amortization	241	234	5	480
Income (loss) before financing charges, provision for payments in lieu of corporate income taxes and regulatory recovery	665	261	(11)	915
Regulatory recovery				91
Income before financing charges and provision for payments in lieu of corporate income taxes				1,006
Financing charges				331
Income before provision for payments in lieu of corporate income taxes				675
Capital expenditures	432	288	7	727

December 31 (Canadian dollars in millions)	2005	2004
Total assets		
Transmission	**6,832**	6,785
Distribution	**4,925**	4,845
Other	**92**	95
	11,849	11,725

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

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	2005	2004	2003	2002	2001
Statement of operations data					
Revenues					
Transmission	**1,310**	1,262	1,298	1,317	1,259
Distribution	**3,085**	2,874	2,734	2,682	2,158
Other	**21**	17	26	32	49
	4,416	4,153	4,058	4,031	3,466
Costs					
Purchased power	**2,131**	1,987	1,872	1,858	1,267
Operation, maintenance and administration[1]	**792**	771	795	832	824
Depreciation and amortization	**487**	480	454	411	384
	3,410	3,238	3,121	3,101	2,475
Regulatory recovery[2]	**–**	91	—	—	—
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,006**	1,006	937	930	991
Financing charges	**325**	331	348	353	350
Income before provision for payments in lieu of corporate income taxes	**681**	675	589	577	641
Provision for payments in lieu of corporate income taxes	**198**	177	193	233	267
Net income	**483**	498	396	344	374
Basic and fully diluted earnings per common share *(Canadian dollars)*	**4,652**	4,798	3,779	3,258	3,562
December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**6,832**	6,785	6,589	6,638	6,693
Distribution	**4,925**	4,845	4,623	4,694	4,416
Other	**92**	95	94	90	122
Total assets	**11,849**	11,725	11,306	11,422	11,231
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,341**	1,262	1,192	1,894	1,625
Long-term debt	**4,466**	4,613	4,539	3,938	4,079
Other long-term liabilities	**1,326**	1,326	1,284	1,451	1,533
Shareholder's equity					
Share capital	**3,637**	3,637	3,637	3,637	3,637
Retained earnings	**1,079**	887	654	502	357
Total liabilities and shareholder's equity	**11,849**	11,725	11,306	11,422	11,231

Year ended December 31 (Canadian dollars in millions)	2005	2004	2003	2002	2001
Other financial data					
Capital expenditures					
Transmission	**349**	432	289	260	274
Distribution[3]	**338**	288	292	286	247
Other	**4**	7	16	24	45
Total capital expenditures	**691**	727	597	570	566
Ratios					
Net asset coverage on long-term debt[4]	**1.93**	1.88	1.86	1.90	1.88
Earnings coverage ratio[5]	**2.69**	2.70	2.43	2.35	2.53
Operating statistics					
Transmission					
Units transmitted *(TWh)*[6]	**157.0**	153.4	151.7	153.2	146.9
Ontario 20-minute system peak demand *(MW)*[6]	**26,219**	25,204	24,849	25,629	25,269
Ontario 60-minute system peak demand *(MW)*[6]	**26,160**	24,979	24,753	25,414	25,239
Total transmission lines *(circuit-kilometres)*	**28,547**	28,643	28,621	28,492	28,387
Distribution					
Units distributed to Hydro One customers *(TWh)*[6]	**29.7**	28.5	27.9	27.1	21.3
Units distributed through Hydro One lines *(TWh)*[6,7]	**45.6**	44.8	44.7	45.1	41.3
Total distribution lines *(circuit-kilometres)*	**122,118**	121,736	121,285	120,767	120,448
Customers	**1,273,768**	1,258,925	1,238,748	1,219,614	1,193,089
Total regular employees	**4,189**	4,118	3,967	3,933	4,815

[1] Operation, maintenance and administration costs for 2002 included a charge of $25 million for a staff reduction program.

[2] 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.

[3] Capital expenditures exclude $468 million in 2001 associated with acquisitions of LDCs.

[4] 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).

[5] 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.

[6] System related statistics include preliminary figures for December.

[7] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO. Prior to Open Access in 2002, these consumers purchased power directly from the predecessor of OPG.

SENIOR MANAGEMENT TEAM

Tom Parkinson
President and
Chief Executive Officer

Laura Formusa
General Counsel and
Secretary

Geoff Ogram
Vice-president,
Strategy and Development

Wayne Smith
Vice-president,
Grid Operations

Steve Dorey
Vice-president,
External Relations

Peter Gregg
Vice-president, Executive office
and Corporate Communications

Nairn McQueen
Vice-president,
Engineering and
Construction Services

Rick Kellestine
Vice-president,
Culture

Myles D'Arcey
Senior Vice-president,
Customer Operations

Beth Summers
Chief Financial Officer

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

Tom Goldie
Senior Vice-president,
Corporate Services

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SNC–Lavalin Group Inc.

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Kenneth D. Taylor

Chair, Taylor and Ryan Inc.

Blake Wallace, Q.C.

Vice President and Director,
Murray & Company

W. Geoffrey Beattie

President, The Woodbridge
Company Limited

Resigned November 10, 2005

Dr. Murray B. Frum

Chair and CEO,
Frum Development Group

Resigned September 29, 2005

Adam Zimmerman

Coporate Director

Resigned July 18, 2005

BOARD COMMITTEES

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 four times in 2005.

Members: Eileen Mercier, *Chair*. Murray Elston, Walter Murray, Kathleen O'Neill, Douglas Speers

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 mandates of 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 four times in 2005.

Members: Blake Wallace, *Chair*. Rita Burak, Eileen Mercier, Hon. Bob Rae

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 significant impact on us. The committee met seven times in 2005.

Members: Hon. Bob Rae, *Chair*. Walter Murray, Kathleen O'Neill, Blake Wallace

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, reviews the Company's proposals for rate applications and reviews compliance actions and reports. The committee met five times in 2005.

Members: Murray Elston, *Chair*. Sami Bébawi, Don MacKinnon, Kenneth Taylor, Blake Wallace

Health and Safety Committee

The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs, compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2005.

Members: Don MacKinnon, *Chair*. Sami Bébawi, Douglas Speers, Kenneth Taylor

COPORATE INFORMATION

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Business accounts: 1-877-447-4412

Auditors

Ernst & Young LLP

Electricity Highway
Transmission towers reliably deliver electricity all across the province and ensure that businesses, families and communities have the power they need to prosper.

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