DOING THE EXCEPTIONAL – WITHOUT EXCEPTION

ANNUAL REPORT 2004 >

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 LETS ELECTRICITY 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.

WE WORK SAFELY AND KEEP YOU SAFE.
WE SERVE OUR CUSTOMERS WITH RESPECT.
WE FOCUS ON RELIABILITY.
WE DO OUR JOBS WITH PRIDE.
WE DELIVER VALUE TO OUR SHAREHOLDER.

TABLE OF CONTENTS >

HYDRO ONE AT A GLANCE >

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.

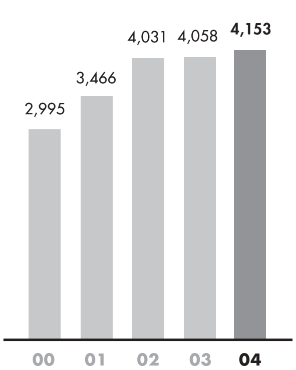
Hydro One Networks Inc. represents the significant majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

ACCOMPLISHMENTS IN 2004 >

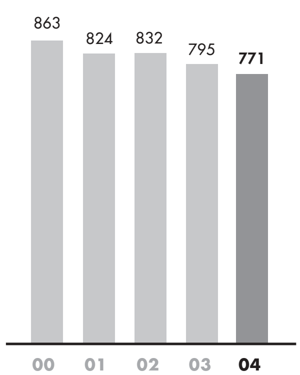
- Continued to make safety our top priority in 2004 with a goal of eliminating serious injuries by 2006. Since 1999 our lost-time incident frequency rate has dropped by 60 per cent.
- Continued to work with our customers and with many proponents of new generating facilities in Ontario in support of the provincial government's initiatives to increase Ontario's supply of electricity. We will continue to support this important initiative in 2005.
- Made significant progress in improving or maintaining customer satisfaction across all of our customer segments.
- Officially opened our state-of-the-art Ontario Grid Control Centre in Barrie. Completed on time and under budget, the centre puts world-class transmission and distribution grid control technology in the hands of our highly trained workers.
- Strong financial performance: earned $407 million before a one-time regulatory recovery of $91 million, for a total of $498 million. Our financial metrics continue to support our credit rating target.
- Invested $1.5 billion primarily in upgrades, construction and maintenance of our electricity delivery network to ensure continued reliability and to meet increased demand for electricity.

KEY CREDIT STRENGTHS >

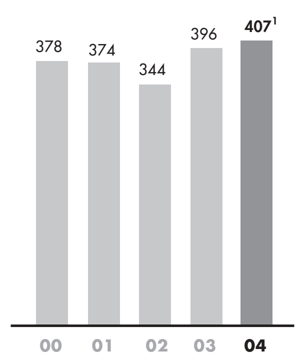
- Hydro One owns and operates the largest electricity delivery system in Ontario and one of the largest in North America
- Experienced management team focused on the core electricity delivery business
- Highly skilled and experienced workforce with first-class operating systems
- Recognized industry 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



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)

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

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.

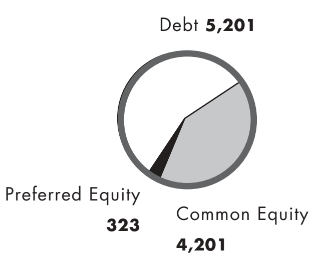
Hydro One Telecom Inc. markets our fibre optic capacity to business customers and represents less than 1 per cent of our total assets.

CONSOLIDATED FINANCIAL HIGHLIGHTS

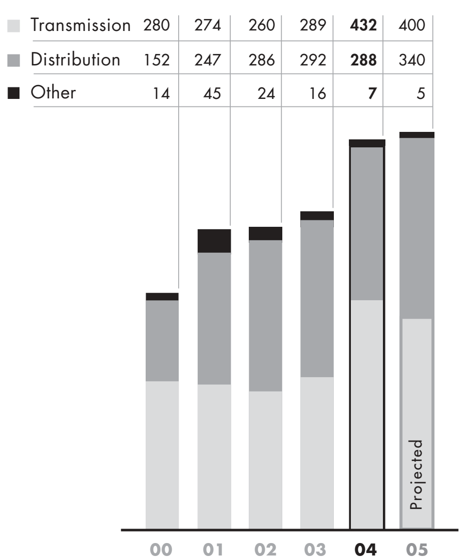
Year ended December 31 (Canadian dollars in millions)	**2004**	2003	$ Change	% Change
Revenues	**4,153**	4,058	95	2
Purchased power	**1,987**	1,872	115	6
Operating costs	**1,251**	1,249	2	—
Net income	**407**[2]	396	11	3
Net cash from operations	**911**	1,032	(121)	(12)

STATISTICS

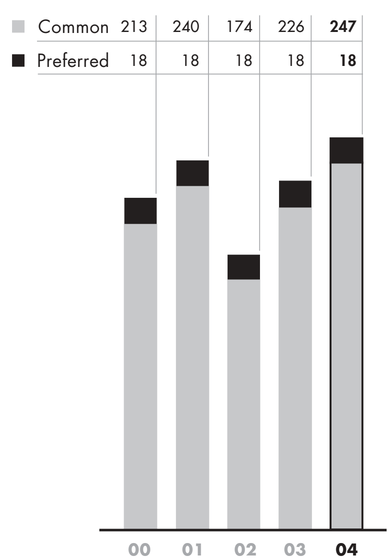
Transmission – units transmitted (TWh)[3]	**153.4**	151.7	1.7	1
Distribution – units distributed to Hydro One customers (TWh)[2]	**28.5**	27.9	0.6	2



Capital Structure
December 31, 2004
(Cdn $ millions)



Capital Expenditure
Year ended December 31
(Cdn $ millions)



Dividends[4]
Year ended December 31
(Cdn $ millions)

[2] Based on net income of $498 million, which includes a one-time regulatory recovery of $91 million, the change over 2003 is $102 million, or 26%.
[3] System related statistics include preliminary figures for December.
[4] Common dividends for 2000 do not include $13 million in preferred dividends and $158 million declared in respect of the first nine months of 1999.

MESSAGE FROM THE CHAIR

In 2004, Hydro One continued to successfully operate and maintain Ontario's electricity transmission system and the province's largest distribution system. Hydro One served its customers, shareholders and investors well and reliably delivered the electricity that Ontario depends upon.

As the Board of Directors of Ontario's electricity transmission and largest distribution company, we are charged with ensuring the company's transparency and accountability. The good governance of Hydro One is essential to our shareholder, the Province of Ontario, our investors and the people of Ontario. Good governance requires the Board to ensure that Hydro One remains focused on maintaining a strong, fiscally responsible and reliable electricity system for Ontario that meets the province's present needs and is ready for the future. The current Board is effective and experienced, and I would like to thank them for their contribution to Hydro One's continued success in 2004.

The Board of Directors continues its commitment to maintaining system reliability and readying Ontario's electricity system for the future. The Company made significant progress towards strengthening our transmission and distribution network by investing $1.5 billion, primarily in upgrades, construction and maintenance. Continued investment is planned for 2005 and beyond to ensure we can deliver electricity from new generation points to where it is needed. A safe, secure future for Ontario's electricity delivery system is vital to the province's well being.

With the passage of Bill 100, the government has taken steps to bring increased stability to the electricity industry. The bill restructures the electricity sector and responsibilities for long-term planning and price setting have been clarified. Hydro One can now work even more effectively to ensure electricity is delivered to where it is needed to meet Ontario's needs.

Hydro One achieved a strong financial performance with net income of $498 million, a 26% increase from 2003. The increase is primarily due to Hydro One's successful application to the Ontario Energy Board to recover regulatory asset amounts previously charged to operations. Excluding the one-time regulatory recovery, net income was $407 million, or a 3% increase from 2003.

These results reflect Hydro One's continued commitment to prudent management of this important provincial asset. Hydro One paid its shareholder, the Province of Ontario, dividends of $265 million and it also recorded $177 million of income taxes, which help reduce the legacy-stranded debt held by the Province. In 2005, the Board sees continued strong, stable financial performance.

On behalf of the Board of Directors I would like to thank Hydro One's management and employees for their commitment to excellence. Together we will continue to serve our customers, our shareholder and our investors with pride, integrity and professionalism.

Rita Burak
Chair
Hydro One Inc.

MESSAGE FROM THE PRESIDENT

When you work with great people, sometimes you forget just how good they really are. This fall Ontario was blessed with a relatively mild storm season. By contrast, Florida was hit hard with four hurricanes in a six-week period. Some citizens were without power for more than two weeks. My counterpart at Florida Power and Light asked if we could lend them a hand. We responded by sending two groups of line maintainers, almost 500 workers in total, to help get the lights back on. And like they do every day in Ontario, Hydro One's employees focused on the task and got the job done right. The people of Florida called them heroes. Florida Power and Light said we must have hand picked our best employees. But we didn't. We could have sent any of our line maintainers. The men and women of Hydro One who I work with all show that same pride, passion and commitment in serving Ontario every single day.

And the proof of that commitment is in our performance. 2004 was a good year for our company. Hydro One earned net income of $407 million plus a one-time regulatory recovery of $91 million for a total of $498 million. We paid our shareholder, the Province of Ontario a healthy dividend. Our stable financial results this year were consistent with our expectations. We remain committed to earning a healthy return for our shareholder while ensuring that Ontario's electricity delivery system will continue to perform at an optimal level long into the future.

In August, we opened the world-class Ontario Grid Control Centre in Barrie, Ontario on time and on budget. This state-of-the-art, secure facility puts the most sophisticated grid monitoring and management technology in the hands of Hydro One's highly trained staff. The $118 million investment gives us the capability to operate and oversee Ontario's grid from a single location. This makes both operational and financial sense. It puts all of our controllers in the same facility and eliminates the need for multiple regional control centres. This improves our ability to react to emergencies and coordinate maintenance efforts.

This year we invested more than $1.5 billion primarily in upgrading, maintaining and reinforcing our electricity delivery network. This work included connecting new sources of generation to Ontario's electricity grid. Hydro One is working closely with proponents of new generation to make sure we are able to deliver new sources of electricity to our customers.

Making Hydro One an industry leader in worker safety is my top priority. In 2004, we focused on eliminating injuries and incidents associated with our higher risk activities. We will systematically eliminate all electrical contacts, serious motor vehicle accidents, falls and other incidents where serious injuries can occur. And we've made great strides toward this goal.

But new policies and procedures can only get us so far. The way to achieve our goal of zero serious injuries is all about making safety personal. It's not just about how we plan and perform our work, it's about our belief in and commitment to ensuring each and every one of us goes home safely at the end of each work day. Anything less is simply unacceptable.

WE'RE WORKING WITH THE COMPANIES, COMMUNITIES AND HOUSEHOLDS IN ONTARIO TO PROVIDE EVEN BETTER SERVICE IN THE FUTURE >>

Our efforts to better serve our customers are paying off. In the past two years we re-organized the way we work with our large industrial customers and put in a system to measure how well we keep our promises. We improved customer satisfaction in our large customer segment by more than 20%, to 73%. The satisfaction level of our residential customers remains high. We continue to work with the companies, the communities and the households we serve to provide even better service in the future.

