UNDERTAKING JT3.1

Undertaking

TO PROVIDE RESULTS OF EACH OF THE METRICS ON THE CORPORATE SCORECARDS REFERRED TO IN L-6.6-15 SEC-3.

Response

Attached to this response as attachments 1-3 are the corporate scorecard results for 2013, 2014, and 2015. Results for 2016 are not yet available.

Corporate 2013 Balanced Scorecard – Forecast

(Revised Jan20, 2014)

Weight	Key Performance Indicators	Threshold	Target	Maximum	Projected Y/E Results	YE Score	Weighted Score
10%	**Safety, Environment, Reliability and Code of Conduct** Deliver front-line/core services						
10%	• **AIR:** All Injury rate (Target = CEA Top Quartile)	1.57	0.89	0.36	**0.61**	**1.26**	**0.00**
10%	• Safety focus areas: o Improvement in the area of Work Protection Code o Continued focus on Situational Awareness • No significant events that impact OPG's reputation	As determined by CEO			**Below Threshold**	**0.0**	
30%	**Financial Performance -** Reduce costs & improve OPG financial health						
7%	EBITDA ($M) (-10%, +15%)	948	1,053	1,211	**$1,302M**	**1.50**	**0.11**
5%	Headcount – Ongoing Operations (+173, -252)	10,550	10,377	10,125	**10,048**	**1.50**	**0.08**
15%	Operating OM&A expenditures ($M) (+5%, -10%)	2,735	2,605	2,344	**$2,491M**	**1.22**	**0.18**
3%	Support Services Operating OM&A expenditures ($M) (+5%, -10%)	643.7	613	551.7	**$575M**	**1.31**	**0.04**
35%	**Fleet Operating Performance -** Control costs while delivering front-line/core services						
25%	Nuclear: TWh	45.99	47.99	48.99	**44.69**	**0.0**	**0.0**
2.5%	Thermal: Start Guarantee rate	85%	94%	97%	[redacted]		
7.5%	Hydro: Availability (%)	89.5%	91.6%	93.5%	**91.6%**	**1.00**	**0.08**
25%	**Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services						
8%	• OPG Business Transformation Strategy	Meet project milestones and measures specific to each project – See Attached				**1.00**	**0.08**
4%	• Niagara Tunnel					**1.25**	**0.05**
4%	• Lower Mattagami					[redacted]	
2%	• Atikokan conversion						
7%	• Nuclear Refurbishment					**1.06**	**0.07**
100%							**0.77**

These measures form the basis on which our overall corporate performance will be assessed but the scores against these measures and overall Corporate score are not absolute. The Board and President reserve the right to determine the Corporate Score. In exercising their discretion, the Board and President may choose to make adjustments to the Corporate Score or individual scorecard items.

2013 Corporate Balanced Scorecard – Forecast Project Performance Measures

2013 Corporate Balanced Scorecard – Project Performance Measures (*Revised Jan 20, 2014*)	Threshold	Target	Maximum	Projected Y/E Results	YE Score (Below /Target/Above)
Business Transformation					**1.0 – Adjusted by CEO**
A. Fully Implement the Centre Led Organization (30%)	Both results are at or better than Threshold (Note 1)	Both results are at or better than Target (Note 1)	Both results are at or better than Maximum (Note 1)		
1. ELT acceptance of the Deployment Impact Assessment (15%)	May 31	April 30	March 31 plus CEO assessment of cross-BU collaboration	Actual completion date - March 20th, 2013 CEO assessment confirmed max	**1.25**
2. ELT acceptance of Deployment Readiness Assessment (15%)	June 30	May 31	April 30 plus CEO assessment of cross-BU collaboration	Completed May 8th, 2013. CEO assessment confirmed target	
B. **Transforming the way we work (50%):**					
1. Key transformational initiatives meet the key milestones indicating progress on transformation. (30%) * *Key transformational initiatives identified by Builders' input of 1 or 2 key BT initiatives for each BU*	20 of 30 milestones met as scheduled	25 of 30 milestones met as scheduled	All 30 milestones met as scheduled	29 completed as scheduled.	**1.4**
2. Business Transformation is embedded in our business practice and culture. a) Business planning appropriately reflects BT initiatives and goals (10%)	CEO Assessment			CEO Assessment Confirmed as target	**1**
b) Transition plan in place to reduce oversight and integration aspects of BT and move key support functions of BT team back to functions and support BU's as business as usual (i.e. change mgmt, HR support) (10%)	Transition Plan in place for 2014 by Dec. 31, 2013	Minimized oversight of BT by Dec. 31, 2013	Transition complete by Dec. 31, 2013	Threshold - 2014 Transition plan reviewed with ELT and approved by ELT Executive sponsor on Dec 19th 2013.	**0.5**
C. **Effectively managing attrition (20%)**					
Target represents the 2013 Business Plan headcount from ongoing operations (excludes DNNP and Refurbishment)	10,550	10,375	10,125	Current finance forecast of YE headcount: 10,048	**1.5**

2013 Corporate Balanced Scorecard – Project Performance Measures (*Revised Jan 20, 2014*)	**Threshold**	**Target**	**Maximum**	**Projected Y/E Results**	**YE Score** (Below /Target/Above)
Niagara Tunnel	Both results are at or better than Threshold (Note 1)	Both results are at or better than Target (Note 1)	Both results are at or better than Maximum (Note 1)		
A. Forecasted In-Service Date	June 30, 2013	May 15, 2013	March 31, 2013	9 Mar2013 - Max	**1.25 (Based on Cost)**
B. Forecasted Final Cost	$1.55B	$1.5B	$1.45B	***$1.475B Above Target***	
Lower Mattagami	All results are at or better than Threshold (Note 1)	All results are at or better than Target (Note 1)	All results are at or better than Maximum (Note 1)		
A. Little Long – G3 Unit in-service	Projected 1-Mar-2014 (Note 2)	31-Dec-2013	1-Nov-2013	[redacted]	
B. Smoky Falls - Volume (m3) of concrete placed at year-end (LTD)	120,000	125,000	130,000		
C. Harmon – Turbine installed	31-Dec-2013	15-Oct-2013	15-Aug-2013		
D. Powerhouse Concrete Pour Complete	Scrollcase walls complete 31-Dec-2013	Scrollcase walls & soffit complete 31-Dec-2013	Scrollcase walls & soffit complete 1-Dec-2013		
Atikokan Conversion to Biomass Schedule on track (I/S Q1 2014)	All results are at or better than Threshold (Note 1)	All results are at or better than Target (Note 1)	All results are at or better than Maximum (Note 1)		
Surge Bin Completion	12-Dec-2013	12-Nov-2013	12-Oct-2013	[redacted]	
Storage Silo Erection	7-Nov-2013	7-Oct-2013	7-Sep-2013		
On track to perform First Fire on Gas	Projected31-Jan 2014	15-Dec-2013	1-Nov-2013		
Project Estimated Costs on track	Projected $ 169.5M	$164.4M	$159.3M		
Darlington Refurbishment	All results are at or better than Threshold (Note 1)	All results are at or better than Target (Note 1)	All results are at or better than Maximum (Note 1)		
A. Progression of Strategic Contracts (Fuel Handling, Steam Generator, and Turbine Generators) - adherence to schedule (SPI)	0.90	1.00	1.05	1.04 – Close to Maximum	**1.06 (based on Containment Filtered Venting System)**
B. Containment Filtered Venting System (BCS approved and contract for detailed design awarded)	Sep 30	Aug 31	July 31	***Complete Aug 27- Better than Target***	
C. Submission of Global Assessment Report and Integrated Implementation Plan to CNSC	Dec 31	Dec 2	Nov 15	Submission to the CNSC on November 15, 2013. (Maximum)	

2013 Corporate Balanced Scorecard – Project Performance Measures (*Revised Jan 20, 2014*)	**Threshold**	**Target**	**Maximum**	**Projected Y/E Results**	**YE Score** (Below /Target/Above)
D. Start of Mock-up Construction (date)	July 30	July 15	June 15	Achieved > 1 month ahead of plan. (Maximum)	
E. Scope Definition—All Approve Darlington Scope Requests <= Health of Scope 20 (Note 2)	Dec 31	Dec 2	Nov 15	All approved Darlington Scope Requests <=Health of Scope 20 achieved by November 15 (Maximum)	

Notes:

1. For these projects with multiple components, the entire project takes the score of the lowest performing component
    - If any of the tasks are below Threshold, the project does not meet Threshold
    - All tasks must be at or better than target to achieve target. If any task is below target, the project takes the score of the lowest performing task.
    - All tasks must be at or better than maximum to achieve maximum. If any task is below maximum, the project takes the score of the lowest performing task.

2. Exceptions (approved by the EVP Nuclear Projects) are allowed for the following: Scope resulting from planned inspections or analysis scheduled during or after 2013, i.e. scope resulting from scheduled inspections in the 2015 VBO outage. Any new scope approved by: The Darlington Refurbishment Scope Review Board during or after 2013. Any new scope resulting from the CNSC's review and approval of the EA or ISR. "Approved" Darlington Scope Requests require approval by the Darlington Refurbishment Scope Review Board.
    - The following are the Health of Scope definitions (note the lower the score, the scope is better defined):
        - 90 Scope will not be executed in Nuclear Refurbishment, DSR will be removed pending PSRB approval
        - 60 Pure engineering or procedures with no likely field work (i.e. provide CNSC with reports, update procedures, etc)
        - 50 Assessment is required to build a report for analysis
        - 40 Analyze the completed report to determine actions / path forward
        - 30 Actions to implement selected, may be a component strategy across many systems
        - 20 Work is known at the system or project level but not component
        - 10 Work is known at the component / MEL level
        - 5 DSR is adequately known such that it is ready for Work Order to be input on all Units
        - 4 All Work Orders input for DSR on all applicable Units or all work completed for DSR.