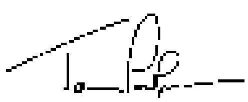
In the coming decade, connecting new generation to meet Ontario's ever-growing need for electricity will demand the best of Hydro One. My team and I are planning for this future by constantly examining our delivery systems and working with our customers to forecast their future needs and the transmission solutions to meet them. Some of these projects are straightforward line upgrades while others will require years to plan and complete. Investment in and strategic planning for the future of Ontario's electricity grid, and indeed the entire electricity sector, must continue. While significant progress has been made, we need to continue to find ways to complete these projects more quickly and to streamline the approval process to ensure we continue to meet the electricity

A SHINING LIGHT IN FLORIDA >

Florida residents express their gratitude to Hydro One crews who helped restore power to hurricane–stricken communities.

needs of Ontario's households, communities and businesses. We will cooperate closely with our partners in the electricity sector and our shareholder, the Province of Ontario. Hydro One's experience and expertise is a resource that Ontario can continue to count on.

I'd like to thank the workers of Hydro One for their efforts and steadfastness in 2004. Their commitment to our strategic direction shows in our results and in the satisfaction of our customers. I'm proud of the great work all of our people do every day of the year in Ontario. I look forward to further steps in our journey as we continue to provide the province with an electricity delivery system that is among the best in the world.



Tom Parkinson
President and Chief Executive Officer

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"I can't tell you how relieved we were to see your guys, after nine days without power," said Robert Kaidy of Stuart Florida. "Their professional, courteous, and helpful style gave us confidence and hope."

Florida is a long way from Ontario but when the state was hit hard by the worst hurricane season in a dozen years, Florida Light and Power asked for Hydro One's expertise under the North American Assistance Agreement.

September 9, a convoy of 130 trucks and 270 workers pointed themselves south to help out in the aftermath of Hurricane Charley. Just after they returned home 15 days later, Florida Power and Light called again. On September 27, a second convoy headed down to help out some of the same communities that the first group had aided.

"The crew from Hydro One were the hardest working and we were honored in Stuart, Florida, to have them. I hope you will pass on the sincere and heartfelt thanks from our family to all of the hard working men and women who made your success in Florida possible," Kaidy wrote.

Every day all of our people bring that same sense of pride and commitment to the job they do for the people of Ontario.

Above
In 2004, our crews across the province completed a significant amount of work on our low-voltage distribution system. This network of 1.6 million poles and more than 123,000 circuit-kilometres of distribution lines stretches across Ontario. In 2004, Hydro One invested $680 million in upgrading, maintaining and reinforcing our distribution network. We know our customers count on us to take care of the system that delivers electricity to their homes and businesses.

Right
Hydro One's fleet includes trucks, snowmobiles, all-terrain vehicles, boats and helicopters that allow us to cover our 640,000 sq km of service territory.

OUR GOAL IS TO BE THE BEST TRANSMISSION AND DISTRIBUTION COMPANY IN NORTH AMERICA, BAR NONE >>

While delivering electricity to all of Ontario is a complex task, our approach to success is simple. We focus on our core tasks. We work safely. We put the best technology in the hands of the best people. We operate Ontario's electricity grid with intelligence, integrity and pride. We provide our customers with the electricity they need. We deliver stable results to our shareholder and investors.

To our customers, large and small, supply reliability is the bottom line. They depend upon a constant supply of electricity to run their homes, businesses and lives. In 2004, we delivered that electricity more reliably than ever before. We improved our transmission system reliability over 2003 levels and out-performed our 2004 target. Largely due to severe weather conditions in December, we missed our distribution targets. But those winter storms aside, in 2004 we improved our performance in customer satisfaction and service across the board.

To improve performance, Hydro One took a number of important steps during the year. We adjusted crew scheduling to allow faster restoration response to unplanned outages. By increasing the flexibility of our crews, they are now able to get on the road and on the scene more rapidly. This minimizes the length of unplanned outages in our distribution system and helps us help our customers more quickly.

In 2004, Hydro One staff committed themselves to improving communication with our customers, understanding their needs and keeping our promises. We have taken concrete steps in the last two years to get to know our customers better by meeting with them more regularly. We also introduced a commitment tracking system to make sure we keep our word. Since this system was introduced in 2003, we have steadily improved customer service. And it shows. This year, we substantially improved our large-sized customer satisfaction survey results from 52% in 2003 levels to 73% this year. Satisfaction levels of our distribution customers are high and we are committed to continuous improvement. Building on the momentum achieved in the past two years, we will continue to focus on improving the level of satisfaction of all our customers.

TAKING CARE OF OUR ASSETS

In 2004, Hydro One focused on strengthening our transmission and distribution network by investing $1.5 billion primarily in upgrades, construction and maintenance.

Hydro One made significant capital investments in our transmission system, $432 million in total. Much of the work undertaken this year was in support of the provincial government's commitment to phase out coal-fired generation in Ontario. To maintain reliable delivery of electricity to the Greater Toronto Area, Hydro One began construction of the new Parkway transformer station. It's been more than a decade since a station of this magnitude has been built in Ontario. Through value-based engineering and smart procurement strategies, costs for the Parkway transformer station are expected to be 20 per cent less than equivalent stations built 15 years ago. Across the province, from Windsor to Ottawa and north to Pickle Lake, other work is under way to make sure our system is ready as Ontario's electricity needs evolve.

Capital investments in Hydro One's lower-voltage distribution facilities amounted to $288 million in 2004. This spending is part of our planned, long-term reinvestment in a reliable electricity system for the 1.3 million customers served by our distribution network. Through our digital asset management program we

HIGH-TECH SNIFFER SYSTEM SEEKS LEAKS >

Hydro One's Steve Haddock and Kinectrics Senior Physicist Hugh Morrison flow tracer fluid into one of Hydro One's underground cables near Lakeshore Boulevard in Toronto.

have tested 247,000 poles across the province and stepped up replacing those at the end of their service life. By digitally registering every pole and using Global Positioning System (GPS) technology we now have a much better picture of the condition of our 1.6 million poles. This means we can get the most out of the money we spend on them, replacing only what needs to be replaced. This asset management model is also being successfully used to monitor other equipment like transformers and stations.

With a service area of more than 640,000 square kilometres, our transmission and distribution lines pass through some of Ontario's most remote and rugged terrain. This means our forestry crews are busy year-round keeping the lines clear. This year, Hydro One trimmed trees and cleared brush along 10,000 km of distribution line. We also trimmed trees along 2,600 km of transmission line and cleared more than 10,000 hectares of brush along transmission rights-of-way. This large-scale, tactical forestry program is designed to get Ontario on to a well-defined, seven-year clearing cycle for transmission lines and an eight-year clearing cycle for distribution lines that we will then maintain. This work will help us improve system reliability and cut down on the number of unplanned outages caused by trees down on the lines.

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An oil leak in an underground transmission cable used to mean digging long trenches and interrupting service while crews located elusive leaks.

Using the latest technology, Hydro One has greatly improved our leak finding efficiency.

Hydro One's team now uses perfluorocarbon tracer (PFT) fluids to track down leaks. Perfecting this technology required a significant amount of research, development and testing that resulted in a unique development for the industry and has also helped Hydro One realize considerable savings.

Leaks occur for a number of reasons – corrosion of the pipe, shifting of earth – and must be located and fixed quickly to reduce effects on the environment and minimize soil pollution and system downtime.

When the meter indicates a cable is losing pressure, cable fluid mixed with PFT fluid is added to the system. Once the tracer fluid is distributed throughout the cable – a few hours or a few days, depending on the cable length – we start searching the line. Using high-tech sensing equipment, we measure the air along the cable for the presence of PFT. Once we find the "hotspot", digging and repairs can commence.

"The PFT system can locate leaks without de-energizing the line or requiring excavation," says Steve Haddock, team leader, asset management.

Above
Hydro One started the Customer Advisory Board (CAB) in 2003 to give customers a voice at the highest level of the company. Several times a year the CAB brings together a representative group of customers, including transmission and distribution customers as well as local distribution companies to hear what they have to say.

Mary Ellen Richardson, President, Association of Major Power Consumers of Ontario (above), sits on the CAB.

"The formula is a good one. It has a protocol, it's member led and it's balanced between representatives from different customer groups."

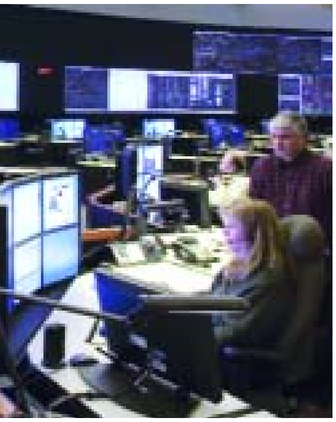
"We've heard a lot of talk from the company in the last two years about becoming more customer focused and it's more than words. Hydro One is a pragmatic company that is becoming more focused on customer needs."

Right
This year we transferred operational control of our transmission and distribution systems to our new Ontario Grid Control Centre in Barrie. This state-of-the-art facility gathers together all of our transmission and distribution control systems and operating staff into one place.

GETTING THE JOB DONE SAFELY

WORKING SAFELY IS OUR TOP PRIORITY. WE'RE COMMITED TO ELIMINATING ALL SERIOUS INJURIES BY 2006 >>

In our business, mistakes can be fatal. Our workers perform highly skilled and specialized jobs on electrically charged equipment, often at height and in difficult weather conditions. That's why working safely is Hydro One's top priority. We have set aggressive targets for safety performance to focus every member of our team on working safely, without exception. Our efforts are aimed at eliminating all serious injuries by 2006 caused by our higher risk activities. We will prevent all electrical incidents and motor vehicle accidents where there is a high potential for serious injuries. When it comes to safety behind the wheel, employees will soon undergo in-cab assessments and receive training from one of our safe driving experts. The frequency of incidents where serious injuries occurred in 2004 was lower than in the previous year. Since 1999, our lost-time accident frequency rate has dropped by approximately 60 per cent. The majority of our 2004 lost-time incidents were related to strain and exertion rather than high-risk activities involving electricity or gravity. While this places us in the top quartile of Canadian transmission and distribution companies, we want to set a new industry standard.



To achieve this, we will continue to put safety first. In 2004, we introduced a coaching and mentoring program to give more employees the opportunity to work as safety officers for periods of time. Power line maintainers were assigned full-time developmental opportunities within the Safety Department. As both safety and power system experts, they observed work crews across the province to ensure compliance with the safety rules. The reassigned workers continually learn from the crews they work with and share the knowledge with the rest of the company. Experienced field staff – intimately familiar with the work, its hazards and specific challenges – are leading the charge towards zero serious injuries.

To prevent injuries, we introduced new arc-resistant protective clothing for all staff who work in the electrical environment. In the field, forestry staff developed advanced rigging techniques to more safely clear trees from transmission and distribution lines, both in emergency and maintenance situations. These new rigging techniques enable Hydro One workers to work more safely, prevent wear and tear on their bodies and improve efficiency. We are sharing these methods with other utilities to assist them in boosting their own safety performance and operational efficiency.

READY TO CONNECT NEW SUPPLY

In 2004, Hydro One supported the development of new generation in Ontario by working with and connecting new generators. This summer, we connected the natural-gas fired Brighton Beach generating station, adding more than 600 MW to Ontario's generating capacity with a single project.

The provincial government's Request for Proposals for new clean generation, renewable generation and conservation programs unleashed a flurry of work for our generation connections group. Hydro One worked with generation proponents throughout the province to give them the information they needed, such as connection cost estimates, to enable them to properly submit their proposals to the government.

Hydro One released its 10-year plan for developing its transmission network to keep pace with Ontario's need for electricity delivery. The plan focuses on how to maintain reliable supply to growing communities like the Greater Toronto Area, Ottawa and Windsor. It takes on the challenge of relieving transmission bottlenecks that prevent Hydro One from delivering all electricity from supply to load and it explores interconnections and proactive system reinforcement to ensure new generation sources can reach Ontario's electricity consumers.

GETTING THE MOST FROM OUR SYSTEM >

Charles and Judy Tedder save money and help the environment by participating in one of Hydro One's electricity conservation pilot programs.

Some of the projects identified in the document are already underway. We are already working to relieve congestion between the Niagara peninsula and the rest of southern Ontario. We have completed the Ministry of Environment's environmental assessment process and have approval for an underground cable project in downtown Toronto. This project was approved by the Ontario Energy Board on March 11, 2005. This project supplies much needed supply flexibility to Toronto's downtown core. We have also begun the consultation and approval process for a new station in southern Simcoe County to improve supply to that area.

In 2003, Ontario and much of the northeastern United States experienced an electrical blackout affecting more than 50 million people. Throughout 2004, Hydro One was a key player in the investigation as to how the blackout developed and implemented measures to prevent this from happening again. While the causes of the blackout were rooted in Ohio, Hydro One's participation in this investigation through data collection and expert analysis strengthens our own system and grows our understanding of business best practices.

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Hydro One is working with our customers to help use Ontario's available electricity more wisely.

The Tedder family of Zephyr, Ontario, is taking part in our Load Control Pilot program. Along with hundreds of other customers from the Kingston, Newmarket, Simcoe and Brampton areas, they are allowing Hydro One to remotely shut off equipment to help take stress off the electricity system during peak load.

"Hydro One called us and told us about the program we thought it sounded like a good idea. If it helps us use less electricity, we're all for it," Charles Tedder said. "We've noticed that our bill is down a bit and that's never a bad thing."

The Tedder's hot water tank is connected to a pager that receives a signal telling it to shut down for periods throughout the day.

"If you don't start saving electricity somewhere, we're not going to have it when we really need it," said Judy Tedder.

In a second pilot project, Hydro One installed a power cost monitor so customers can track exactly how much electricity they're using and what it costs them. It helps consumers identify their high-use periods and appliances that are energy hogs.

Above
Bill Chant, Lines Superintendent, brings 36 years of experience to taking care of Ontario's transmission and largest distribution system.

Right
Forestry apprentices Jason Swant (front) and Frank Groves train in Cloyne to use Hydro One's advanced rigging system. Since 2003, Hydro One's lines, forestry and stations groups have focused on providing young workers with skills and knowledge to become the next generation of safe and productive workers.

PASSING THE TORCH

OPERATING AND MAINTAINING ONE OF NORTH AMERICA'S LARGEST ELECTRICITY TRANSMISSION AND DISTRIBUTION NETWORKS DEMANDS A SKILLED, PROFESSIONAL WORKFORCE >>

How do you replace someone like supervisor Bill Chant? Every day when he comes to work, he not only brings 36 years of experience, he brings commitment, dedication and passion.

"The work we do is important. We work hard to make sure electricity is there when people need it and I think that's a pretty good way to make a living," Chant says.

Some time in the near future, Bill will retire. And he's not alone. By 2008, 25 per cent of Hydro One employees will be eligible for retirement and 60 per cent of energy industry workers are eligible to retire by 2010.

Operating and maintaining one of North America's largest electricity transmission and distribution networks demands a skilled, professional workforce.

Replacing these people and building on their accomplishments demands careful consideration about how to best fill these very large shoes.

Hydro One is preparing for the future by hiring apprentices in lines and forestry so that there will be a skilled workforce ready to take care of our system. We've also invested in co-op power engineering programs at the University of Western Ontario and the University of Waterloo.

While we can't replace 36 years of experience, we can make sure someone is there to pass the torch to.

IN YOUR COMMUNITY

Hydro One employees are members of communities across the province and make meaningful contributions to local sports, social service organizations and community groups. In 2004, our employees and pensioners raised more than $740,000 for charities in their own communities.

Hydro One sponsors several programs, but is especially proud of the work we do with the Passport to Safety program. This gives Ontario youth access to safety education developed by Canadian health and safety curriculum experts. Successful participants earn a passport that says they have basic awareness of health and safety. Participants can then add more credits in areas such as first-aid, babysitting, water-safety and snowmobile safety. This program gives Ontario youth a head start on understanding workplace safety.

By putting all of our energy into delivering the electricity that Ontario needs, we are succeeding. By bringing the latest technology and best practices to bear on our tradition of operational excellence, we are becoming a better, stronger, safer company every year. We will continue to serve Ontario with pride, skill and dedication.

HARD TO REACH SPOTS >

Pickle Lake Mayor Roy Hoffman says reliability has noticeably improved after a $5.4-million transmission line upgrade to his community in 2004.

HYDRO ONE EMPLOYEES TAKE PRIDE IN SUPPORTING THE COMMUNITIES WHERE WE LIVE, WORK AND SERVE, WITH A SPECIAL EMPHASIS ON SAFETY >>

Through our corporate sponsorship program, Hydro One continues to help develop the Ross Tilley Burn Unit at Sunnybrook and Women's Hospital in Toronto. Working together with the NORTH Network and Telehealth Ontario, Hydro One has made the best electrical contact burn doctors available to communities across Ontario. Doctors across the province now have the best information available with a simple phone call.

Passport to Safety
Setting the Standard

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Pickle Lake is 521 kilometres of rough highway from Thunder Bay and like much of Ontario's rugged north, it's wild, beautiful and unforgiving.

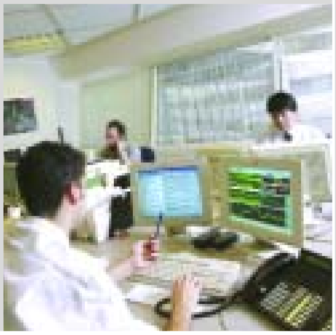
"If the road is shut down or if the weather is too bad to fly, we can just go without for a while," says Mayor Roy Hoffman. "But if we lose our electricity, it gets serious very quickly."

In 2002, the transmission line connecting Pickle Lake to the generation station in Ear Falls began to show signs of wear that outpaced the rate of repair. The community of 400 living on the edge of Pickle Lake started to notice that electricity was failing more often.

"We let Hydro One know we were having trouble, they investigated the problems with the line and stepped up the plan for upgrading."

In 2004, 180 structures were replaced and in 2005 Hydro One plans on replacing 121 structures. The line runs through rugged, swampy country, and upgrading means flying in replacements and crews, working in extreme cold and contending with voracious mosquitoes and black flies. Since the line is Pickle Lake's sole source of power, all of the work has to be done with the power left on.

"Hydro One has done a good job by this community," Hoffman says. "No one is talking about outages, so it's safe to say they're not a problem."



FINANCIAL REVIEW >

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MANAGEMENT'S DISCUSSION AND ANALYSIS

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2004 and 2003.

OVERVIEW

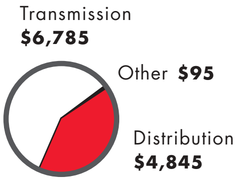
We are wholly owned by the Province of Ontario (the Province) and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario. Our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in safety, customer service and reliability, while providing a great working environment for our employees and creating shareholder value. In 2004, we continued our focus on our core businesses, substantially maintained or improved our performance, and contributed to the rebuilding of Ontario's core infrastructure.

Transmission

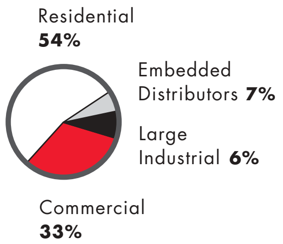
Substantially all of Ontario's electricity transmission system is owned and operated by our company. In 2004, we earned total transmission revenues of $1,262 million primarily by transmitting approximately 153.4 TWhs of electricity, directly or indirectly, to more than 4 million customers. Our transmission 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 3,900 MWs and exports of approximately 5,800 MWs of electricity.

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 46 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, the majority of the $2,874 million in distribution revenue which we earned in 2004 was from our residential customers.



TOTAL ASSETS
December 31, 2004
(Cdn $ millions)



2004 DISTRIBUTION REVENUES

Other

Our other business segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc. This subsidiary markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. This segment contributed revenues of $17 million in 2004 and has assets of about $95 million, which constitute less than 1% of our total assets.

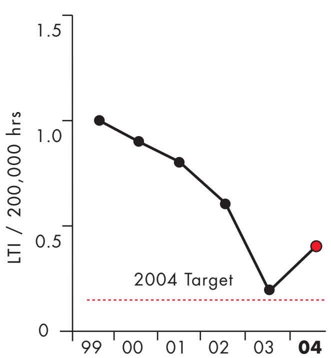
Our Strategy

In 2004, we maintained our focus on the strategic direction established in 2002 and built upon our accomplishments. Our goals are to be recognized by our customers as their best service provider; by our employees as the best place to work in Canada; 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 more customer-friendly 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 our large and mid-sized customers, acknowledging their commercial requirements.
- **Reliability:** Further enhance the reliability of our transmission and distribution systems while continuing to develop and expand the transmission system to meet Ontario's future needs. Furthermore, we will continue to make productivity and cost reduction improvements. The resulting savings will be largely reinvested into the work programs.
- **Financial:** Ensure our actions contribute towards maximizing the value of our company, while maintaining an effective borrowing capability through stable credit quality and delivering stable 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 2004 objectives, improving in a number of areas over 2003 levels, and are moving forward to meet our strategic goals.



LOST-TIME INCIDENTS FREQUENCY RATE

As we work in an environment with significant hazards, safety is our top priority and we set aggressive targets to improve our performance. 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 injuries. Although we did not achieve our aggressive safety targets for the year, the number of these serious incidents in 2004 was 19% lower than last year. As shown in the adjoining chart, since 1999 our lost-time accident frequency rate has dropped by about 60%, placing us in the top quartile of Canadian transmission and distribution companies. The majority of our 2004 lost-time incidents were related to strain and exertion rather than to serious injuries related to electrical incidents or fall from heights. 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 a coaching and mentoring program, developmental rotations, an injury/exertion prevention program and a fleet safety program.

In 2004, we substantially improved our large-sized customer satisfaction survey results over 2003 levels and exceeded our 2004 target by about 5%. We also improved our transmission system reliability over our 2003 levels as well as outperformed our 2004 target. Largely due to severe weather conditions in December, we missed our distribution reliability target for frequency of interruptions, although we did realize significant improvements in the duration of these interruptions. With the exception of December results, we improved 2004 performance in customer reliability and service through a strong operational focus on the reliability of the aging transmission and distribution system, along with fewer interruptions due to weather and wildlife. A number of key initiatives were undertaken during the year to improve performance, including improved crew scheduling to allow faster restoration response to unplanned outages. This contributed to minimizing the length of the unplanned outages in our distribution system during the severe weather conditions in December. Building on the momentum achieved in the past two years, over the next few years 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 with us and reduce our response time to customer requests.

Strong financial performance again characterized our 2004 results, and we persisted in upgrading our assets and improving reliability through key investments in our transmission and distribution work programs which will continue in 2005 and beyond.

REGULATION

Our electricity transmission and distribution businesses are regulated by the OEB. The OEB sets rates for customers based on the level of revenue required to operate our regulated businesses and to earn our 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 spot market administered by the Independent Electricity System Operator (IESO, formerly the Independent Electricity Market Operator). 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 and there was a complete restoration of the normal regulatory framework for transmission rates. The fixed commodity price was replaced with a two-tiered pricing structure, effective April 1, 2004. Under this structure, low volume and designated consumers pay 4.7 cents per kWh for the first 750 kWh of electricity consumed each month and 5.5 cents per kWh for all additional electricity consumption. This act also provides for the OEB to assume responsibility for establishing future commodity prices for low volume and designated consumers commencing no later than May 1, 2005.