2014 Corporate Balanced Scorecard – Year-End Results							
Weight	**Key Performance Indicators**	**Threshold**	**Business Plan**	**Stretch Target**	**Y/E Results**	**Score**	**Weighted Score [1]**
10%	**Safety, Environment, Reliability and Code of Conduct -** Deliver front-line/core services						
10%	**AIR:** All Injury rate (Target = CEA Top Quartile)	1.69	0.89	0.36	**0.36**	**1.50**	**0.10**
10%	• Safety focus areas: o Improvement in the area of Work Protection Code o Continued focus on Situational Awareness o Nuc and HT, public, employee, and operational safety • No significant events that impact OPG's reputation	As determined by CEO			**Business Plan**	**1.00**	
50%	**Financial Performance -** Reduce costs & improve OPG financial health						
15%	EBT ($M)	300	500	700	**$749**	**1.50**	**0.23**
10%	Operating OM&A Expenses – Total OPG ($M)	2,600	2,475	2,325	**$2,335**	**1.47**	**0.15**
5%	Non-Electricity Generation Margin ($M)	325	350	400	**$397**	**1.47**	**0.07**
15%	Production – Total OPG adjusted for Hydro SBG (TWh)	80.6	82.4	84.2	**83.3**	**1.25**	**0.19**
5%	Business Transformation: 2014 headcount from ongoing operations (excluding Refurbishment).	9900			**9,489**	**1.00**	**0.05**
40%	**Long Term Energy Plan and Capital Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services						
15%	**Nuclear Refurbishment Progress (Number of deliverables from Table A, attached)**	4	13	16	**11**	**0.50**	**0.08**
10%	**Pickering License hold point removed (210K hr)**	Prior to unit 6 exceeding 210,000 full power hours of operation.			**Achieved**	**1.00**	**0.10**
10%	**Lower Mattagami** (Units in-service)	1	2	3	**5**	**1.50**	**0.15**
5%	**Atikokan – Commercial Operation**	Achieved by year-end 2014			**July 24/14**	**1.00**	**0.05**
100%							**1.16**

Note 1: Numbers may not add due to rounding

Table A: Darlington Refurbishment Progress		
Threshold: Deliverables 1-4	Business Plan: Deliverables 1-13	Stretch Target: Deliverables 1-16
Deliverable	**Description**	
1	Re-tube & Feeder Replacement Mock-up - Available for Use	
2	Fuel Handling - Dummy Fuel Bundles and Flow Reduction Orifice Bundles Mock-up Units Delivered	**Threshold**
3	D20 Storage Facility - Caisson Installation Complete	
4	Vehicle Screening Facility - Available for Service	
5	Holt Road Interchange - Site Preparation Complete	
6	Re-tube & Feeder Replacement - Mock-up Toolset Delivered	
7	Global Assessment Report & Integrated Implementation Plan Approved by CNSC	
8	Water & Sewer System - Available for Service	
9	Electrical Power Distribution System - 44kV Distribution Station DS5 Installation Complete	**Business Plan**
10	3rd Emergency Power Generator - Buried Services Relocation Complete	
11	Re-tube & Feeder Replacement Island Annex - Buried Services Relocation Complete	
12	Refurb Project Office - Structural Steel Erected	
13	Operations Support Building Refurbishment - New Cladding/Windows Installed	
14	Re-tube & Feeder Replacement Unit 2 Toolset - Single Fuel Channel & Spacer Removal Tools and D2O Vacuum Drying Systems Delivered	**Current Baseline Target - September 4, 2015**
15	Auxiliary Heating System - Boilers Delivered	**Current Baseline Target- January 30, 2015**
16	D20 Storage Facility - Excavation Complete	**Current Baseline Target - February 2015**

2015 Corporate Balanced Scorecard – Year-End Results as @ February 22, 2016							
Weight	**Key Performance Indicators**	**Threshold**	**Business Plan**	**Stretch Target**	**Y/E Results**	**Score**	**Weighted Score (1)**
10%	**Safety, Environment, Reliability and Code of Conduct -** Deliver front-line/core services						
10%	**AIR:** All Injury rate (Target = CEA Top Quartile)	1.20	0.69	0.25	**0.39**	**1.34**	**0.12**
	Safety focus areas: • Improvement in the area of Work Protection performance with emphasis on reducing human errors • Fostering a stronger employee health culture with a focus on enhanced support and mental health training. No significant events that impact OPG's reputation	As determined by CEO				**1.0**	
50%	**Financial Performance -** Reduce costs & improve OPG financial health						
15%	EBT - excl. nuclear waste management segment ($M)	400	600	800	**$673**	**1.18**	**0.18**
15%	Operating OM&A Expenses – Total OPG ($M)	2,580	2,455	2,305	**$2,400**	**1.18**	**0.18**
15%	Production – Total OPG adjusted for SBG (TWh)	78.3	80.5	82.6	**78.45**	**0.53**	**0.08**
5%	Headcount from ongoing operations (excluding Refurbishment).	9,491	9,264	9,084	**9,010**	**1.50**	**0.08**
40%	**Long Term Energy Plan and Capital Project Performance -** Support Ontario's Long Term Energy plan and deliver front-line/core services						
5%	Darlington Refurbishment - Campus Plan D2O Storage Facility - Dyke Construction Complete	31-Dec	30-Nov	31-Oct	**23-Dec**	**0.63**	**0.03**
5%	Darlington Refurbishment - Campus Plan - 3rd Emergency Power Generator - Building complete and Generator in-place	31-Dec	30-Nov	31-Oct	**31-Dec**	**0.5**	**0.03**
10%	OPG Board Approval of Refurbishment Budget (RQE)	Before Year End			**November**	**1.00**	**0.10**
5%	Refurbishment Project Cost ($M) - Cumulative to the end of 2015	$2,784	$2,732	$2,628	**$2,662**	**1.34**	**0.07**
5%	Darlington Fuel Handling Reliability - Ready for on Reactor Trial (SARF – Service Area Rehearsal Facility)	Universal Carriers Delivered Before Year End	Threshold plus SARF In-Service Before Year End	Universal Carrier Commissioned on SARF Before Year End	**Stretch Target**	**1.50**	**0.08**
5%	Darlington Relicensing (License Term in years)	5	8	13	**10**	**1.20**	**0.06**
5%	Darlington VBO (Duration - Days)	47.5	43.5	39.5	**46.8**	**0.59**	**0.03**
100%							**1.01**

Note 1: Numbers may not add due to rounding

UNDERTAKING JT3.2

Undertaking

TO PROVIDE A STEP-BY-STEP BREAKDOWN OF HOW CALCULATIONS IN EX. L-6.6-15 SEC-083, PART B WERE ARRIVED AT. ALSO TO ADVISE IF ANY ADJUSTMENTS WERE MADE TO THE METHODOLOGY USED IN EB-2013-0321, UNDERTAKING J9.11 TO DETERMINE THAT RESPONSE TO THIS RESPONSE.

Response

Attachment 1 provides a breakdown of the calculations provided in Ex. L6.6-15 SEC-083, part (b).

The approach taken is mostly consistent with the methodology used in EB-2013-0321 Undertaking J9.11, with the following noted differences. The cost impacts reflected in J9.11 were estimated wholly by OPG; and, in providing a response to Ex. L-6.6-15 SEC-083, Willis Towers Watson estimated the total OPG cost impacts, and OPG calculated the percentage of the impacts attributable to the Nuclear regulated business as shown in Attachment 1.

Group	Segment	WTW Estimate	Determination of Regulated Portion Based on Organizational Details *(Prorated costs provided by WTW to each organization, and then used 2K FTE proportions to identify that which is assocaited with Regulated Nuclear, including both Direct (Nuclear Org) & Allocated (Corp Group) costs.*						
					OPG Headcount by Org (Apr 1 2015)	% Nuclear Regulated (from Appendix 2K Data)		% of Headcount	Estimate of Nuclear Regulated Costs
		TDC Costs Above (Below) 50thP ($M)	Nuclear Org	Corporate Groups		Nuclear Org	Corp Groups		
		A	B	C	D	E	F	G = (B x E + C x F) / D	H = A x G
Mgmt	Utility	(13.8)	358	81	532	99%	71%	78%	(10.7)
	Nuclear Authorized	(4.0)	33	6	39	100%	100%	100%	(4.0)
	General Industry	0.6	94	386	491	99%	71%	75%	0.5
	Mgmt Sub-Total	(17.1)	485	473	1,062	99%	71%	77%	(14.2)
Society	Utility	13.4	1,630	302	2,235	100%	75%	83%	11.1
	Nuclear Authorized	(1.9)	77	34	111	100%	100%	100%	(1.9)
	General Industry	7.4	118	429	572	100%	75%	77%	5.7
	Society Sub-Total	18.9	1,825	765	2,918	100%	75%	82%	14.9
PWU	Utility	14.1	2,711	191	3,754	100%	90%	77%	10.8
	Nuclear Authorized	3.9	255	0	255	100%	100%	100%	3.9
	General Industry	17.6	621	680	1,524	100%	90%	81%	14.2
	PWU Sub-Total	35.6	3,587	871	5,533	100%	90%	79%	28.9
Total		37.4	5,897	2,109	9,513			80%	29.6

UNDERTAKING JT3.3

Undertaking

TO DETERMINE SPECIFICALLY HOW HACKETT WOULD PROVIDE INSTRUCTIONS IN TERMS OF HOW TO EXTRACT THE DATA TO DETERMINE THE NUMBER OF END USERS.

Response

Reference: Ex. F3-1-1, Attachment 1, p. 6

OPG followed the Hackett Group's project approach that included training on the Hackett Group's bencmarking taxonomy. This training involved discussions on the application of the definition of an IT End User. Hackett concluded that OPG's local-area network identification number (LANID) meets the definition of IT End User under the benchmarking taxonomy. LANID account is assigned to an individual (either an employee or contractor), granting him or her access to OPG's IT infrastructure in accordance to his or her business function. The LANID information is externally generated by New Horizon System Solutions, OPG's external IT services provider.

UNDERTAKING JT3.4

Undertaking

TO PROVIDE THE DOCUMENTS LISTED IN EXHIBIT NO. KT3.1

Response

Please find attached the following documents listed in KT3.1:

Att. #	Board Report	Internal Audit Engagement
1.	AFC 2014 Q2	AG Management Actions Follow-Up Activity
2.	AFC 2014 Q4	Nuclear Liability Cost Estimate
3.	AFC 2015 Q2	Corporate Strategy & Planning Process
4.	AFC 2015 Q3	Pension and OPEB Audit
5.	AFC 2015 Q4	Nuclear Liability Cost Estimate
6.	ARC 2016 Q1	Compensation - Follow-up on 2013 Auditor General Findings
7.	ARC 2016 Q1	Ontario Energy Board ("OEB") Rate Application
8.	ARC 2016 Q2	Business Transformation Performance
9.	ARC 2016 Q3	SMART Objectives – Follow up

The other documents listed in KT3.1 are filed in response to JT1.8.

KT3.1 list two documents titled "Financial Controls for Darlington Refurbishment Project." These documents are duplicates. The single responsive document is filed as Attachment 9 to JT1.8.

Each attachment is marked "confidential." However, OPG has determined that these attachments are non-confidential, except where specifically identified in Attachment 1. Attachment 1 is being filed in accordance to the Ontario Energy Board's Practice Direction on Confidential Filings.

ONTARIO POWER GENERATION

OPG CONFIDENTIAL

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MEMORANDUM

May 21st, 2014

Barb Keenan
SVP People & Culture

Background

In December 2013, the Auditor General (AG) of Ontario released a report on OPG's Human Resources which had a number of findings and six specific recommendations for OPG to address. OPG Senior Management analyzed the AG report and assigned selected findings to a number of ELT members to address. Action plans were drafted, key milestones were developed and individuals were assigned to take responsibility for actions associated with each finding.

One of the overall OPG management actions developed to address the AG findings was for Internal Audit (IA) and/or an independent third party to perform a review of management actions upon their completion. IA took the opportunity to conduct a review of the status of management actions related to the recruitment process in conjunction with its previously scheduled 2014 audit of the Recruit, Select and Hire process.

Objective & Scope

The objective of this review was to verify completion of management action plans, as reported by management in the, "OPG Actions in Response to 2013 Auditor General Report on Human Resources" document, and the underlying supporting documentation.

The scope of this review included management actions pertaining to recruitment, as listed in the table below. Only underlying milestones (associated with the action plans below) declared by management as "complete" as of March 24, 2014 were reviewed as part of this engagement. Milestones under the purview of OPG business units/functions outside of recruitment, e.g. supply chain, were excluded from this review and if required, will be followed up at a future date.