On December 9, 2004, the Ontario Legislature passed the *Electricity Restructuring Act, 2004*. This act, many aspects of which were effective January 1, 2005, is intended to result in stable prices for consumers that reflect the full cost of electricity, facilitate new supply additions, and promote conservation and demand management. The act also creates the Ontario Power Authority (OPA), with a mandate to ensure an adequate, long-term supply of electricity in Ontario. The IESO will continue to be responsible for operating the system and the spot market, and shorter-term system planning.

Under the new market structure, wholesale electricity consumers will pay a blend of regulated, contracted and spot market prices for electricity. At the retail level, a regulated price plan approved by the OEB will be available for residential and low volume consumers. The regulated price plan is expected to take effect on April 1, 2005 and will be based on wholesale electricity costs including a blend of regulated, contracted and expected spot market prices for the commodity. The regulated price will be adjusted in 2006 to ensure consumers pay the full cost of electricity including the commodity cost. Cost recovery shortfalls or overpayments will be administered by the OPA and passed through to consumers over the year. As a result, distributors, including our company, will not be exposed to commodity price risk.

While much of the industry restructuring to date has been focussed on the commodity, the Province initiated a process in December 2004 to examine the future of Ontario's electricity transmission and distribution sector. In particular, the Province is seeking public input on solutions and approaches to achieve greater efficiencies in the electricity distribution sector; to promote the development of distributed generation; and to address issues relating to transmission planning and investment. As the largest Ontario transmitter and distributor, we continue to participate in these initiatives to further enhance the efficiency and reliability of the transmission and distribution sectors. In the interim, the Province expects us not to enter into further transactions involving the acquisition or divestment of local distribution companies or distribution assets.

Transmission Rates

The IESO remits payments to us based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. These rates were set based on an approved 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%.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers approved distribution rates, purchased power costs, and other approved regulatory charges. Our distribution rates are also approved by the OEB, based on a revenue requirement that includes a rate of return.

The *Electricity Pricing, Conservation and Supply Act, 2002* suspended an approved distribution rate increase for all local distribution companies in Ontario that was scheduled to be effective on March 1, 2003. It also suspended our approved rate changes associated with low voltage services for embedded local distribution companies and direct customers. Subject to OEB direction, distributors will be allowed to implement, amongst other charges, the March 1, 2003 rate increase on April 1, 2005. The rate increase will be conditional on each distributor investing an amount, based on one year of the incremental revenue, in conservation and demand management initiatives. We filed our conservation and demand management plan with the OEB in January 2005 and anticipate our expenditures to be in the range of $40 million.

In June 2004, the OEB initiated the process to establish electricity distribution rates for all local distribution companies in 2006. The process involves establishing updated revenue requirements for distributors in 2006 based on cost of service. The OEB is currently developing the *2006 Electricity Distribution Rate Handbook* that will provide filing guidelines for distribution companies in making a rate application. We continue to closely monitor this process and we expect to file a distribution rate application during 2005 to establish our 2006 distribution rates.

In December 2004, we received OEB approval for distribution rate adjustments, regarding the prudence of distribution-related deferral account balances, beginning March 1, 2005. The recovery of these 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 local distribution companies and direct customers, market-ready transition costs, retail settlement variance account balances, and certain environmental costs. As a result of this decision, the OEB will adjust our rates for implementation effective April 1, 2005.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	**2004**	2003	$ Change	% Change
Transmission	**1,262**	1,298	(36)	(3)
Distribution	**2,874**	2,734	140	5
Other	**17**	26	(9)	(35)
	4,153	4,058	95	2
Average annual Ontario 60-minute peak demand *(MW)*[1]	**22,375**	22,317	58	—
Distribution – units distributed to our customers *(TWh)*[1]	**28.5**	27.9	0.6	2

[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, including a factor related to individual customer's maximum demand, which occur at different times from the overall system peak.

While the average annual peak demand was marginally higher this year, the contribution of our individual customers' peak demands was lower for most of the year resulting in lower transmission tariff revenues. This reduction is reflective of more moderate temperatures in 2004. Transmission revenues also include a minor amount of ancillary revenues, which were also lower than last year due to a reduction in services provided to other industry participants for station maintenance services, and a reduction in revenue associated with export and wheeling fees.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB approved rates, recovery of the cost of purchased power used by our customers, and a minor amount of ancillary distribution services revenue. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power.

Distribution revenues increased in 2004, primarily due to the recovery of higher purchased power costs. Recoveries for purchased power costs increased by $115 million, reflecting the implementation of the two-tiered pricing structure on April 1, 2004, partially offset by a lower average Hourly Ontario Energy Price (HOEP), as described below under "Purchased Power." The remaining increase principally relates to marginally higher distribution tariff revenues from increased electricity consumption and higher ancillary revenues, including the amount related to power restoration efforts in Florida under a North American mutual-assistance agreement.

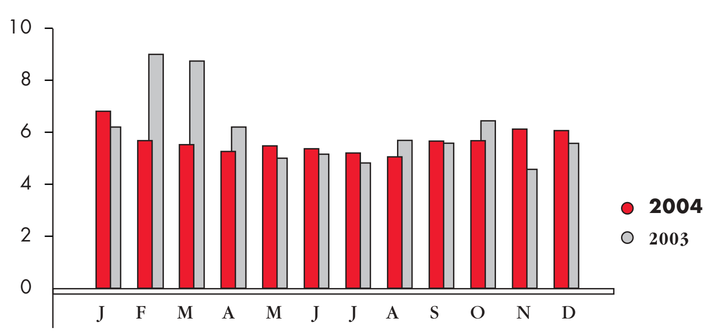
Other

Other revenue decreased compared to 2003 results, primarily due to lower dark fibre sales 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. For certain low volume and designated customers, the wholesale commodity price of electricity was fixed at 4.3 cents per kWh. On April 1, 2004, this fixed price was replaced by a two-tiered pricing structure of 4.7 cents per kWh for the first 750 kWhs consumed each month and 5.5 cents per kWh for all additional electricity consumption. Customers not eligible for this pricing structure pay the wholesale commodity price of electricity, which is based on the HOEP established by the IESO spot market.

Purchased power costs increased by $115 million, or 6%, to $1,987 million in 2004 compared to last year. This increase primarily reflects higher commodity prices of $95 million, which were largely attributable to the implementation of the two-tiered pricing structure. The average monthly weighted-average HOEP declined by 0.48 cents per kWh to 5.19 cents per kWh over the year, partially offsetting the impact of the implementation of the two-tiered pricing structure. The remaining increase in purchased power costs primarily reflects higher electricity consumption.



WEIGHTED-AVERAGE ONTARIO HOEP

(Cents/kWh)

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are primarily comprised of labour, material, equipment and purchased services in support of the transmission and distribution systems. These costs also include property taxes on our transmission and distribution lines, stations and buildings.

As a result of our actuarial valuation filed with the Financial Services Commission of Ontario (FSCO) on September 22, 2004, we are required to contribute approximately $80 million to our pension plan in each of the three years over the period 2004 through to 2006. Such pension contribution costs are attributed to labour and are either charged to operation, maintenance and administration expense or are capitalized as part of the cost of fixed assets. In response to our June 1, 2004 pension application, the OEB issued an order on July 14, 2004 approving the establishment of a regulatory deferral account to record that portion of our distribution-related pension contributions, plus interest, that would otherwise have been charged to operation, maintenance and administration expense. Given the OEB's order, we determined that it was appropriate to recognize approximately $34 million of distribution-related pension costs as a regulatory asset.

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

Year ended December 31 (Canadian dollars in millions)	**2004**	2003	$ Change	% Change
Transmission	**356**	382	(26)	(7)
Distribution	**392**	387	5	1
Other	**23**	26	(3)	(12)
	771	795	(24)	(3)

Transmission

Expenditures incurred to sustain our high-voltage transmission stations, lines and rights of way decreased by $26 million compared to last year. This reduction was primarily due to the reassignment of supporting resources to our larger transmission capital work program and a reduction in ancillary station maintenance services. During 2004, we maintained last year's higher work program levels associated with safety and reliability standards at our transmission sites. We also incurred higher expenditures for station corrective maintenance. The overall reduction in our operation, maintenance and administration expense was partially offset by the impact of the funding requirements for our pension plan.

Distribution

Operation, maintenance and administration expenditures made by our distribution business, including those made on our stations, lines and associated rights of way, increased by $5 million in 2004. This overall increase reflects marginally higher forestry expenditures made to clear trees and brush from our rights of way. Our plan is to increase the frequency of our trimming cycles to maintain reliability. During 2004, we maintained the overall level of customer care expenditures, including the impact of implementing the electricity policies of the Province. Under a North American mutual-assistance agreement, we also provided significant assistance to the Florida Power and Light Company in restoring power after several large hurricanes struck the Southern U.S. during August and September 2004. The increased expenditures were partially offset by the impact of lower storm and trouble call costs, attributable to an overall improvement in weather conditions, on our own system.

Other

Other operation, maintenance and administration costs were reasonably consistent with the comparative period, and primarily reflect costs associated with fibre-optic cable.

Depreciation and Amortization

Depreciation and amortization expense increased by $26 million, or 6%, to $480 million in 2004. This increase primarily results from higher depreciation charges associated with our fixed assets in service, consistent with the investments made in our electricity delivery network.

Regulatory Recovery

The *Electricity Pricing, Conservation and Supply Act, 2002*, suspended a previously approved rate increase of approximately $25 million per year related to annual low voltage services costs for embedded local distribution companies and direct customers. The associated costs are charged annually to our results of operations. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002*, also allowed for the establishment of a regulatory deferral account to record the 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, we did not reflect certain other costs, such as interest, as regulatory assets in prior years' financial statements.

On May 31, 2004, we applied for recovery of approximately $156 million included within various regulatory deferral accounts prior to December 31, 2003. The requested recovery primarily included 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 written and oral evidence we submitted, the OEB issued a decision on December 9, 2004 regarding the prudence of the distribution-related deferral account balances included in our 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, we recorded an increase in our regulatory asset balance which primarily reflects future recovery of costs that had been previously charged to results of operations without recognition of corresponding revenue.

Financing Charges

Financing charges declined by $17 million, or 5%, to $331 million, reflecting the refinancing of our debt at lower average interest rates compared to the effective rates on the maturing debt. Average debt levels were comparable in 2004 and 2003.

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 taxes decreased by $16 million, or 8%, to $177 million compared to 2003. This decrease is attributable to higher tax deductions, primarily resulting from our 2004 pension contributions, a portion of which have been capitalized or deferred, and a reduction in the statutory tax rate from 36.62% to 36.12%. The majority of our $91 million regulatory recovery reported in 2004 will be taxable in future periods as associated amounts are recovered from customers.

Net Income

Net income increased by $102 million, or 26%, to $498 million in 2004. This increase substantially reflects our successful regulatory recovery of low voltage services costs previously incurred but suspended by the *Electricity Pricing, Conservation and Supply Act, 2002.* Excluding this one-time amount, the impact on net income of lower operation, maintenance and administration costs, including the impact of reassigning resources to support a larger capital work program, and lower financing costs, was substantially offset by higher depreciation charges, consistent with the investments made in our electricity delivery system, and lower transmission revenues.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2003 through December 31, 2004. 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 includes 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)		**2004**				2003		
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sep. 30	Jun. 30	Mar. 31
Total revenues[1,2]	**1,074**	**1,018**	**960**	**1,101**	1,009	949	953	1,147
Net income[1,2]	**186**[3]	**133**	**59**	**120**	79	93	85	139
Net income to common shareholder[1,2]	**181**	**129**	**55**	**115**	75	88	81	134

[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 profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[3] As a result of the oral and written evidence we submitted, the OEB issued a ruling, on December 9, 2004, 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.