Finding	AG Issue Description Excerpts	Management Action Plans
1b	Staff size has reduced by 8.5% since 2005 but there has been an increase by 58% in senior staff/executive ranks (VPs 74%, Directors 47%) in the same period, with the "most obvious	#2 - Hiring of all Director and above positions (Bands A-F) require CEO approval. Two executive positions have been eliminated by consolidation in Q4 2013 (EVP and Deputy CNO roles).

	period, with the "most obvious jump in 2012 during BT".	
1d	Approximately 700 groups (1,400 employees over 10% of total staff) reside at the same address indicating they were family members. Four employees offered jobs although never appearing on an interview list etc.	#1 - Amend Code of Conduct to clarify expectations regarding hiring policies. Failure to follow policy will result in disciplinary action up to and including termination. #2 - Centralize hiring records. #3 - Centralize OPG's recruitment function to improve process efficiency and improve controls and compliance with the hiring process. #4 - Establish standards and develop education/support materials to aid managers in complying with the hiring policies. #5 - Conduct compliance reviews for both internal and external vacancies starting Q1 2014 #6 - All 700 groups have been analyzed to ensure a valid hiring process was followed.
3a	In 2012, 120 of 1,700 temporary and contract staff had formerly been regular employees. Almost all of them were rehired shortly after leaving OPG. Some of them continued to receive significant amounts in allowances and AIP awards, and some had already drawn commuted value of their pensions	#1 & #3- Conducted a policy review for hiring retirees on a temporary basis. A business rationale is required with approval by the Business Unit Leader and the Senior Vice President, People & Culture. OPG will implement a policy of not hiring retirees for at least twelve months after retiring from OPG.

Results of the Review

This engagement identified the following:

- Milestones were declared by management as complete prematurely, while documentation continued to be in draft form, and processes had yet to be fully implemented. Clear criteria that define completion for each milestone or action plan have not been defined, allowing for multiple interpretations of the status of each action plan or milestone.
- There was lack of well documented assumptions made during the analysis of the 700 groups of employees identified by the AG who reside at the same postal address.
- One instance of a hiring approval form for an executive was authorized by the required approvers after the effective date of the promotion.

Please refer to Appendix A for the summary of observations.

Internal Audit would like to take this opportunity to thank People and Culture management and staff for their cooperation during this review.

Approved By:

Michael Braude
(Acting) VP Assurance & Chief Audit Executive

cc:

Tom Mitchell
Chris Ginther
Scott Martin
Glenn Jager
Mike Martelli
Kerry Tompson
Jaffar Husain

Appendix A – Summary of Observations

#	Finding	Recommendation	Management Action Plan
1	**Progress reported does not reflect completion status**		
	In reviewing documentation evidencing completion of actions/milestones and through discussion with recruitment staff, it was noted that several milestones declared as "complete" were not entirely complete as of the time of this review. Various elements were not yet finalized and/or implemented within the new, centralized recruit, select and hire process, including the following: • **Documentation** –Milestones for introducing self-help tools, guides and templates, upgrading the intranet, revamping education materials and templates, and developing communication plans to HRBP's and line managers were marked as complete in the March 2014 updated tracking sheet, but were not fully implemented at the time of the review in March. Subsequent follow up noted the following: ▪ The hiring manager guides were in draft form, and were not available on the intranet at the time of this review. As of April 1, 2014, the hiring manager guides were finalized and made available on the intranet. ▪ The candidate and resume summary matrices templates were not available on the intranet at the time of the review. As of April 1, 2014, the matrices were made available on the intranet. ▪ At the time of this review, the communication plan of the documentation retention changes to line managers and HRBP's had yet to be finalized. Per discussion with management, as of April 1, 2014, the line managers - started to receive an email with the hiring guide after a job is posted in Taleo documenting the new documentation retention requirements, as part of the new hiring process. The hiring managers started to receive a follow up call from an HR services centre representative to ensure that they understand the new requirements and to answer any questions the hiring manager may have. This process is documented in the hiring manger's guide, which was live on the recruitment and resourcing intranet page as of April 1, 2014. The HRBP's were notified of the new documentation retention changes through conference calls that took place in early April 2014. • **Processes** – New processes for centralizing retention of hiring records and performing compliance reviews for internal and external vacancies were declared as completed.	It is recommended that Management perform the following: • Expand action plans to include description of the deliverables and criteria which define completion for each individual action plan, and update target completion dates as required. • Only declare completion of milestones and action plans when completion criteria established and deliverables are achieved 100%.	<u>Action Plan(s):</u> • As of April 1, 2014 the action committed to by Q1 timeline are complete. Due to ongoing modifications that became evident when rolling out to the user community in "beta" these forms were revised. Going forward, we will only declare completion when all established completion requirements are met. • As noted the committed actions are complete and effective for the Q1 operationalization. • All tools and templates were finalized as of April 1, 2014. No further actions are required. <u>Owner:</u> Nirav Patel <u>Target Completion Date:</u> Complete

#	Finding	Recommendation	Management Action Plan
	▪ At the time of the review, the process for centralizing hiring records was being developed and revised accordingly and had not been finalized. In addition documentation retention requirements were being refined and had not been finalized. As of early April 2014, we confirmed that the files started to be collected and reviewed for compliance with the new documentation retention requirements. ▪ The process for compliance reviews of vacancy files was being revised and had not been finalized and implemented as of the time of this review. As a result, we concluded action milestones were not complete. In early April 2014, the process was changed to ensure the compliance review takes place prior to the offer letter being issued. IA noted that during the fieldwork portion of this review, many processes and documents were being revised and updated on an on-going basis. The end objectives or deliverables could be further elaborated on to more clearly define completion criteria, eliminating any uncertainty around the status of the milestone or action plan completion. <u>Risk Impact Analysis</u> • Inaccurate reporting of action plan status increases reputational impact to OPG (and the risk of repeat findings). • Incomplete documentation, processes and undefined deliverables increase the risk that managements control objectives will not be attained.		
2	**Lack of documentation supporting management actions**		
	One finding in the AG report implied potential conflict of interest during the hiring process. (Specifically, the AG noted that there were approximately 700 groups of employees that had the same postal address, and there was little to no documentation available to demonstrate that the standard recruitment process was followed). Management undertook to perform an analysis of these exceptions in an attempt to disposition them. We reviewed the analysis performed by management and noted the following: • Management made a number of assumptions to help categorize and reduce the number of groups for analysis. The assumptions and the rationale for the assumptions were not well documented. Furthermore,	It is recommended that Management perform the following; • Document steps taken to analyze the 700 groups of employees, including all assumptions made and rationale behind those assumptions and the impact of the assumptions on the reduction of the population selected for further analysis	<u>Action Plan(s):</u> The steps and assumptions are currently being documented. These files will be retained in the Recruitment Department (confidentiality). • Documents compiled will be retained on file. <u>Owner:</u> Jennifer Strano

#	Finding	Recommendation	Management Action Plan
	discussions with management indicated that certain assumptions would need to be further developed to withstand scrutiny (e.g. rationale for why groups hired within two years of each other were removed from analysis; removal of groups where individuals performing analysis had personal knowledge of relationships, and removal of groups where first person hired was hired into a lower level position, amongst others). • Supporting documentation, such as hiring records, were not compiled and retained as support for groups exceptions analyzed. In those instances, confirmation from local HR representatives that hiring records existed was considered sufficient. In some instances limited existing supporting documentation was considered sufficient (e.g. existence of a typing test results) to demonstrate that the standard hiring process was followed. Risk Impact Analysis • Risk that the analysis of 700 groups of employees and conclusions reached did not adequately identify the underlying issues within recruitment, which could result in inappropriate or unnecessary actions being taken. There is an increased reputational risk to OPG if repeat findings were to arise if issues are not identified and adequately addressed.	and disposition. • Retain copies of the documentation gathered supporting conclusions of the analysis for all actions.	Target Completion Date: May 30, 2014
3	**Noncompliance with new OPG hiring policies**		
	As part of managements response to the AG findings new hiring policies were implemented: i) *Executive Staff Resourcing* - OPG now requires all executive (Band A-F) hiring and promotion to be approved by the ELT member and President and CEO, and ii) Re-hiring of Former OPG Employees - The Re-Hiring of Former OPG Employees procedure places boundaries around when former OPG employees, who meet certain criteria such as receiving a pension or severance package, can return to work at OPG. IA selected a sample to test for compliance with the above policies and noted one exception for the Executive Staff Resourcing procedure where sign off by required approvers occurred after the effective date of promotion. (Refer to Appendix B for details). No exceptions were found	It is recommended that management perform the following; • Establish a periodic monitoring routine to ensure compliance with the policy requirements on an on-going basis. • Implement a new control for check of new hires to payroll records to verify completeness of re-hired employee database; • Develop customized source system reports to enable compliance monitoring as	Action Plan(s): • Monthly monitoring will occur by leveraging the existing staff movement report (which is prepared monthly) that highlights all promotions and lateral movements in management • We will ensure all Bands A-F approval forms are completed to support the movements in the report. • To monitor compliance with the rehire policy, we will compile a list of all retired employees from SAP

#	Finding	Recommendation	Management Action Plan
	with respect to the Re-hiring of Former OPG Employees policy. <u>Risk Impact Analysis</u> Increased risk of non-compliance with OPG policy and managements control objectives not being met.	necessary. While IA recognizes that obtaining formal sign off prior to the effective date may be difficult, at a minimum email confirmation indicating prior approval should be retained on file as appropriate evidence.	on an annual basis, Annually, his list will be compared to the list of all Temporary and Augmented Staff employees for the same period (Temporary and Augmented staff information will be obtained from Tempus and SAP). Any employees identified as re-hired former employees from the above comparison will be then compared to the master list of re-hired employees. The master list is maintained by Recruitment on an on-going basis as re-hire approval forms are registered. Any rehires that do not have a re-hire approval form will be treated as exceptions and will be investigated further. <u>Owner:</u> Jennifer Strano <u>Target Completion Date:</u> **A-F Tracking System** – Completed/Ongoing **Re-hires Tracking:** Nuclear – Complete/Ongoing Non-Nuclear – Q3

Appendix B – Non Compliance with New OPG Hiring Policies

Name of Employee	Employee Type	Effective Date of Hire or Promotion (per SAP/re-hire form)	Sign off Date after Effective Date of Hire/Promotion	Name of Approver
[redacted]	Executive Promotion	[redacted]	January 15 and January 8, 2014	Glenn Jager Tom Mitchell (respectively)

OPG CONFIDENTIAL

Internal Audit

Nuclear Liability Cost Estimate Process

January 2015

Distribution:

Laurie Swami, SVP, Decommissioning & Waste

John Mauti, VP Finance, Chief Controller & Accounting Officer

cc: Tom Mitchell
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1.0 EXECUTIVE SUMMARY

Audit Rating[1]:	Generally Effective
Enterprise Level Impact:	Moderate

Internal Audit (IA) has completed the Nuclear Liability Cost Estimate Process audit. This was a risk-based audit identified in IA's 2014 - 2016 Strategic Audit Plan (SA Plan). The purpose of this audit was to independently assess the effectiveness of controls in the Nuclear Liability Cost Estimate process for the 2017-2021 ONFA Reference Plan Update. In view of the current project status, the audit scope was limited to governance and oversight, the major planning assumptions and the system plan.

During the course of the audit, IA identified the following process strengths:

- Terms of reference for each nuclear waste management and decommissioning program, including roles and responsibilities, major planning assumptions, deliverables and timelines, are formally defined, reviewed and approved by the respective working group lead early in the process.
- Collaborative project management approach that engages relevant stakeholders and focuses on continuous improvement.
- In recognition of the very long timeframe of the decommissioning program, high emphasis has been placed on appropriate documentation including explanation of decisions with their underlying risks and assumptions for the benefit of successive organizations over the next several decades.

IA noted that the controls relating to other governance and oversight activities of the ONFA Reference Plan Update process were also generally adequate. Moreover, the controls over the development of major planning assumptions were reasonably effective in ensuring their completeness, appropriate supporting basis and proper review and approval.

IA also identified the following findings, which have been summarized below:

- There were process issues regarding the spreadsheet model used in the preparation of the Decommissioning and Nuclear Waste Management System Plan. This process relies heavily on a single staff member who does not have a back-up and has only working knowledge of the spreadsheet model for data input but has limited knowledge of its functionality or capability. Spreadsheet logic is not documented and there is no detailed review of the spreadsheet outputs. The high level review of the System Plan report, including major planning assumptions and significant variances in nuclear waste forecasts provide some risk mitigation. Further, management had recently recognized this vulnerability and is in the planning stages of developing further mitigation measures.

- The results of the management initiated benchmarking study relating to the decommissioning cost estimate have not yet been formally assessed and incorporated in planning for the 2017 ONFA Reference Plan update. So far, there is no formal assessment of the impact of the findings and recommendations of the benchmarking study. Though their initial review indicated that the findings may not be critical to warrant immediate action, management has planned a detailed review of the report's recommendations with the cost estimate contractor.

[1] *Please see Appendix A for ratings definition*

Nuclear decommissioning and waste management are critical undertakings for OPG's operations. The preparation of cost and liability estimates for the 2017 ONFA Reference Plan update is still at an early stage. The significance of the cost, complexity and duration of this process entail significant risks that need to be diligently monitored and managed.

All findings, including the above, have been reviewed with management. They indicated that initiatives are already under way to address some of the issues and have committed to specific action plans to address the other issues. Please see Section 4.0 for specific details of all the findings along with the associated risk impact, audit recommendations and management action plans.

IA would like to take this opportunity to thank Decommissioning & Nuclear Waste Management and Business Planning and Reporting - Nuclear Waste Management for their assistance and co-operation during this audit.

Approved By:

Michael Braude
Acting VP Assurance & Chief Audit Executive

2.0 BACKGROUND

The Ontario Nuclear Funds Agreement (ONFA) sets out the risk-sharing agreement between the Province of Ontario and OPG with regard to the long-term liabilities and funding associated with nuclear waste management and decommissioning. To this effect, OPG revises the underlying baseline Nuclear Liability Cost Estimates through the submission of the ONFA Reference Plan to the Province every five years. During this period, there is an ONFA requirement to update the Reference Plan if there is an event that would trigger a material change to the cost estimates. As of December 31, 2013, the present value of liability estimates, excluding non-nuclear fixed asset removal, is around $15 Billion.

The current Reference Plan update will be effective for the years 2017 to 2021. The calculation of the cost estimates involves the use of major planning assumptions as well as lower level operational assumptions. Changes to these assumptions could result in significant changes in the amount of the total nuclear liability, which in turn, would impact OPG's required cash flow contributions to fund the liability.

3.0 AUDIT OBJECTIVES AND SCOPE

The objective of this audit was to independently assess the effectiveness of controls in the Nuclear Liability Cost Estimate process for the 2017-2021 ONFA Reference Plan Update.

A summary of the process activities that IA included in the audit scope is outlined below:

Ref	Process Activities	Audit Criteria / Key Risk Areas
A	**Governance & Oversight**	• Organizational structure and resource allocation • Roles and accountabilities • Monitoring and oversight • Project timelines and long-lead-time milestones • Risk Management including impact of significant events
B	**Review and Update of Major Planning Assumptions**	• Completeness of major planning assumptions • Basis supporting major planning assumptions • Key stakeholder engagement and approval
C	**System Plan**	• Alignment with major planning assumptions • Computation of system plan deliverables

The audit scope was determined through an inherent risk assessment facilitated by IA with key stakeholders, namely Corporate Finance and Decommissioning & Nuclear Waste Management. Fraud risk considerations have also been taken into account.

The scope of this audit specifically excluded an assessment of:

- Preparation of cost estimates and of liability
- Technical analysis or evaluation of major planning assumptions and cost estimates;
- Comprehensive / detailed evaluation of the spreadsheet models;
- Accounting adjustments and related presentation and disclosure requirements; and
- Schedule of Finance Guarantee requirements for the Canadian Nuclear Safety Commission (CNSC).

4.0 AUDIT FINDINGS

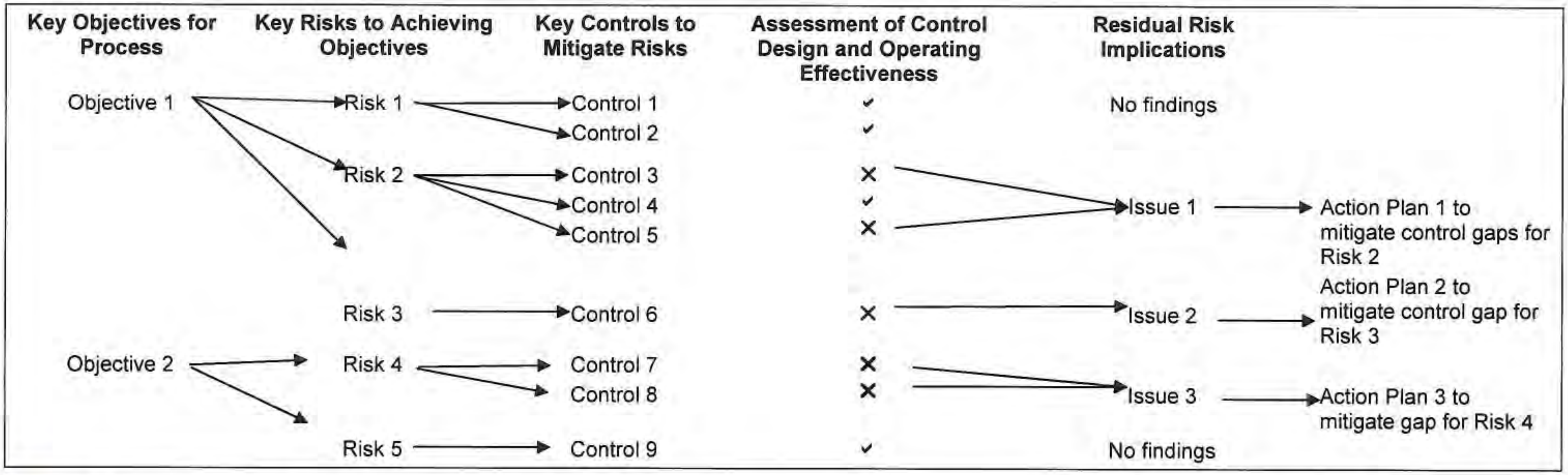
#	Finding	Process Risk Rating	Recommendation	Management Action Plan
4.1	**PROCESS ISSUES REGARDING SPREADSHEET USED IN SYSTEM PLAN PREPARATION**			
	The process for preparing the Decommissioning and Nuclear Waste Management System Plan relies heavily on a single staff member. Through discussion with management and review of documentation, IA noted that the Section Manager, Nuclear Waste System Planning, has sole responsibility for gathering inputs, running the spreadsheet model and validating the output with key stakeholders. There is no back-up for this role and no other staff is trained on the system plan update process. Also, the single power user only has working knowledge of data input to run the spreadsheet model whereas knowledge of its functionality or capability is limited. Moreover, the System Plan spreadsheet model has: • no documentation of spreadsheet logic and regular periodic independent inspection thereof • no detailed review of the spreadsheet outputs The System Plan plays a critical role in the ONFA Reference Plan update by providing the forecast volumes for all nuclear waste streams. The spreadsheet model used for this computation is fairly complex with formulas and links among over fifty tabs. Currently, key stakeholders such as the ONFA Project Manager and the Lifecycle Liability Management group of the NWMO perform high level reviews of the System Plan report. Their reviews of the major planning assumptions and of significant variances in nuclear waste forecasts provide some mitigation to the risk of major errors and / or omissions. The forecasts are not expected to fluctuate significantly year over year unless there are significant	Moderate	Management should: a) assign a back-up staff for the System Plan update, who should be provided adequate training b) consider upgrading / replacing the System Plan spreadsheet model and ensure that appropriate documentation relating to its logic /operation is maintained c) implement detailed review of the System Plan model inputs and outputs, and embed it in the process	Action Plan(s): 1) Establish a competent back-up in the interim. 2) As per current plan, evaluate options and establish a project plan for an improved System Plan management system which provides for quality checks and controls to mitigate risk of errors. 3) Pending the outcome of the evaluation in (2) above, establish appropriate review of inputs and outputs. Owner: Vishan Seegobin, Manager Decommissioning & Safe Storage Engineering Target Completion Date: 1) March 31, 2015 2) June 30, 2015 3) June 30, 2015

#	Finding	Process Risk Rating	Recommendation	Management Action Plan
	changes to the underlying major planning assumptions. As a result of recent changes in the Decommissioning & Nuclear Waste Management organization, the newly appointed VP Nuclear Decommissioning has taken over the accountability for the System Plan. Management has acknowledged the issues noted by IA and indicated that initiatives are under way to address them. Risk Impact Analysis • system plan update may be inefficient and / or not cost effective in the absence of the current incumbent • errors and /or omissions may occur in the computation of nuclear waste volume forecasts			
4.2	**RESULTS OF MANAGEMENT INITIATED DECOMMISSIONING BENCHMARKING STUDY WERE NOT FORMALLY ASSESSED**			
	The results of the benchmarking study relating to the decommissioning cost estimate have not yet been formally assessed and incorporated in planning for the 2017 ONFA Reference Plan update. So far, there is no formal assessment of the impact of the findings and recommendations of the "Benchmarking of Nuclear Power Plant Decommissioning Cost Estimates" report, Dec 2012 by Kinetrics, which was commissioned as part of management's ongoing process improvement initiatives. Management indicated that due to the inherent limitation of comparability, benchmarking results may not be conclusive. From their initial review, management concluded that the findings may not be critical to warrant immediate action. It is nevertheless important to formally assess the findings and recommendations with appropriate documentation of dispositioning and conclusions, particularly when the report concludes that the recommendations were significant and should be treated as high priority.	Moderate	Management should perform a formal assessment of the findings and recommendations of the Benchmarking of Nuclear Power Plant Decommissioning Cost Estimates report in a timely manner. Appropriate documentation regarding the dispositioning of the findings and recommendations should be retained.	Action Plan(s): Continue with plan to have decommissioning cost estimator evaluate and provide recommendations to management to address the cost benchmarking study in a timely manner. Management will then review cost estimator's evaluation and formalize an OPG report which addresses study findings and recommendations. Owner: Vishan Seegobin, Manager Decommissioning & Safe Storage Engineering

#	Finding	Process Risk Rating	Recommendation	Management Action Plan
	The requirement in the Statement of Works for the cost estimate contractor to review the report and come up with suggested actions supports the intent to assess mitigation actions. Risk Impact Analysis • Quality of decommissioning cost estimates may be impacted • Timely implementation of improvement initiatives may be impacted			<u>Target Completion Date:</u> June 30, 2015

APPENDIX A: OVERVIEW OF AUDIT RATING METHODOLOGY

IA's ratings for operational audits of OPG business processes are derived from an assessment of the management controls that are in place to mitigate key risks to the achievement of process objectives. The diagram below illustrates IA's basic approach to conducting an audit. If control deficiencies are identified that prevent IA from providing reasonable assurance that the process objective will be met (i.e. key risks are adequately mitigated), an audit issue will be noted and a corrective action plan from management will be required.