LIQUIDITY AND CAPITAL RESOURCES

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

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	2004	2003
Operating activities	**911**	1,032
Investing activities		
Capital expenditures	**(727)**	(597)
Financing activities		
Long-term debt issued	**540**	1,250
Long-term debt retired	**(472)**	(879)
Short-term notes payable	**15**	(554)
Dividends paid	**(265)**	(244)
Other financing and investing activities	**26**	(10)
Net change in cash and cash equivalents	**28**	(2)

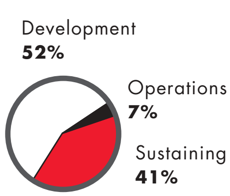
Operating Activities

Net cash from operating activities was lower than last year by $121 million. This reduction primarily reflects higher working capital requirements during 2004. The introduction of the two-tiered pricing structure in 2004, combined with weather-driven variances in consumption and changes in purchased power costs, resulted in an increase in our working capital requirements compared to last year. Other factors impacting our working capital requirements included the timing of installment payments for corporate income taxes and interest payments, as well as the requirement to begin funding our pension plan. Our regulatory recoveries arising from the December 9, 2004 OEB decision will begin to impact our cash from operations only when recovery occurs over the period 2005 to 2008.

Investing Activities

Cash used for investing activities primarily represents capital expenditures to enhance and reinforce our transmission and distribution systems, which were as follows:

Year ended December 31 (Canadian dollars in millions)	2004	2003	$ Change	% Change
Transmission	**432**	289	143	49
Distribution	**288**	292	(4)	(1)
Other	**7**	16	(9)	(56)
	727	597	130	22



2004 Transmission Capital Expenditures

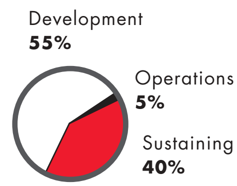
Transmission

Capital expenditures made by our transmission business were $432 million and $289 million in 2004 and 2003, respectively. Investments in 2004 to expand and reinforce our transmission system increased significantly from $56 million in the prior year to $223 million. These investments, which include the construction of the new Parkway Transformer Station, result from growing loads and the planned closure of the Lakeview Generating Station. Capital expenditures associated with sustaining our transmission system were $176 million compared to $184 million in 2003. The small year-over-year reduction reflects lower spending on our transport and work equipment and telecommunications assets, partially offset by an increase in capital expenditures made to ensure the continued reliability of our existing transmission stations and lines and to reinforce our transmission operations. Other capital expenditures incurred to support our transmission business decreased by $16 million to $33 million this year as a result of the substantial completion of our integrated operating facility, the Ontario

Grid Control Centre. This facility was officially opened in August 2004 and is expected to achieve cost efficiencies, improve customer response and provide advanced monitoring and analysis capabilities. The funding requirements associated with our pension plan also contributed to increasing our capital expenditures across our work program this year.

Distribution

Capital expenditures made by our distribution business were $288 million in 2004 compared to $292 million in 2003. Expenditures to enhance our distribution system to accommodate increased loads, improve performance and mitigate risks increased by $33 million to $157 million this year. These expenditures reflect a stable level of connection and upgrade work in the year combined with the effects of changes to the OEB's *Distribution System Code*, which resulted in our company funding a greater proportion of customer-shared new connection and system upgrade costs than in prior years. Capital expenditures incurred to sustain the existing distribution system were $116 million, a reduction of $40 million compared to 2003. This reduction was attributable to lower storm damage and emergency trouble call power restoration work due to improved weather and reduced spending on transport and work equipment. Consistent with our strategy, we also had a one-time reduction in our wood pole replacement program this year to facilitate the introduction of an improved work prioritization process that will benefit this work program going forward. Other capital expenditures within our distribution business were $15 million, an increase of $3 million from last year. The funding requirements associated with our pension plan also had an impact on our capital expenditures across our work program this year.



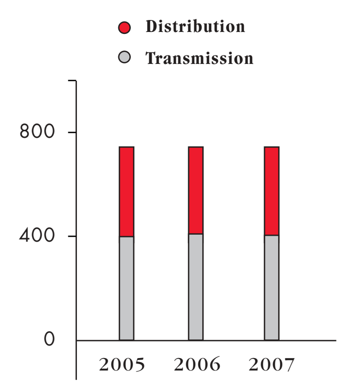
2004 Distribution Capital Expenditures

Other

Other capital expenditures, primarily incurred by our telecommunications business, decreased by $9 million this year. This reduction reflects the substantial completion of our fibre-optic network last year and a 2004 capital program that reflected ongoing equipment upgrades commensurate with demand.

Future Capital Expenditures

Our capital expenditures in 2005 are budgeted at about $745 million, an increase of approximately $18 million over our 2004 levels. The budgets for our transmission and distribution businesses are about $400 million and $340 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 adjoining chart, are expected to stay at the same general level over the next few years.



Future Capital Expenditures
(Cdn $ millions)

Transmission

With the completion of the Parkway project and the Ontario Grid Control Centre, transmission system capital expenditure levels are expected to decline between 2004 and 2005. The consistent level of capital expenditures over the following years is largely the result of transmission development work tied to our 10-year transmission plan, *Transmission Solutions 2004-2013*. These investments ensure that growing area supply demands and system configuration and reliability requirements, including increased access to the Ontario market, are successfully met. Specific initiatives which are or will be underway include the Niagara Reinforcement project, which will relieve transmission bottlenecks that limit transfer of Niagara area generation and imports from New York state; the completion of work associated with the Lakeview coal-fired station retirement; and supply improvements in the Greater Toronto Area, including the Parkway

Transformer Station and an underground cable project in downtown Toronto, as well as in Southwestern Ontario. The timing of many of these projects is uncertain as they are dependent upon needs and, in some instances approvals by various regulatory bodies, as well as negotiations with customers, neighbouring utilities and other stakeholders. In particular, we continue to explore interconnection enhancement possibilities with our neighbouring utilities; however no specific project costs are included in our plan. Presently, joint studies are underway with Michigan and also with Manitoba following the Province's announcement to proceed to the next technical study phase of this latter initiative. Bringing electricity supply from the northern region of Manitoba represents an extensive and complex undertaking with many parties that would take close to a decade to complete, at a total transmission system cost currently estimated to be in the range of $1.5 to $2 billion. None of these projects will be undertaken unless the necessary approvals are granted, including that of the OEB.

In addition to the developmental investments discussed above, there is also increased spending 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, with an emphasis on assets critical to high voltage transmission network integrity. Some of this spending results from a review, which we undertook in 2004, of critical assets such as 500 kV lines. Spending on station ancillary components is also consistent with the recommendations from the August 14, 2003 blackout. As most of the blackout recommendations are already standard work practices, we require only marginal incremental funding to implement them.

Distribution

We will continue to replace and improve our aging distribution asset base in order to maintain system reliability. Increasing investments will be made within the distribution business, in particular reflecting increased wood pole replacements. Across Ontario, we are continuing with the replacement of older distribution systems with higher voltage and more current standard installations. For example, the replacement of the distribution network in downtown Timmins, which is currently underway, will be completed in 2007.

In June 2004, the Province established targets to install "smart meters" for all electricity consumers in Ontario. These meters will be capable of the following: measuring and reporting usage over predetermined periods, being read remotely, and providing customers with convenient access to information about their electricity consumption. Smart meters are regarded as an integral means of promoting a culture of conservation. Targets established by the Province require 800,000 meters to be installed in Ontario by 2007, and replacement of all remaining meters by 2010. It is estimated that our implementation costs could be in the range of $600 million. 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. The OEB, with stakeholders' input, submitted an implementation plan to the Province in January, 2005 for their review. Due to the high level of uncertainty surrounding the implementation details of the smart meters program, and our anticipation that the resulting expenditures will be fully recoverable, no specific costs have been included in our capital expenditures outlook at this time.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are able to issue up to $750 million in short-term notes with a term to maturity of less than 365 days. This program is supported by a committed revolving credit facility with a syndicate of banks. Following our August 13, 2004 amendment of our credit agreement, primarily to cancel a $250 million 5-year facility, this facility amounts to $750 million. At December 31, 2004, we had $40 million in short-term notes outstanding. The available short-term liquidity under this program and anticipated levels of funding from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including through our medium-term note program. The principal amount issuable and available until July 2005 under this program is $960 million. We intend to renew this program. Our notes and debentures mature between 2005 and 2043. We currently plan to refinance maturing debt principally through our medium-term note program.

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit 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, 2004, we were in compliance with all of these covenants and limitations.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
Standard & Poor's Rating Services Inc.	A-2	A
Dominion Bond Rating Service Inc.[1]	R-1 (low)	A
Moody's Investors Service Inc.	Prime-1	A2

[1] On January 31, 2005, Dominion Bond Rating Service Inc. changed the trend on our long-term debt rating from Stable to Positive and confirmed our short-term debt rating.

During 2004, we issued $540 million in long-term debt under our medium-term note program and we repaid $472 million in maturing long-term debt. We also increased our short-term notes outstanding by $15 million. In comparison, during 2003 we issued $1,250 million and retired $879 million in long-term debt, and we reduced our short-term notes payable by $554 million.

In 2004, we paid dividends to the Province in the amount of $265 million, consisting of $247 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $226 million and preferred dividends of $18 million.

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, 2004 (Canadian dollars in millions)	Total	2005	2006/2007	2008/2009	After 2010
Contractual Obligations (due by year):					
Short-term notes payable	40	40	—	—	—
Long-term debt	5,232	539	1,093	750	2,850
Inergi LP (Inergi) outsourcing agreement[1]	734	115	224	196	199
Operating lease commitments	21	6	9	6	—
Total Contractual Obligations	**6,027**	**700**	**1,326**	**952**	**3,049**
Other Commercial Commitments (by year of expiry):					
Bank line[2]	750	750	—	—	—
Letters of credit[3]	117	117	—	—	—
Guarantees[3]	275	275	—	—	—
Pension[4]	169	81	88	—	—
Total Other Commercial Commitments	**1,311**	**1,223**	**88**	**—**	**—**

[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 2005, with a two-year term out option.

[3] We currently have bank letters of credit of $80 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 $33 million and parental guarantees of $275 million. The amount of prudential support that we provide in the form of bank letters of credit to the IESO is dependent on our long-term credit ratings from major Canadian and U.S. rating agencies. The amount of bank letters of credit provided would need to increase if our credit ratings deteriorated. For example, if our credit rating declined to BBB+, the amount of bank letters of credit required to meet our prudential support obligation would be two times our current amount, and if our credit rating declined to BB+, the amount of bank letters of credit required to meet our prudential support obligation would be four times the current amount. The remaining 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 as at December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Should financial market conditions improve significantly before December 31, 2006, we have the option to file an earlier actuarial valuation.

The amounts in the above table under short-term notes payable and long-term debt 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

The OEB's December 9, 2004 decision allowing 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. 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 at some future date, the appropriate amount will be reflected in results of operations in the period that the OEB decision occurs.

On July 14, 2004, the OEB issued an order approving the establishment of a regulatory deferral account to record all pension-related cash payments for our distribution business, including interest thereon. The regulatory asset will also include about $16 million payable to Inergi commencing in 2005, which relates to pension costs of transferred staff. The prudence of these expenditures is expected to be reviewed by the OEB as part of our application for 2006 rates. However, the OEB did confirm in its order that prudently incurred pension costs are normally recoverable as part of a general rate adjustment application. We anticipate our deferred distribution pension expenditures to be recoverable in future. Should the OEB at some future date deem some or all of these expenditures to be imprudent, we would charge the disallowed amount to results of operations in the period such a decision was made.