- *Effective*: control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- Generally Effective: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- Requires Improvement: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- Not Effective: control and risk management practices are not designed and/or are not operating effectively.

The second tier to IA's audit rating is an indication of the implications of the residual risk at the broader, enterprise level. This rating of "High", "Moderate" or "Low" is intended to answer the "so what?" question for senior management and the Audit and Risk Committee by giving context to audit results in terms of their impact on OPG as a whole.

OPG CONFIDENTIAL

Internal Audit

Corporate Strategy & Planning Process Audit

April 20, 2015

Report Rating: **Generally Effective**

Distribution:

Andrew Teichman
Vice President Corporate Strategy & Planning

cc:	Tom Mitchell	President & CEO
	Carlo Crozzoli	SVP Corporate Business Development & CRO
	Beth Summers	SVP & Chief Financial Officer
	Jody Hamade	VP Enterprise Risk Management
	John Mauti	VP Business Planning & Reporting
	Bob Gerrard	Director Corporate Strategy & Planning

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1.0 EXECUTIVE SUMMARY

1.1 Report Rating and Summary of Findings

Report Rating: Generally Effective

No.	Finding	Risk Type	Risk Rating[1]		
			High	Moderate	Low
1	OPG's Strategic Direction was not consistently communicated broadly across the organization beyond the Senior Leadership and senior management.	Strategic		X	
2	The enterprise capital allocation process was not clearly defined and documented in sufficient detail.	Financial		X	
3	The usage of strategic Key Performance Indicators ("KPI's") is still evolving and has not been fully integrated into strategic planning.	Strategic		X	
4	The process used for assessing the internal business environment was not formally structured and documented.	Strategic			X
Total		**4**	–	**3**	**1**

1.2 Background

This audit was conducted given the overall significance of the Corporate Strategy & Planning process in determining OPG's future and as part of a requirement to attain cyclical audit coverage of Business Unit ("BU") processes.

The Corporate Strategy & Planning ("CSP") process is critical in supporting the development of OPG's strategic direction and priorities which include the following key strategic imperatives:

- Continued *operational excellence* in safety, environmental management and cost efficient and reliable operations;
- *Project excellence* in executing OPG's generation portfolio renewal/growth program; and
- Improved *financial sustainability* via pursuit of revenue enhancement opportunities and other strategic initiatives.

One of OPG's key strategic priorities is to improve its financial performance by growing net income and return on equity. Key challenges to the strategic imperatives include increased scrutiny by the Shareholder, other stakeholders and the public regarding cost transparency, efficiency and profitability and the related risk to obtaining required regulatory rate increases. In 2012, as part of OPG's Business Transformation initiative, the CSP group comprising three full time employees reporting to the SVP of Corporate Business Development & CRO, was established and was given the responsibility of facilitating the corporate strategy & planning process.

[1] Please refer to Appendix B for risk rating definitions

1.3 Audit Objective & Scope

The objective of this audit was to independently assess whether controls and processes in Corporate Strategy & Planning contribute to the achievement of the key strategic imperatives.

In order to achieve the audit objective, the scope of the audit included testing on a sample basis whether:

A. Process / Approach

- The primary Policy (the OPG Business Model) and supporting procedures for the CSP process have been established, documented, communicated, periodically updated, and consistently followed; and
- Roles, accountabilities and expectations for CSP and BUs were defined and communicated.

B. Assessment of Internal and External Environment

- An analysis of the external environment was performed that included factors such as market trends, competitors, customers, risks and opportunities;
- An analysis of the internal environment was performed that considered factors such as resources, capabilities, strengths, weaknesses, risks and opportunities; and
- Briefings on strategic matters were developed, documented and provided timely to senior management and the Board.

C. Development of Strategic Direction and Planning Context

- Scenarios, options, responses, outcomes, and related changes were identified and assessed, and allowed for course correction where necessary;
- CSP provided oversight on the alignment of BU objectives and plans to the strategic direction and for consistency among the BUs;
- Enterprise level capital allocation guidance was established and communicated;
- Finance supported the BUs in aligning their capital allocation planning with strategic plan guidelines; and
- Strategic direction and factors for consideration in business planning were established and communicated, and were aligned with the long term financial outlook.

D. Execution of Corporate Strategy by the Organization

- CSP identified, evaluated and managed acquisition and divesture opportunities in accordance with strategy;
- CSP support was provided on strategic planning initiatives and to BUs on their functional strategy development; and
- Progress on the achievement of strategic milestones was periodically monitored and reported and KPI's were tracked.

The scope covered the planning cycle for the 2015 – 2017 Business Plan that occurred in Financial Year 2014.

1.4 Conclusion

Positive Observations

- Corporate strategy and planning has evolved into a well coordinated process, with strong engagement of Senior Leadership; and
- The CSP process has integrated well with the business planning cycle and the long term financial outlook.

Key Internal Control Findings and Recommendations

- OPG's Strategic Direction was not consistently communicated broadly across the organization beyond the Senior Leadership and senior management;
- The enterprise capital allocation process was not clearly defined and documented in sufficient detail; and,
- The usage of strategic KPI's is still evolving and has not been fully integrated into strategic planning.

As a result of these findings, IA recommends that CSP:

- Facilitate the approach for communicating the strategic direction to a broader audience;
- Document the enterprise capital allocation process to more clearly define the major activities and related roles and responsibilities; and
- Refine and integrate the set of strategic KPI's currently under development into the strategic planning process.

The findings noted in the report have been reviewed with management who has committed to specific action plans to address them. Please refer to Section 2.0 for specific details of the above findings along with the associated potential causes and impacts, audit recommendations and management action plans.

2.0 DETAILED AUDIT FINDINGS

Internal Audit identified the following detailed findings and recommendations which have been risk rated based on the definitions outlined in Appendix B.

1. OPG's Strategic Direction was not consistently communicated broadly across the organization beyond the Senior Leadership and senior management.	**Moderate**

An organization's strategic direction and priorities outline areas of focus for the organization over the long term along with related goals and high-level plans for achieving them. Communication of this direction to employees across the organization facilitates the alignment of employee and team goals to the overall goals of the company.

The CSP group held presentations with the Executive Leadership Team ("ELT") and their management teams in mid-2014 to communicate the strategic direction. CSP's expectation was for the strategic direction to be cascaded down to BU staff via the management teams.

In our interviews with the ELT, it was noted that strategic direction was not fully cascaded to the lowest levels within the organization and that the messaging could have been broader.

Potential Causes & Impact

<u>Potential Causes:</u>

- Although a one-page slide was prepared summarizing OPG's strategic direction, it was not disseminated broadly using multiple channels to all employees. CSP relied on the BUs to cascade the communication of the strategic direction and had not intended to use any other direct means of communication.
- CSP received senior management direction to limit distribution of strategic direction details (e.g. the Strategic Plan) to ELT members only.

<u>Impact</u>:

- Employees may not be fully aware of OPG's corporate strategic direction and may work towards different goals, or may not be fully engaged in the achievement of the organization's goals.

Recommendation	Management Action Plan	Owner & Target Completion Date
CSP should work with internal stakeholders to enhance communicating corporate strategic direction to a broader internal audience through channels such as the intranet, broadcast emails, posters, town halls, etc. Following this, CSP should facilitate its implementation.	1. Establish a communications plan for more broadly communicating OPG's strategic direction following the next update to OPG's strategic plan. 2. Implement communications plan.	Andrew Teichman *Vice President, Corporate Strategy & Planning* 1. Jan. 31, 2016 2. May 31, 2016

2. The enterprise capital allocation process was not clearly defined and documented in sufficient detail.	**Moderate**

Enterprise capital allocation is a centre-led activity for providing strategic allocation of capital among the various BUs over the long-term. The process combines a “top down” and “bottom up” capital allocation process that culminates in the establishment of a set of capital guidelines (i.e. Project OM&A, Capital and Provision Funding) for business planning that are consistent with OPG’s strategic direction. In order to ensure the effective operation of the enterprise capital allocation process, clearly defined activities, roles and accountabilities are necessary.

In our review, we noted that the enterprise capital allocation process was not clearly defined and documented in sufficient detail. We further noted that:

- There is limited process information available to stakeholders involved;
- Only the Director, CSP has detailed knowledge of the activities within the process, with limited back-up;
- Documentary evidence to demonstrate the performance of some activities was not retained, for example:
  - In our review of 20 BP capital allocation variances from the guidelines, four variances had no documentation to demonstrate the review of the variances. However, the Director, CSP was able to provide reasonable explanations for those four variances (See Appendix A for details); and
  - The review by the VP, CSP was not formalised as part of the process;
- The distinction between Finance’s role and that of the Director, CSP in supporting the BUs with the alignment of their capital allocation planning with strategic plan guidelines was not clearly defined.

Potential Cause & Impact

Potential Cause:

- Since the development of the enterprise capital allocation process in 2012 and its launch in 2013, CSP has focused on working with stakeholders to help make the process practical, efficient and flexible and thus have spent limited time on formalizing and documenting the enterprise capital allocation process.

Impact:

- Key steps in the process may not be performed completely or correctly, and the process may not be performed efficiently or in a sustainable manner.

Recommendation	Management Action Plan	Owner & Target Completion Date
CSP should document the enterprise capital allocation process to include key activities and roles and responsibilities of the CSP, Finance and operations roles for capital allocation. Explore strategies to share knowledge and support coverage of the process within CSP.	1. Document the enterprise capital allocation process, incorporating inputs from key stakeholders. 2. Expand responsibility and knowledge of the process and background within the group.	Andrew Teichman *Vice President, Corporate Strategy & Planning* Jan. 31, 2016

3. The usage of strategic Key Performance Indicators (“KPI’s”) is evolving and has not been fully integrated into strategic planning.	**Moderate**

Use of KPI’s is a common business practice for setting quantitative metric targets and for measuring progress against related goals. Periodic assessment of performance using KPI’s helps identify any areas for improvement.

In 2013, the CSP group commenced development of strategic KPI’s with input from key stakeholders, and in 2014 presented a proposed set to the Board. However, to date, these KPI’s have not been formally integrated in strategic planning. IA found that:

- KPI’s are primarily focused at the BU-level and not at the entity-wide level;
- Strategic KPI’s have not been formally integrated into strategic planning; and
- Interviews with a sample of eight ELT members highlighted a need for strategic KPI’s.

As such, a formal evaluation of OPG’s high level performance against the strategic plan and the three strategic imperatives has not been initiated.

Potential Cause & Impact

Potential Cause:

- CSP decided to gradually implement the use of Strategic KPI’s in strategic planning commencing in 2015/16 due to sensitive information.

Impact:

- Gaps between actual and targeted strategic performance may not be identified to allow for effective course correction in a timely manner.

Recommendation	**Management Action Plan**	**Owner & Target Completion Date**
CSP should work with key stakeholders to complete the set of strategic KPI’s and integrate these into the strategic planning process.	Refine strategic KPI’s and incorporate into next revision of OPG’s strategic plan.	Andrew Teichman *Vice President, Corporate Strategy & Planning* Jan. 31, 2016

4. The process used for assessing the internal business environment was not formally structured and documented.	**Low**

Analysis and evaluation of the internal business environment should be documented including appropriate information sources, and expected inputs from BUs.

CSP's process for obtaining information on the internal business environment is not formally structured and is based primarily on the BUs planning process. Other inputs are obtained through informal discussions with select individuals or through review of existing documentation. IA found that:

- It was unclear how the selected individuals and information sources used for the assessment of the internal environment ensured sufficiency for the internal assessment;
- CSP expectations from the BUs were not clearly established and communicated; and
- Information requests from CSP to the BUs or information updates from the BUs to CSP were ad hoc.

Potential Cause & Impact

Potential Cause:

- As the process was being developed, CSP chose to leverage existing business planning and reporting mechanisms and network of existing relationships across the organization to obtain this information for the internal assessment. Other priorities limited the time available to formalize the process.

Impact:

- Internal business environment information obtained and used for strategic planning purposes may be incomplete, and the process may not be performed efficiently or in a systematic manner.

Recommendation	Management Action Plan	Owner & Target Completion Date
There should be a standard list of interviewees and information sources.	CSP will document its internal assessment process, including key sources of information and analysis for supporting strategic planning efforts.	Andrew Teichman *Vice President, Corporate Strategy & Planning* Jan. 31, 2016

APPENDIX A - DETAILS OF TESTING EXCEPTIONS

No documentation was retained to support the variance review for the following capital projects sampled:

1. Lower Mattagami
2. Regulated Hydroelectric
3. Adam Creek Spillway Expansion
4. Non – Hydroelectric Renewables

APPENDIX B - RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgment by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

Internal Audit

Pension and OPEB Process Audit

September 28, 2015

Report Rating: **Effective**

Distribution:

Barb Keenan
SVP People & Culture

Beth Summers
SVP & Chief Financial Officer (Chair of Pension Committee)

Craig Halket
VP Total Rewards

cc:	Jeffrey Lyash	President & CEO
	Carlo Crozzoli	SVP Corporate Business Development & CRO
	Chris Ginther	SVP General Counsel & Chief Ethics Officer
	David Kaposi	VP Chief Investment Officer
	Jody Hamade	VP Enterprise Risk Management
	Jenny Ruiz	Director Controllership

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1.0 EXECUTIVE SUMMARY

1.1 Report Rating and Summary of Findings

Report Rating: **Effective**

No findings were noted.

1.2 Background

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan and other post-employment benefits ("OPEB"), which include group life insurance, self-funded health care benefits and long-term disability benefits. Administration of these programs is outsourced to Morneau Sheppell for the pension plans and to Sun Life Financial for OPEB. OPG's Pension and OPEB liabilities are significant, as at December 31, 2014 were $3.6 billion and $3.1 billion, respectively. These obligations are impacted by factors such as interest rates, plan amendments and cost escalation.

1.3 Objective & Scope

The objective of this audit was to assess the design and operating effectiveness of controls over the oversight, management and administration of OPG's pension and OPEB plans to meet contribution and payment requirements.

The scope of the audit included testing, on a sample basis, to determine whether:

A. Pension and OPEB Strategies, Objectives and Risks

- Strategies and plans have been established and actions taken to address anticipated Pension and OPEB liabilities;
- Significant risks impacting the OPG pension plan and OPEB were clearly identified, assessed and action plans were developed to mitigate these risks; and
- Significant risks and mitigation plans were communicated and approved by the Board of Directors.

B. Governance and Communication

Policies & Procedures

- Pension and OPEB management policies and procedures were documented, approved, communicated and periodically reviewed;
- Governance objectives for the oversight, management and administration of the OPG Pension Plan and OPEB were clearly defined and documented;
- Roles, responsibilities and accountabilities of all participants in the pension plan governance process were clearly documented and reflected in current processes; and
- Pension plan funding guidelines considered applicable Canadian Association of Pension Supervisory Authorities ("CAPSA") guidelines, based on criteria such as funding objectives, management of key risks faced by the plans, funding volatility factors, funding target ranges and cost sharing mechanisms.

Compliance Monitoring

- Processes were in place to ensure that Pension Plans and OPEB were effectively governed and administered in accordance with the applicable policies and procedures; and
- Pension plan interpretations, complaints and appeals were dealt with in an appropriate and timely manner.

Communication & Reporting

- Pension and OPEB communications were accurate, timely, relevant and in accordance with regulatory requirements and other applicable policies; and
- The funded status of the pension plan reflected actuarial results and was reported to senior management and the Board of Directors.

C. Pension and OPEB Processing and Administration

Contributions, Payments and Data Integrity

- Employee contributions to pension plans were consistent with contribution requirements determined by the Plan Administrator and relevant collective agreements;
- Pension and OPEB entitlements and commuted values were calculated accurately and validated prior to communication with plan members;
- Pension payments were accurate, based on criteria such as years of service and salary history and only made to valid plan members;
- Benefits were only reimbursed to valid OPEB recipients for claims that included spouse and dependants and that were supported by proper documentation;
- Pension payroll deductions were accurate, complete and remitted to the Plan Administrator;
- Pension and OPEB plan membership setup was based on proper documentation; and
- Pension and OPEB terminations were accurately processed and transferred to other registered plans or paid in cash less tax withholdings.

Plan Administration Service Providers and Expenses

- Expenses charged to pension plans were eligible, appropriately approved and recorded in a timely manner;
- Pension plans and OPEB administration service providers were hired in accordance with OPG's procurement procedure; and
- Service providers' performance was periodically benchmarked and evaluated against standards defined in the pension plan and OPEB Service Level Agreements.

The scope of the review covered pension and OPEB processes and controls for the period January 1, 2014 to March 31, 2015.

The scope of this audit specifically excluded an assessment of pension fund investment activities, which was covered in a prior internal audit. When assessing design, we have considered internal controls evaluated as part of OPG's ICOFR program. Where ICOFR controls have been utilized, we have not tested the effectiveness of these controls in order to avoid duplication of effort.

1.4 Conclusion

No reportable findings were identified in this audit. IA noted the following positive observations during the execution of this audit:

- There is regular Pension Committee and Board committees' monitoring of the enterprise-level risk relating to "increase in future pension plan funding requirements and OPEB programs" and the status of risk treatment plans. Good progress has been made against these plans; and
- Pension and OPEB administration and processing are well-established processes which are consistently performed by the Total Rewards team along with the support of industry recognized service providers and advisors.

APPENDIX A - RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgment by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

OPG CONFIDENTIAL

Internal Audit

Nuclear Liability Cost Estimate Audit

December 24, 2015

Report Rating: **Generally Effective**

Distribution:

Glenn Jager
President, OPG Nuclear and Chief Nuclear Officer

Laurie Swami
SVP Decommissioning & Waste

Carlo Crozzoli
Interim SVP Finance, Strategy & Risk and Chief Financial Officer

John Mauti
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	Janice Ding	Director Internal Audit
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1.0 EXECUTIVE SUMMARY

1.1 Report Rating and Summary of Findings

Report Rating: Generally Effective

No.	Finding	Risk Type	Risk Rating[1]		
			High	Moderate	Low
1	An in-depth analysis of variances for the Decommissioning program was not presented for the Steering Committee's review.	Operational		X	
2	The rigor of the Decommissioning working group's review of contingency allowances was not clearly evident.	Operational		X	
3	Formulas in critical spreadsheet cost models were not protected from unauthorized or inadvertent changes.	Operational			X
Total		**3**	**–**	**2**	**1**

1.2 Background

The Ontario Nuclear Funds Agreement ("ONFA") sets out the risk-sharing relationship between the Province of Ontario and OPG to fund the long-term liabilities associated with nuclear waste management and the decommissioning of OPG owned nuclear facilities. The funding requirements, outlined in the ONFA Reference Plan, are based on cost estimates and related assumptions such as the planned life of the stations, economic conditions and timing of waste programs. As of June 30, 2015, the present value of the liability for decommissioning and nuclear waste management as per OPG's financial statements was $17 billion.

The ONFA Reference Plan has a mandated five-year review cycle and the current update will be effective for the years 2017 to 2021. Specialist third party organizations such as the Nuclear Waste Management Organization ("NWMO") and TLG Services Inc. support the Reference Plan update. The cost estimates are reviewed by the ONFA Steering Committee which consists of executives from OPG and a representative from the Ontario Finance Authority ("OFA"). The final ONFA Reference Plan update submission to the OFA is scheduled for September 2016.

This audit was conducted given the importance of the nuclear liability cost estimates on OPG's cash flows from contributions to the Decommissioning Fund and the Used Fuel Fund. The last audit was completed in 2014 and focused on the ONFA program governance, major planning assumptions and the system plan.

[1] Please refer to Appendix A for risk rating definitions

1.3 Objective & Scope

The objective of this audit was to assess the design and operating effectiveness of controls to provide reasonable cost estimates for the 2017 - 2021 ONFA Reference Plan update submission.

The scope of the audit included a review of processes and testing, on a sample basis, to determine whether:

A. Inputs to Cost Estimates

- Program cost estimates were based on valid and approved inputs including:
  - major planning assumptions;
  - decommissioning and nuclear waste management system plan;
  - operating cost estimates including labour, materials and external purchase agreements from the 2016 to 2018 business plans; and
  - other inputs such as regulatory requirements and Operational Experience ("OPEX").

B. Preparation of Cost Estimates

- Cost estimates prepared by third party cost estimators were consistent with their approved scope of work which included a comprehensive review of the cost estimates, variance analyses and advice on nuclear waste management practices;
- Spreadsheet cost models were protected by logical access, backup, version control, logic inspection and review control;
- Program cost estimates reflected key program interdependencies including:
  - impact of the expansion of L&ILW Deep Geological Repository ("DGR") on decommissioning waste and on temporary storage of operational waste;
  - allocation of common function costs such as security services costs; and
  - impact of the timing of used fuel retrieval and in-service date of Used Fuel DGR on used fuel storage.
- Contingency allowances in cost estimates were based on risk assessments, uncertainties and established industry practices; and
- Cost estimate calculations were accurate.

C. Review and Approval of Cost Estimates

- Program cost estimates were reviewed and approved by the respective program owners, other key stakeholders and the ONFA Steering Committee through a challenge process.

The scope included the activities that supported the preparation of the cost estimates for the 2017 to 2021 ONFA Reference Plan update submission. Internal Audit ("IA") also performed a follow-up on management actions from the 2014 audit, to ensure the actions were effectively implemented.

1.4 Conclusion

Positive Observations

- External decommissioning and nuclear waste management specialists have been engaged to support the development of cost estimates; and
- There is a comprehensive cost estimate review and challenge process by key stakeholders from Nuclear Operations, Controllership, Commercial Operations, other programs and OFA staff.