The OEB has recognized the need to compensate utilities for lost revenue resulting from a successful conservation and demand management program, 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. This code revision could result in significant future revenue loss to our transmission business and there is currently no assurance that we would be adequately compensated.

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 these impacts.

There is also a risk we could be required to incur unexpected capital expenditures to maintain or improve our transmission and distribution assets and to connect new third-party generation assets. We expect to be required to make material future capital investments in new technologies, 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 and charges to 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

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 a labour dispute we could face some degree of operational risk related to continued compliance with our license requirements of providing service to customers. We also face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. Existing collective agreements with the PWU and The Society will expire on March 31, 2005. On January 30, 2005, we arrived at a tentative agreement with the PWU. This agreement is subject to ratification by the union. Negotiations with The Society are currently underway and we anticipate that a balanced settlement will be reached.

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.

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. Environmental assessments and seeking government approvals for the construction of facilities could result in delays and cost increases.

Future changes in environmental regulations, or in their enforcement, may result in material changes to the 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 liability 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 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 revenue requirements. 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 2005 and 2006 would have an impact on net income of approximately $2 million in 2005 and $5 million in 2006.

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.

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 local distribution companies 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, 2004 amounted to $443 million and principally relate to employee future benefits other than pension, the regulatory asset recovery amount (RARA), environmental costs, pension costs and low voltage services from 2004. We have also recorded regulatory liabilities pertaining 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 accepts the relevant regulatory treatment, as it has for the employee future benefits other than pension regulatory asset and the RARA, or if OEB acceptance is judged to be probable. If reflection in future rate-setting by the OEB is determined to be no longer probable, the relevant regulatory asset or liability would no longer be supportable and, accordingly, would be charged or credited to results of operations in the period in which that determination 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). As a result of our actuarial valuation filed with FSCO on September 22, 2004, we are required to contribute approximately $80 million to our pension plan in each year over the period 2004 through to 2006. Contributions after 2006 will be based on an actuarial valuation as at 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 with reference to 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 60% held in listed equity securities and 40% held in corporate and government debt securities. 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 weighted-average discount rate is determined by reference to the most recently available market interest rates based on AA corporate bond yields reflecting an average duration of approximately 13 years.

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 weighted-average discount rate used to calculate the accrued benefit obligations is determined by reference to the most recently available market interest rates based on AA corporate bonds yields reflecting the duration of the applicable employee future benefit plan.

The costs of employee future benefits other than pension are determined at the beginning of each year, based on updated actual claiming experience and future health care inflation and salary scale assumptions. Per capita claim costs have been increasing most recently as a result of rising health care cost trends, primarily for prescription drug and extended health care benefits. A 1% increase in the health care cost trends would result in an increase in the service cost and interest cost of about $11 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 year charge to our results of operations or the amount capitalized to the 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 2004, subsequent to the OEB's December 9, 2004 decision. As a result of our review, we determined that the carrying value of our goodwill has not been impaired.

EMERGING ACCOUNTING PRONOUNCEMENTS

Accounting Guideline 13 *Hedging Relationships*

Effective January 1, 2004, we adopted CICA Accounting Guideline 13 *Hedging Relationships* (AcG 13). AcG 13 governs the identification, designation, documentation and effectiveness of hedging relationships for the purpose of applying hedge accounting, as well as the discontinuance of hedge accounting. Each of our hedging relationships complies with the requirements of AcG 13.

Accounting for Rate Regulated Operations

The Accounting Standards Board (AcSB) of the Canadian Institute of Chartered Accountants (CICA) has an active project to review generally accepted accounting principles applicable to enterprises with rate-regulated operations. Should the AcSB determine that regulatory accounting treatments, which are commonly applied throughout our industry, do not meet the definition of an asset or liability as defined by CICA Handbook Section 1000 *Financial Statement Concepts*, 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 $443 million and $576 million, respectively at December 31, 2004. 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 the results of operations once the new accounting standard became effective, dependent on the transition rules. The AcSB expects to issue an exposure draft in late 2005. At this time, it is uncertain what decision the AcSB will reach, however we do not believe that the outcome of this CICA project will have a materially adverse financial impact on our company. In the interim, the AcSB has issued an exposure draft dealing with disclosures and presentation matters only, to be effective in 2005. The guideline, if implemented, would not result in significant changes in our disclosures.

OUTLOOK

We will continue to focus upon 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 which have the potential to cause serious injuries, further enhance the reliability of our transmission network while at the same time maintaining the reliability of our distribution network, and to improve our customers' level of satisfaction. To this end, we have renewed our focus on incident prevention and proactive applications, and we are making significant investments to address asset condition and reliability risk by maintaining and selectively increasing the work program spending levels. In particular, we will ensure that Ontario's needs for performance from our aging transmission system under tight generation supply are met. The condition of our assets and our reliability risk will continue to be maintained at reasonable levels. Key transmission investment areas are power equipment, protection and control equipment, ancillary systems and overhead and underground lines, with an emphasis on critical stations. Key distribution investment areas include vegetation management, distribution system reinforcements and the new conservation and demand management program, as well as customer care programs.

Consistent with our current 10-year transmission plan, we will make the necessary new investments in our transmission infrastructure to ensure that growing area supply demands, 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 in Southwestern Ontario. Further, we plan to undertake reinforcement projects such as that in the Niagara region. As part of these initiatives, we will work closely with the OPA, the OEB and other stakeholders as well as related or affected parties. Reaching agreements with all affected parties is necessary before we would proceed with large, complex undertakings such as the proposed system expansion to support new supply from Manitoba Hydro which the Province is currently investigating and we are currently engaged in a joint study.

We anticipate that the Province's implementation plans for its "smart meter" program will be announced later in 2005. We will actively work towards putting this program in place in the most effective manner. It is currently estimated that we may spend in the range of $600 million on capital expenditures to implement the smart meter program between 2005 and 2010. The Province has announced that these costs should be recoverable in rates.

The Ontario electricity industry continues to be in the midst of a fundamental restructuring. In December 2004, the Government issued a paper, *Electricity Transmission and Distribution in Ontario – A Look Ahead*, for discussion and consultation purposes. We will continue to provide leadership in shaping a streamlined power sector that effectively addresses the needs of small, medium and large customers for safe, reliable and affordable power. We will work with the Province and various interest groups to promote a consistent and well supported vision of how the industry should evolve, with particular focus on the appropriate role for wires infrastructure in the sector. We will also continue to input into the Province's policy review for restructuring the distribution sector in Ontario.

With the recent amendments to the legislation affecting the electricity industry and the OEB's mandate, the approval of recovery for distribution regulatory assets in December, 2004 and the expected distribution rate increases in April 2005, we anticipate a more stable regulatory environment going forward.

Through this period, we anticipate that our financial returns will be sufficient to maintain a reasonable financial condition, current credit quality and current 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 11, 2005. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

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

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 11, 2005.

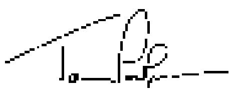
In meeting the responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective 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 46, outlines the scope of their examination and their opinion.

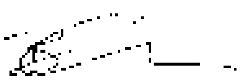
The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and 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 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

Absent: Dave Barrie, Senior Vice-president, Asset Management

AUDITORS' REPORT

To the Shareholder of Hydro One Inc.:

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2004 and December 31, 2003, 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, 2004. 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, 2004 and December 31, 2003, the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2004, in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP
Chartered Accountants
Toronto, Canada

February 11, 2005

CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	2004	2003
Revenues		
Transmission (Note 14)	1,262	1,298
Distribution (Note 14)	2,874	2,734
Other	17	26
	4,153	4,058
Costs		
Purchased power (Note 14)	1,987	1,872
Operation, maintenance and administration	771	795
Depreciation and amortization (Note 4)	480	454
	3,238	3,121
Regulatory recovery (Note 3)	91	—
Income before financing charges and provision for payments in lieu of corporate income taxes	1,006	937
Financing charges (Note 5)	331	348
Income before provision for payments in lieu of corporate income taxes	675	589
Provision for payments in lieu of corporate income taxes (Notes 6 and 14)	177	193
Net income	498	396
Basic and fully diluted earnings per common share (Canadian dollars) (Note 13)	4,798	3,779

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	2004	2003
Retained earnings, January 1	654	502
Net income	498	396
Dividends (Note 13)	(265)	(244)
Retained earnings, December 31	887	654

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	**2004**	2003
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $18 million; 2003 - $18 million) (Note 14)	**707**	616
Materials and supplies	**47**	45
	754	661
Fixed assets (Note 7):		
Fixed assets in service	**14,940**	14,362
Less: accumulated depreciation	**5,475**	5,175
	9,465	9,187
Construction in progress	**348**	278
	9,813	9,465
Other long-term assets:		
Deferred pension asset (Note 11)	**534**	584
Regulatory assets (Note 8)	**443**	421
Goodwill	**133**	133
Long-term accounts receivable and other assets	**25**	20
Deferred debt costs	**23**	22
	1,158	1,180
Total assets	**11,725**	11,306

See accompanying notes to Consolidated Financial Statements.

December 31 (Canadian dollars in millions)	2004	2003
Liabilities		
Current liabilities:		
Bank indebtedness	**9**	37
Accounts payable and accrued charges (Note 14)	**630**	620
Accrued interest	**44**	38
Short-term notes payable (Note 9)	**40**	25
Long-term debt payable within one year (Note 9)	**539**	472
	1,262	1,192
Long-term debt (Note 9)	**4,613**	4,539
Other long-term liabilities:		
Regulatory liabilities (Note 8)	**576**	587
Employee future benefits other than pension (Note 11)	**654**	597
Environmental liabilities (Note 12)	**74**	69
Long-term accounts payable and accrued charges	**22**	31
	1,326	1,284
Total liabilities	**7,201**	7,015
Contingencies and commitments (Notes 10, 16 and 17)		
Shareholder's equity (Note 13)		
Preferred shares (authorized: unlimited; issued: 12,920,000)	**323**	323
Common shares (authorized: unlimited; issued: 100,000)	**3,314**	3,314
Retained earnings	**887**	654
Total shareholder's equity	**4,524**	4,291
Total liabilities and shareholder's equity	**11,725**	11,306

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)	2004	2003
Operating activities		
Net income	**498**	396
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	**446**	417
Amortization of discount	**62**	60
Retail settlement variance accounts	**29**	21
Regulatory recovery (Note 3)	**(91)**	—
	944	894
Changes in non-cash balances related to operations (Note 15)	**(33)**	138
Net cash from operating activities	**911**	1,032
Investing activities		
Capital expenditures	**(727)**	(597)
Other assets	**19**	3
Net cash used in investing activities	**(708)**	(594)
Financing activities		
Long-term debt issued	**540**	1,250
Long-term debt retired	**(472)**	(879)
Short-term notes payable	**15**	(554)
Dividends paid	**(265)**	(244)
Termination of forward sale	**—**	(12)
Other	**7**	(1)
Net cash used in financing activities	**(175)**	(440)
Net change in cash and cash equivalents	**28**	(2)
Cash and cash equivalents, January 1	**(37)**	(35)
Cash and cash equivalents, December 31 (Note 15)	**(9)**	(37)

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

01 > 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).

02 > 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).

Effective January 1, 2003, Hydro One Networks and Hydro One Network Services were combined. Hydro One Network Services, the former Ontario Hydro Energy and Hydro One Markets will be dissolved pursuant to the *Business Corporations Act* (Ontario).