Findings and Recommendations

- An in-depth analysis of variances was not presented for the Steering Committee's review of the Decommissioning program. A detailed analysis of the impact of key cost drivers on the 2017 ONFA cost estimates including any further updates should be presented to the Steering Committee in a manner consistent with the other programs; and
- The Decommissioning working group could not clearly demonstrate the rigor of their review process for contingency allowances. A structured approach to reviewing and determining contingency allowances, including adequate documentation that is consistent with the other programs should be implemented.

The findings noted in the report have been reviewed with management and they have committed to specific action plans to address them. Please refer to Section 2.0 for specific details of the above findings along with the associated risk impacts, audit recommendations and management action plans.

2.0 DETAILED AUDIT FINDINGS

Internal Audit identified the following detailed findings and recommendations which have been risk rated based on the definitions outlined in Appendix A.

1. An in-depth analysis of variances for the Decommissioning program was not presented for the Steering Committee's review.	**Moderate**

Program working groups are responsible for overseeing the activities of the cost estimate contractors, including a review of the draft cost estimates prior to challenge review meetings with key stakeholders and the Steering Committee. To validate the reasonableness of the cost estimates, a variance analysis is performed to explain or justify the significant variances between the 2017 and the 2012 ONFA cost estimates.

IA noted that an in-depth analysis of variances for the Decommissioning program was not presented to the Steering Committee, which was inconsistent with the other four programs. Significant variances between the 2017 and the 2012 ONFA cost estimates were only identified by high level cost drivers such as:

- L&ILW decommissioning waste disposition: $926M
- Staffing during transition to safestore: $872M
- ILW containers: $411M

The relevant main planning assumptions for 2017 ONFA and the corresponding 2012 assumptions were listed in the Steering Committee presentation. There was no analysis provided on the impact of significant changes in planning assumptions on the high level cost drivers. The variances were also not explained in terms of volume, price or schedule delay changes.

Additional follow-up work noted that the Decommissioning working group had subsequently presented more detailed analysis of L&ILW decommissioning waste disposition at the request of the Steering Committee. IA was also able to verify that the $411M variance for ILW containers was justified by volume and price changes.

Potential Cause & Impact

Potential Cause:
Lack of clarity on the requirement for the depth of variance analysis may have contributed to this finding.

Impact:
Errors or omissions in the input of assumptions and in the computation of the cost estimates may not be detected.

Recommendation	**Management Action Plan**	**Owner & Target Completion Date**
The Decommissioning working group should maintain and update a detailed analysis of the impact of key cost drivers on the 2017 ONFA cost estimates until the final ONFA submission in 2016. The updated variance analysis should be reviewed by the Steering Committee.	The Summary Decommissioning Cost Estimate report will be presented to the Steering Committee for review, highlighting: • changes in planning assumptions; and • analysis of significant variances with an assessment of the impact of key cost drivers such as volume, price and schedule delay changes.	Jerry Keto VP Nuclear Decommissioning March 15, 2016

2. The rigor of the Decommissioning working group's review of contingency allowances was not clearly evident.	Moderate

For the 2017 ONFA Reference Plan update, each program working group is required to review the 2012 ONFA contingency allowances and their supporting basis at the Work Breakdown Structure ("WBS") activity level. The working group with the support of the cost estimate contractor performs a risk assessment of uncertainties based on factors such as the probability and impact of unforeseeable events, operating experience and industry best practices. The allowances are then updated based on the results of the risk assessment.

IA noted that the Decommissioning working group could not clearly demonstrate evidence of review of the contingency allowances for their program. The review of the allowances for each WBS activity, including the related risk assessment and the basis of the 2017 ONFA allowances, was not consistently documented in the working group meeting minutes or other documentation.

Upon the working group's request, the cost estimate contractor provided reasonable explanation for the basis of allowances and the changes from 2012 ONFA for a test sample.

Potential Cause & Impact

Potential Cause:

- A structured approach to contingency-related risk assessment, determination of allowances and required documentation was not formalized; and
- Tendency to rely on the cost estimate contractor that has been involved since the first ONFA Reference Plan update.

Impact:

The Decommissioning cost estimates may include inadequate or excess contingency allowances.

Recommendation	Management Action Plan	Owner & Target Completion Date
The Decommissioning working group should implement a structured approach to reviewing and determining contingency allowances, including adequate documentation that is consistent with the other programs.	The process of reviewing the allowances applied to decommissioning activities will be enhanced by: 1) developing a structured process of reviewing allowances, including documentation requirements; and 2) documenting discussions relating to contingency-related risk assessment and decisions on the allowance percentage to be applied to each WBS activity.	Jerry Keto VP Nuclear Decommissioning May 30, 2016

3. Formulas in critical spreadsheet cost models were not protected from unauthorized or inadvertent changes.	**Low**

For L&ILW Operations, L&ILW Long Term Management and Used Fuel Operations programs, NWMO uses spreadsheet models that compute very high value cost estimates and contain some fairly complex formulas with links, conditions and calculations. The cost models should be subject to spreadsheet controls to ensure the integrity of the data and the accuracy of the calculation.

IA noted that while the spreadsheets are password-protected to restrict access to authorized users, the cells containing formulas are not password-protected to prevent unauthorized or inadvertent changes.

Currently, NWMO relies on its Spreadsheet Quality Assurance ("QA") process by a person independent of the preparer to verify the logic of changes in formulas and a sample of other formulas. In addition, variance analysis is performed to identify significant errors in the formulas.

Potential Cause & Impact

<u>Potential Cause:</u>
Password-protection of cells containing formulas was not an established requirement for critical spreadsheets.

<u>Impact:</u>
Inaccurate calculation of cost estimates due to inadvertent changes.

Recommendation	**Management Action Plan**	**Owner & Target Completion Date**
The ONFA Steering Committee should require NWMO to implement password-protection of cells containing formulas in all spreadsheet models.	OPG management will review NWMO's access and quality control procedures to determine the need for password-protection on cells. OPG's internal control standards do not require cell protection as long as other controls are in place. With access to the cost model restricted to 4-5 staff at the network and at the file level, NWMO's ISO certified QA program, and OPG's internal review by qualified resources, controls may be sufficient as is. Due to changes in assumptions and other inputs, formulas are often updated, requiring skilled staff to have the ability to make the changes, which will then be subject to multiple reviews. Cell protection may therefore not be required.	John Mauti VP Chief Controller & Accounting Officer April 15, 2016

APPENDIX A – RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgment by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

OPG CONFIDENTIAL

Internal Audit

Compensation Audit – 2013 Auditor General HR Findings Follow-up

January 8, 2016

Report Rating: **Effective**

Distribution:

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Craig Halket
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Glenn Temple
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1.0 EXECUTIVE SUMMARY

1.1 Summary of Internal Audit Findings

Report Rating: **Effective**

Ref #	Finding	Risk Type	Risk Rating[1]		
			High	Moderate	Low
1	Selected relocation expenses were paid to employees without the review and processing by the Real Estate department and some related mileage expenses exceeded allowable amounts.	Operational			X
2	Purchase guarantees on employees' relocation properties and carrying costs were not tracked.	Operational			X
Total		**2**	**-**	**-**	**2**

1.2 Background

In 2013, the Auditor General ("AG") of Ontario issued an audit report of OPG's Human Resources.

The AG's report highlighted findings in the following areas related to compensation:

- Annual base salaries exceeded maximum amounts set out in base salary schedule;
- Salary levels and certain benefits such as housing and moving allowances and pensions were comparatively higher than other public sector organizations; and
- A stronger link was needed between financial incentives and staff performance.

As a result, the AG recommended that OPG review and monitor compliance regarding compensation processes and improve the comparability of salary and benefits to other public sector organizations.

In response to the AG findings, OPG has taken a number of actions including:

- Reviewing the compensation structure internally and implementing segmented compensation based on external recommendations;
- Completing regular salary reviews to ensure compliance with policies; and
- Completing benchmark studies and monitoring salary levels.

In June 2015, the Ontario Internal Audit Division ("OIAD") completed a review on behalf of the Ministry of Energy ("Ministry") of OPG's actions taken and planned regarding the AG's recommendations. OIAD's report included a recommendation that OPG Internal Audit ("IA") provide the Ministry with independent and objective assurance that compensation practices were operating satisfactorily.

[1] Please refer to Appendix B for risk rating definitions

1.3 Audit Objective & Scope

The objective of the audit was to assess the design and operating effectiveness of improvements to compensation processes and controls to promote compliance with policy and consistency with other public sector organizations.

The scope of the audit included a review of the improvements to HR processes and testing, on a sample basis, to determine whether:

A. Salary Compensation

- An independent study was completed to benchmark salary levels and management has taken actions to address recommendations in the study;
- Salary adjustments were approved, with documented justification and accurately processed in accordance to policy;
- Annual base salaries were paid out within maximum amounts set out in the base salary schedule for employees who have received salary increases;
- Compliance reviews of salary processes were conducted and reported; and
- An annual review was performed for compliance with Government compensation legislation (Bill 55) to support CEO attestation.

B. Pension

- An independent study was completed to benchmark pension costs and management has taken actions to address recommendations in the study; and
- Improvements were made in reducing pension costs.

C. Housing, Moving and Other Allowances

- Housing, moving and other allowances were processed and paid out in accordance with policy;
- Allowance amounts were reasonable; and
- Housing, moving and other allowances were justified for bona fide business purposes, supported by documentation and approved by management.

D. Annual Incentive Compensation

- Executive incentive ratings were supported with documented performance evaluations linked to individual performance for Bands A to E
- The distribution of executive incentive ratings are more consistent with bands G - L; and
- Peer challenge sessions on individual annual performance ratings were conducted by business unit management.

E. Staffing Levels

- Staff levels for executive and senior management have decreased year over year for better alignment with the overall staffing levels.

The scope covered compensation activities from October 1, 2014 to September 30, 2015.

1.4 Conclusion

Positive Observations

Salary Compensation

- A due diligence process was established for review and approval of salary increases above the maximum 10% guideline;
- Quarterly reviews of salary adjustments are being completed by Human Resources to ensure adherence to salary guidelines; and
- Employees who received salary increases were within maximum amounts set out in the base salary schedule including those related to compression, promotions or lateral movements. Pay compression increases were limited to a guideline of 3% of the highest paid subordinate.

Pension

- Effective January 2016, as part of the pension cost reduction strategy, pension changes have been implemented to increase employee contributions and extend the age of retirement entitlement.

Housing, Moving and Other Allowances

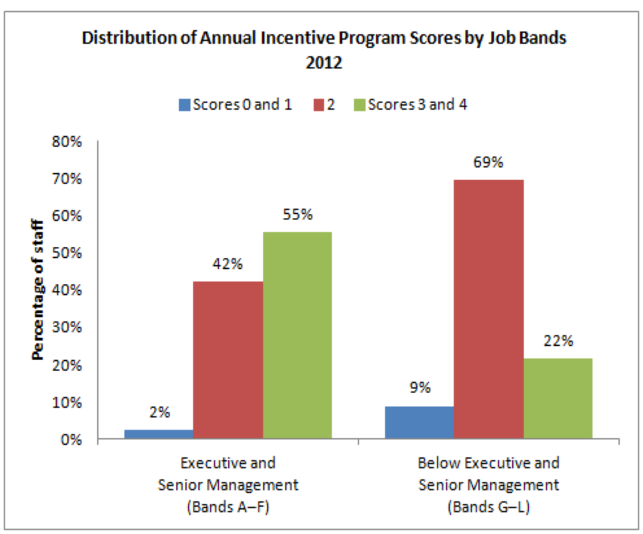
- Housing and relocation changes made throughout 2014 included the adoption of the Ontario Public Service ("OPS") relocation policy for management, the implementation of the Relocation Steering Committee and management reviews of employee relocation case files for non-standard expenses.