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. 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 gives 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 8.

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 prudence. 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.

02 >
SIGNIFICANT ACCOUNTING POLICIES
(continued)

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 tariff 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, 2004 amounted to $318 million (2003 - $286 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. During 2003, Hydro One adopted the Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3110, *Asset Retirement Obligations*. This accounting standard requires the Company to determine the fair value of the future expenditures required to settle legal obligations to remove fixed assets. If reasonably estimable, a liability is recognized equal to the present value of the estimated future removal expenditures. An equivalent amount is capitalized as an inherent cost of the associated fixed asset.

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.

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 (2004 - 7.0%; 2003 - 7.4%).

02 >
SIGNIFICANT ACCOUNTING POLICIES
(continued)

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	42

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and 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, as defined in CICA Handbook Section 3110, 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 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 CICA 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 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 and are presented net with long-term 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.

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.

03 > 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 local distribution companies 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 regulatory recovery consists 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

04 > DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	**2004**	2003
Depreciation of fixed assets in service	**370**	339
Fixed asset removal costs	**34**	37
Amortization of regulatory and other assets	**76**	78
	480	454

05 > FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	2004	2003
Interest on short-term notes payable	1	6
Interest on long-term debt payable	286	306
Amortization of discount	62	60
Other	7	3
Less: Interest capitalized on construction in progress	(23)	(20)
Interest earned on investments	(2)	(7)
	331	348

06 > 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)	2004	2003
Income before provision for PILs	675	589
Federal and Ontario statutory income tax rate	36.12%	36.62%
Provision for PILs at statutory rate	244	216
(Decrease) increase resulting from:		
Net temporary differences:		
Regulatory recovery	(33)	—
Pension contribution in excess of pension expense	(23)	—
Interest capitalized for accounting purposes but deducted for tax purposes	(8)	(7)
Capital cost allowance in excess of depreciation and amortization	(7)	(16)
Employee future benefits other than pension expense in excess of cash payments	9	9
Environmental expenditures	(6)	(8)
Charge for staff reduction program lower than cash payments	—	(9)
Other	(9)	(10)
Net temporary differences	(77)	(41)
Permanent differences:		
Large corporations tax	16	17
Other	(6)	1
Net permanent differences	10	18
Provision for PILs	177	193
Effective income tax rate	26.22%	32.77%

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, 2004, future income tax liabilities of $224 million (2003 - $152 million), based on substantively enacted income tax rates, have not been recorded.

07 > FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
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**
2003				
Transmission	7,609	2,635	193	5,167
Distribution	4,828	1,817	61	3,072
Communication	645	273	15	387
Administration and service	790	394	9	405
Easements	490	56	—	434
	14,362	5,175	278	9,465

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 $23 million in 2004 (2003 - $20 million).

08 > 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 3):

December 31 (Canadian dollars in millions)	**2004**	2003
Regulatory assets:		
Employee future benefits other than pension	**168**	209
Regulatory asset recovery account	**121**	103
Environmental	**89**	83
Pension	**34**	—
Low voltage services	**26**	—
Other	**5**	26
Total regulatory assets	**443**	421
Regulatory liabilities:		
Deferred pension	**534**	584
Export and wheeling fees	**19**	—
Retail settlement variance accounts	**14**	—
Other	**9**	3
Total regulatory liabilities	**576**	587

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 4 years (2003 - 5 years) and does not earn a return.

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. 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.

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. 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, the Company has adjusted its future land assessment and remediation expenditure estimate and has increased its regulatory asset and offsetting environmental obligation (see Note 12) by approximately $16 million. During 2003, the Company reduced, by $64 million, its estimated long-term liability and offsetting regulatory asset for the management of polychlorinated biphenyls (PCBs). This reduction was due to expected revisions to draft regulations proposed by Environment Canada. 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 deferral account to record the Company's distribution-related pension contributions that would otherwise have been charged to 2004 results of operations. The regulatory asset will also include amounts payable to Inergi LP (Inergi) commencing 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 17). The amount related to the distribution business, as determined as at December 31, 2004, was approximately $16 million. 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 will include its request for recovery as part of its next general distribution rate application during 2005.

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 was highly probable that, at some future date, the OEB will also approve recovery of the low voltage amount attributable to 2004, plus interest. As a result, the Company has recognized a regulatory asset reflecting this probable future recovery.

08 > REGULATORY ASSETS AND LIABILITIES
(continued)

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.

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 attributable to 2004 activity in future rates.

09 > DEBT

December 31 (Canadian dollars in millions)	**2004**	2003
Short-term notes payable	**40**	25
Long-term debt:		
3.40% notes due 2004	**—**	235
3.45% notes due 2004	**—**	237
6.94% debentures due 2005	**200**	200
4.00% notes due 2005	**339**	339
4.10% notes due 2006	**109**	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[1]	**40**	—
4.00% notes due 2008	**500**	500
3.95% notes due 2009	**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**	200
6.59% notes due 2043	**315**	250
	5,232	5,164
Less: Long-term debt payable within one year	**(539)**	(472)
Net unamortized discounts	**(73)**	(144)
Unamortized hedging losses	**(7)**	(9)
Long-term debt	**4,613**	4,539

[1] 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 and with a weighted-average interest rate of 2.3% (2003 - 2.7%).

Hydro One has committed and unused revolving credit agreements with a syndicate of banks in the amount of $750 million maturing in August 2005. If used, interest on the lines of credit would apply based on Canadian benchmark rates. These credit agreements support 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 $2,000 million of which $960 million is remaining and is currently available until July 2005. The Company intends to renew this program.

09 > DEBT (continued)

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, 2004, 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 (Percent)
1 year	539	5.1
2 years	698	4.2
3 years	395	4.4
4 years	500	4.0
5 years	250	4.0
	2,382	4.4
6 – 10 years	1,250	6.3
Over 10 years	1,600	6.8
	5,232	5.6

10 > 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)	**2004**		2003	
	Carrying Value	**Fair Value**	Carrying Value	Fair Value
Long-term debt[1]	**5,232**	**5,658**	5,164	5,466

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

Hydro One enters into forward pay 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. During 2003, the Company terminated a forward sale agreement of $250 million in Government of Canada bonds for a net cash payment of $12 million that is being amortized on an annuity basis over the five-year term of the related debt. The Company also has offsetting interest rate swap agreements outstanding with the same counter-party. These agreements mature in 2011 and have notional principal amounts of $167 million (2003 - $167 million) and a net fair value of $nil (2003 - $nil).

As at December 31, 2004, 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 2004 (2003 - $nil).

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2004, 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, 2004, 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.

11 > 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 estimated at less than $1 million annually.

Plan Allocation

Hydro One's pension plan asset allocation at December 31, 2004 and 2003 was as follows:

	% of Plan Assets	
December 31	**2004**	2003
Equity securities	**59.2**	59.5
Debt securities	**36.2**	37.3
Other	**4.6**	3.2
	100.0	100.0

11 > EMPLOYEE FUTURE BENEFITS
(continued)

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 $83 million and $78 million at December 31, 2004 and 2003 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, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are fully 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 $80 million to its pension plan in respect of 2004, payable one month in arrears, and will contribute a further $80 million in respect of 2005 and 2006, all of which is required to satisfy minimum funding requirements. All of the contributions are expected to be in the form of cash. The Company has previously not been required to contribute to the pension plan because the contribution level, which was established from the last actuarial valuation at December 31, 2000, indicated that the plan had a surplus. Contributions after 2006 will be based on actuarial valuations as at 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 2004, 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 $110 million in 2004 (2003- $35 million).

Year ended December 31 (Canadian dollars in millions)	Pension 2004	Pension 2003	Employee Future Benefits other than Pension 2004	Employee Future Benefits other than Pension 2003
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	**4,323**	4,114	**897**	820
Current service cost	**76**	69	**24**	23
Interest cost	**254**	264	**54**	52
Benefits paid	**(232)**	(238)	**(36)**	(35)
Plan amendments	**—**	11	**—**	—
Net actuarial loss	**441**	103	**27**	37
Accrued benefit obligation, December 31	**4,862**	4,323	**966**	897
Change in plan assets				
Fair value of plan assets, January 1	**3,939**	3,607	**—**	—
Actual return on plan assets	**458**	562	**—**	—
Benefits paid	**(232)**	(238)	**—**	—
Employer's contributions	**74**[1]	—	**—**	—
Employees' contributions	**16**	14	**—**	—
Administrative expenses	**(12)**	(6)	**—**	—
Fair value of plan assets, December 31	**4,243**	3,939	**—**	—
Funded status				
(Unfunded benefit obligation)	**(619)**	(384)	**(966)**	(897)
Unamortized net actuarial losses	**1,128**	940	**271**	262
Unamortized past service costs	**25**	28	**6**	7
Deferred pension asset (accrued benefit liability)	**534**	584	**(689)**	(628)
Less: current portion	**—**	—	**35**	31
Deferred pension asset (long-term liability)	**534**	584	**(654)**	(597)
Components of net periodic benefit cost				
Current service cost, net of employee contributions	**60**	55	**24**	23
Interest cost	**254**	264	**54**	52
Actual return on plan asset net of expenses	**(446)**	(556)	**—**	—
Actuarial loss	**441**	103	**27**	37
Plan amendment	**—**	11	**—**	—
Other	**—**	—	**(1)**	—
Costs arising in the period	**309**	(123)	**104**	112
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	**174**	297	**—**	—
Actuarial gain	**(362)**	(7)	**(11)**	(21)
Plan amendments	**3**	(9)	**1**	1
Net periodic benefit cost[2]	**124**	158	**94**	92
Charged to results of operations[2]	**22**	—	**56**	55

[1] In January, 2005, the Company made a contribution of $7 million is respect of 2004.

[2] The Company follows the cash basis of accounting. During 2004, pension costs of $81 million (2003 - $nil) were attributed to labour, of which $22 million (2003 - $nil) was charged to operations, $31 million (2003 - $nil) was capitalized as part of the cost of fixed assets, and $28 million (2003- $nil) was attributed to a regulatory asset.

11 > EMPLOYEE FUTURE BENEFITS
(continued)

	Pension		Employee Future Benefits other than Pension	
Year ended December 31 (Canadian dollars in millions)	**2004**	2003	**2004**	2003
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	**—**	—	**124**	123
Service cost and interest cost	**—**	—	**11**	10
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	**—**	—	**(108)**	(110)
Service cost and interest cost	**—**	—	**(9)**	(8)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	**7.00%**	7.25%	**—**	—
Weighted-average discount rate	**6.00%**	6.50%	**6.18%**	6.67%
Rate of compensation scale escalation (without merit)	**3.25%**	3.50%	**3.25%**	3.50%
Rate of cost of living increase	**2.25%**	2.50%	**2.25%**	2.50%
Average remaining service life of employees (years)	**12**	12	**11**	12
Rate of increase in health care cost trend[3]	**—**	—	**4.40%**	4.40%
For accrued benefit obligation, December 31:				
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%
Rate of increase in health care cost trend[4]	**—**	—	**4.40%**	4.40%

[3] 9.00% in 2004 grading down to 4.40% per annum in and after 2014 (2003 – 9.70% grading down to 4.40% per annum in and after 2014).

[4] 8.50% in 2005 grading down to 4.40% per annum in and after 2014 (2003 – 9.00% in 2004 grading down to 4.40% per annum in and after 2014).

12 > ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	**2004**	2003
Environmental liabilities, January 1	**83**	160
Interest accretion	**5**	8
Expenditures	**(15)**	(21)
Revaluation adjustment **(Note 8)**	**16**	(64)
Environmental liabilities, December 31	**89**	83
Less: current portion	**(15)**	(14)
	74	69

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2004 and in total thereafter are as follows: 2005 - $15 million; 2006 - $16 million; 2007 - $15 million; 2008 - $15 million; 2009 - $13 million; and thereafter - $39 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.

13 > 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 2004, preferred dividends in the amount of $18 million (2003 - $18 million) and common dividends in the amount of $247 million (2003 - $226 million) were declared.

Earnings per Share

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

14 > RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. 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 2004 includes $1,228 million (2003 - $1,255 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 2004 includes $21 million (2003 - $21 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2004 includes $127 million (2003 - $127 million) related to this program, of which $1 million (2003 - $1 million) was paid to local distribution companies in respect of annexation agreements.

Hydro One purchased power from the IESO administered spot market in the amount of $1,987 million in 2004 (2003 - $1,872 million).

Hydro One has service level agreements with the other successor corporations. These services include field and engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $11 million (2003 - $13 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 2004 and 2003.

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)	**2004**	2003
Accounts receivable	**120**	112
Accounts payable and accrued charges	**(247)**	(195)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $200 million (2003 - $149 million).

15 > 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)	2004	2003
Accounts receivable (increase) decrease	**(91)**	30
Materials and supplies (increase) decrease	**(2)**	10
Accounts payable and accrued charges increase	**10**	44
Accrued interest increase (decrease)	**6**	(15)
Long-term accounts payable and accrued charges (decrease) increase	**(9)**	5
Employee future benefits other than pension increase	**57**	57
Other	**(4)**	7
	(33)	138
Supplementary information:		
Interest paid	**285**	333
Payments in lieu of corporate income taxes	**207**	199

16 > 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.

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 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

16 > CONTINGENCIES
(continued)

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. The Company has requested particulars and further and better particulars of the claims, as did the other defendants. As a result of the particulars filed, the Attorney General for Canada brought various motions, which the Company supported, to strike out various claims and for better responses to the particular demands. In September 2003, the Court struck out the claims with leave to amend. Additionally, 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 integrity of the transmission system with the entire electricity system, which includes the method of generating power. Several defendants brought a motion for particulars of the allegations in the consolidated action in September 2004 and it was partially successful. To date, Hydro One has not filed a defense. 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.

17 >
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, 2004, and in total thereafter are as follows: 2005 - $107 million; 2006 - $105 million; 2007 - $103 million, 2008 - $100 million; 2009 - $96 million; and thereafter - $199 million.

Additionally, the outsourcing agreement with Inergi includes a risk sharing agreement involving either Hydro One or Inergi making a payment related to a future imbalance between pension fund assets and liabilities for transferred staff covered by the Inergi Pension Plan. The risk sharing agreement will be 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 $24 million equally over the next three 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, 2004, the Company provided prudential support, using a combination of bank letters of credit of $33 million (2003 - $35 million) and parental guarantees of $275 million (2003 - $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, 2004, Hydro One had bank letters of credit of $80 million (2003 - $69 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, 2004 and in total thereafter are as follows: 2005 - $6 million; 2006 - $5 million; 2007 - $4 million; 2008 - $3 million; 2009 - $3 million; and thereafter - $nil.

18 > SEGMENT REPORTING

Hydro One has three reportable segments:

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

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

Year ended December 31 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
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 regulatory recovery, financing charges and provision for payments in lieu of corporate income taxes	**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**
2003				
Segment profit				
Revenues	1,298	2,734	26	4,058
Purchased power	—	1,872	—	1,872
Operation, maintenance and administration	382	387	26	795
Depreciation and amortization	228	223	3	454
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	688	252	(3)	937
Financing charges				348
Income before provision for payments in lieu of corporate income taxes				589
Capital expenditures	289	292	16	597

December 31 (Canadian dollars in millions)	2004	2003
Total assets		
Transmission	**6,785**	6,589
Distribution	**4,845**	4,623
Other	**95**	94
	11,725	11,306

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

19 > COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2004 Consolidated Financial Statements.

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	**2004**	2003	2002	2001	2000
Statement of operations data					
Revenues					
Transmission	**1,262**	1,298	1,317	1,259	1,260
Distribution	**2,874**	2,734	2,682	2,158	1,703
Other	**17**	26	32	49	32
	4,153	4,058	4,031	3,466	2,995
Costs					
Purchased power	**1,987**	1,872	1,858	1,267	859
Operation, maintenance and administration[1]	**771**	795	832	824	863
Depreciation and amortization	**480**	454	411	384	348
	3,238	3,121	3,101	2,475	2,070
Regulatory recovery[2]	**91**	—	—	—	—
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,006**	937	930	991	925
Financing charges	**331**	348	353	350	340
Income before provision for payments in lieu of corporate income taxes	**675**	589	577	641	585
Provision for payments in lieu of corporate income taxes	**177**	193	233	267	207
Net income	**498**	396	344	374	378
Basic and fully diluted earnings per common share[3] (Canadian dollars)	**4,798**	3,779	3,258	3,562	3,182

December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	**6,785**	6,589	6,638	6,693	6,477
Distribution	**4,845**	4,623	4,694	4,416	3,434
Other	**95**	94	90	122	86
Total assets	**11,725**	11,306	11,422	11,231	9,997
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,262**	1,192	1,894	1,625	1,049
Long-term debt	**4,613**	4,539	3,938	4,079	3,972
Other long-term liabilities	**1,326**	1,284	1,451	1,533	976
Shareholder's equity					
Share capital[4]	**3,637**	3,637	3,637	3,637	3,759
Retained earnings	**887**	654	502	357	241
Total liabilities and shareholder's equity	**11,725**	11,306	11,422	11,231	9,997

Year ended December 31 (Canadian dollars in millions)	**2004**	2003	2002	2001	2000
Other financial data					
Capital expenditures					
Transmission	**432**	289	260	274	280
Distribution[5]	**288**	292	286	247	152
Other	**7**	16	24	45	14
Total capital expenditures	**727**	597	570	566	446
Ratios					
Net asset coverage on long-term debt[6]	**1.88**	1.86	1.90	1.88	1.90
Earnings coverage ratio[7]	**2.70**	2.43	2.35	2.53	2.37
Operating statistics					
Transmission					
Units transmitted *(TWh)*[8]	**153.4**	151.7	153.2	146.9	146.9
Ontario 20-minute system peak demand *(MW)*[8]	**25,204**	24,849	25,629	25,269	23,428
Ontario 60-minute system peak demand *(MW)*[8]	**24,979**	24,753	25,414	25,239	23,301
Total transmission lines *(circuit-kilometres)*	**28,643**	28,621	28,492	28,387	28,490
Distribution					
Units distributed to Hydro One customers *(TWh)*[8]	**28.5**	27.9	27.1	21.3	17.6
Units distributed through Hydro One Lines *(TWh)*[8, 9]	**44.8**	44.7	45.1	41.3	40.2
Total distribution lines[10]	**123,781**	123,297	122,830	122,399	113,880
Customers	**1,258,925**	1,238,748	1,219,614	1,193,089	957,474
Total regular employees[11]	**4,118**	3,967	3,933	4,815	4,468

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

[2] As a result of the oral and written evidence submitted by Hydro One, the OEB issued a ruling on December 9, 2004, 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.

[3] On March 31, 2000, Hydro One issued to the Province 12,920,000 5.5% cumulative preferred shares and 99,990 common shares.

[4] In December 2001, Hydro One and the Province settled a post-closing adjustment for $122 million, related to the actual net assets acquired from Ontario Hydro, through shareholder's equity.

[5] Capital expenditures exclude $468 million in 2001 and $23 million in 2000 associated with acquisitions of local distribution companies.

[6] 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).

[7] 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. In respect of 2004, the earnings coverage ratio, exclusive of the regulatory recovery, is 2.46.

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

[9] 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 Ontario Power Generation.

[10] Distances for distribution lines are recorded as circuit kilometers for Hydro One Networks and in total wire length in kilometers for Hydro One Brampton.

[11] On March 1, 2002, approximately 770 regular employees were transferred to Inergi (see Note 17).

SENIOR MANAGEMENT TEAM

Left to right

Nairn McQueen
Vice-president,
Engineering and
Construction Services

Rick Kellestine
Vice-president,
Lines and
Forestry Services

Myles D'Arcey
Vice-president,
Stations and
Remote Communities

Beth Summers
Chief Financial Officer

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

Tom Goldie
Senior Vice-president,
Corporate Services

Tom Parkinson
President and
Chief Executive Officer

Michelle Morrissey O'Ryan
Vice-president,
Health, Safety and
Environment

Geoff Ogram
Vice-president,
Strategy and
Development

Les McKay
Vice-president,
Executive Office

Steve Dorey
Vice-president,
External Relations

Laura Formusa
General Counsel and
Secretary

Absent: **Dave Barrie,** Senior Vice-president, Asset Management

BOARD OF DIRECTORS

Rita Burak

Chair of the Board of Directors, Hydro One Inc.

W. Geoffrey Beattie

President, The Woodbridge Company Limited

Sami Bébawi

Executive Vice President, Office of the President, President, Socodec Inc., SNC–Lavalin Group Inc.

Murray J. Elston

President and CEO, Canadian Nuclear Association

Dr. Murray B. Frum

Chair and CEO, Frum Development Group

Don MacKinnon

President, Power Workers' Union

Eileen A. Mercier

Corporate Director

Tom Parkinson

President and CEO, Hydro One Inc.

Hon. Bob Rae

Partner, Goodmans LLP

Kenneth D. Taylor

Chair, Taylor and Ryan Inc.

Blake Wallace, Q.C.

Vice President and Director, Murray & Company

Adam Zimmerman

Corporate Director

BOARD COMMITTEES

Audit and Finance Committee

The Audit and Finance Committee is responsible for overseeing the accounting and financial reporting practices of the Company and the auditing of its financial statements. In addition, the committee is responsible under the terms of its charter for making recommendations to the Board of Directors regarding the financing plans, risk management strategies and objectives of the Company. The committee reviews the interim and annual consolidated financial statements and related management discussion and analysis disclosures, as well as financial statements in any offerings of our debt securities as required by securities regulatory authorities. The committee also oversees the establishment and maintenance of the Company's internal audit procedures and controls, selects and oversees work of the external auditors and advises the Board on its auditing practices and procedures to ensure that the Company is in compliance with the laws and regulations that apply to it as well as its own policies. The committee met five times in 2004.

MEMBERS: Eileen Mercier, *Chair*. W. Geoffrey Beattie, Murray Elston, Dr. Murray Frum, Adam Zimmerman

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, annually reviews the mandates of each committee of the Board, 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 2004.

MEMBERS: Adam Zimmerman, *Chair*. Rita Burak, Eileen Mercier, Hon. Bob Rae, Blake Wallace

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 nine times in 2004.

MEMBERS: Hon. Bob Rae, *Chair*. W. Geoffrey Beattie, Dr. Murray Frum, Blake Wallace

Regulatory and Environment Committee

The Regulatory and Environment Committee is responsible for ensuring compliance with all applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures, reviews the Company's proposals for rate applications, formulates contingency plans and reviews compliance actions and reports. The committee met five times in 2004.

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

Health and Safety Committee

The Health and Safety Committee is responsible for 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 2004.

MEMBERS: Don MacKinnon, *Chair*. Sami Bébawi, Kenneth Taylor, Adam Zimmerman

CORPORATE INFORMATION

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Auditors

Ernst & Young LLP

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Hydro One Inc.

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