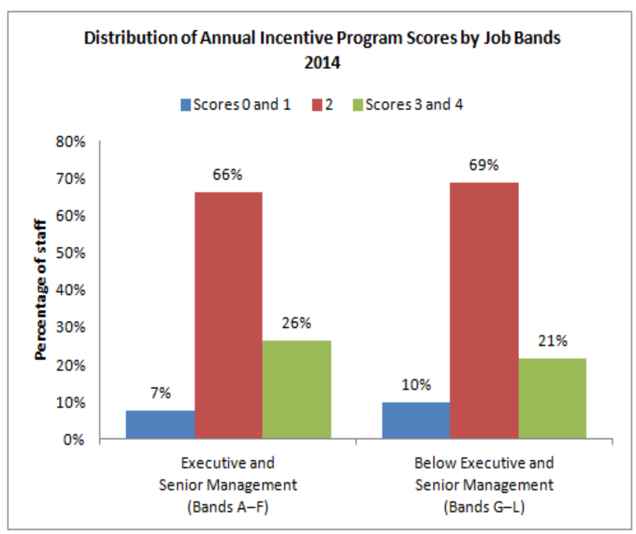
Staffing Levels

- Reductions were made to the number of senior management positions (Vice Presidents and Directors) with staff levels for this group decreased by 10.6 % over the period from 2012 to 2015.

Annual Incentive Program

- The distribution of Annual Incentive Program ("AIP") scores for bands A to F was improved to be more consistent with the target distribution percentages across the company (See Figure 1).





Findings and Recommendations

Some minor findings related to employee relocation costs were noted and recommendations were made to:

- Clarify and communicate to line managers which relocation expenses require Real Estate review and processing; and
- Implement a process to track, assess and report on the purchase guarantee program including consideration of all property carrying costs.

The findings noted in the report have been reviewed with management who has committed to specific action plans to address them. Please refer to Section 2.0 for details of the above findings along with the potential causes, impacts, recommendations and management action plans.

Opportunity for Improvement

During the audit there were 57 pay compression increases granted. While our testing of a sample of 25 noted that they were all within the guideline of 3% of the highest subordinate's salary, the guideline and approval process were not formally documented. As HR management continues to develop the new compensation structure, they should consider formally documenting guidelines for applying the pay compression and other adjustments.

2.0 DETAILED AUDIT FINDINGS

1. Selected relocation expenses were paid to employees without the review and processing by the Real Estate department and some related mileage expenses exceeded allowable amounts.	**Low**

Expenses relating to the sale, maintenance or mortgage of property associated with employee relocation require Real Estate review and processing for payment through a cheque request.

Expenses processed through the Concur Travel and Expense system for the period January 2014 to October 2015 were reviewed. We noted that from a sample of 25 employees selected, expenses for two employees totalling approximately $4K, included legal fees, property maintenance and mortgage interest on employee relocation-related properties. These expenses were processed and paid through Concur rather than being submitted for review and processing as a cheque request by the Real Estate.

Also, five employees were paid for mileage expenses that exceeded the allowable amounts of trips per month to and from the original residence. The estimated amount paid in excess for these employees was $21K (see Appendix A).

Potential Cause:
The employees erroneously submitted their relocation expense claims through Concur, rather than to the Real Estate Services councilor for processing as a cheque request. As such, Real Estate did not have visibility to expenses which were incorrectly processed and approved within the Concur Travel and Expense system.

Impact:
Relocation expense payments made without Real Estate's required review resulting in potential payments of ineligible or duplicate expenses.

Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Reinforce to the line managers which relocation expenses require review and processing as a cheque request through the Real Estate department and the line manager's responsibility for review and approval of mileage expenses in accordance with the Business Travel and Expense Standard.	Real Estate will work with Finance to remind line managers of the types of relocation expenses that must be processed through Real Estate and their responsibility for the proper approval of mileage expenses. Real Estate will also work with Finance to develop flags within Concur which will prompt the employee for secondary review on mileage expenses before payment. The intent is to flag anything that is not compliant with policy.	Ron Murphy Senior Manager, Real Estate Services December 1, 2016

2. Purchase guarantees on employees' relocation properties and carrying costs were not tracked.	**Low**

OPG will purchase a relocated employee's property that is not sold within a 90-day listing period if a purchase guarantee was offered to the employee. Real Estate will attempt to sell the property at a price as close as possible to the purchase guarantee and to limit any loss on the sale.

For the period May 2013 to October 2015, Internal Audit noted that 38 properties were sold which resulted in a total loss of $429K, approximately 4.3% of the total price OPG paid for the properties. However, information on the number of purchase guarantees offered relative to the number of properties purchased and sold under the purchase guarantee program was not readily available. Also, carrying costs or total cost per each relocation case were not tracked and were calculated by Real Estate on an ad hoc basis.

Potential Causes & Impact

Potential Cause:

- The system used to track the purchase guarantee information was not functioning and the information is only retained in each case file; and
- There was no automated way to calculate and report carrying costs and total cost.

Impact:

- Inability to assess the effectiveness of the purchase guarantee program including efforts to limit losses on the sale of property;
- Losses are viewed as unreasonable resulting in reputational consequences and financial impact to OPG; and
- Costs for each property are not fully assessed and completely reported.

Recommendations	**Management Action Plan**	**Owner & Target Completion Date**
Real Estate should consider implementing a simplified tool for tracking purchase guarantees offered and properties purchased under the program. Total costs including carrying costs should also be tracked. The effectiveness of the purchase guarantee program should be periodically assessed.	A process to track, assess and report on the purchase guarantee program including consideration of all property costs will be implemented.	Ron Murphy Senior Manager, Real Estate Services December 15, 2016

APPENDIX A-FINDINGS SUPPORT

1. Expenses paid in Concur by employee that were not reviewed by Real Estate.

Employee	Vendor	Date	Amount	Category
Employee 1	CIBC	2015/07/28	$385	Mortgage Interest
	Town of Atikokan	2015/07/28	$287	Property Tax
	Gary Sportack	2015/07/24	$178	Legal Fees
	Total			**$850**
Employee 2	Lawrence A Eustace	2015/07/14	$2,986	Legal Fees
	Lawrence A Eustace	2015/07/14	$219	Legal Fees
	Total			**$3,205**

2. Mileage expenses paid verses what was allowed. These mileage expenses were classified as relocation under Concur relocation policy module. The mileage was calculated based on round trip to and from the new location.

Employee	Personal Car Mileage	Average Distance	Amount Allowed	Variance
Employee 1	$9,667	512	$8, 192	$1,475
Employee 2	$8,888	This individual has not moved and is not actively looking therefore not eligible for mileage reimbursement		$8,888
Employee 3	$7,963	776	$4,656	$3,307
Employee 4	$6,394	666	$2,664	$3,730
Employee 5	$6,055	672	$2,352	$3,703
Total	**$38,967**	**2,626**	**$17,864**	**$21,103**

APPENDIX B - RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgement by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring “low risk” findings may be elevated to medium risk status.

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OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

Internal Audit

OEB Rate Application Audit

February 19, 2016

Report Rating: **Effective**

Distribution:

Chris Ginther
Senior Vice-President Legal, Ethics & Compliance

Andrew Barrett
Vice-President Regulatory Affairs

cc:	Jeffrey Lyash	President & Chief Executive Officer
	Glenn Jager	Nuclear President & Chief Nuclear Officer
	Mike Martelli	President Renewable Generation & Power Marketing
	Carlo Crozzoli	Senior-Vice President & Acting Chief Financial Officer
	Carla Carmichael	Vice-President Nuclear Finance
	Jody Hamade	Vice-President Enterprise Risk Management
	Lubna Ladak	Vice-President Hydro-Thermal Operations Finance
	Colin Anderson	Director Ontario Regulatory Affairs
	Janice Ding	Director Internal Audit
	Jenny Ruz	Director Controllership

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1.0 EXECUTIVE SUMMARY

1.1 Report Rating and Summary of Findings

Report Rating: **Effective**

No.	Finding	Risk Type	Risk Rating[1]		
			High	Moderate	Low
1	Guidance on prudence practices was not formally documented.	Operational			X
Total		**1**	**0**	**0**	**1**

1.2 Background

The April 2016 Ontario Energy Board ("OEB") rate application (the "Application") for the prescribed Hydroelectric and Nuclear generating facilities will cover the five year period from 2017 to 2021, as compared to past applications which were for a two year period. In addition, the company is required to propose an Incentive Ratemaking ("IR") Mechanism for the hydroelectric assets, and a cost of service approach (incorporating certain Custom IR elements) for the nuclear facilities. Upcoming major events, including Pickering extended operations and Darlington refurbishment, will be factored into the Application.

The Regulatory Affairs Department ("RAD") facilitates the OEB rate application process which requires substantial business unit support to prepare and present evidence for the Application. Cost prudence has historically been and continues to be a significant area of concern for the OEB in its decisions. These decisions have both financial and reputational impacts for OPG.

This audit was conducted as a follow-up on activities that have occurred since the last audit in late 2014 in preparation for the upcoming rate application.

1.3 Objective & Scope

The objective of this audit was to independently assess the design and operating effectiveness of the processes and controls necessary to demonstrate prudence in support of cost recovery for the 2016 OEB rate application. Key activities included:

- Following-up on lessons learned;
- Taking actions on OEB directives and deliverables; and
- Addressing strategic issues identified by RAD.

[1] Please refer to Appendix A for risk rating definitions

To achieve the audit objective, we have reviewed and tested, on a sample basis, whether:

A. Follow-up on Lessons Learned

Lessons learned were assessed and dispositioned, including:

- RAD provided guidance to facilitate business plan alignment, in direction with regulatory strategies (e.g. use of achievable production forecasts);
- Resource planning included formalization of succession plans for core witnesses and early communication of required resources to business units;
- External experts were engaged to supplement areas with skills shortage; and
- Training was upgraded to cover crafting of regulatory evidence, cross-examination challenges and participation at technical conferences.

B. OEB Directives and Deliverables

Board findings from the 2014 OEB decision (EB-2013-0321) including the following were actioned:

- Proposed incentive rate mechanisms incorporated the OEB renewed regulatory framework and results from productivity studies;
- New benchmark studies for hydroelectric, compensation and corporate support functions were performed; and
- Existing nuclear benchmarking studies were updated including results for productivity, capability factor and generation costs.

C. Strategic Issues

Focus was placed on strategic issues identified by RAD including:

- Balances in deferral and variance accounts (including amounts recoverable in future periods) were accurately accounted for;
- Actions were taken by business units to ensure Business Case Summaries ("BCS") for projects support the "used or useful" principle (i.e. assets were required, not merely in use) to further address OEB concerns over cost prudence; and
- Proposed rate smoothing mechanism was designed to moderate customer rate impacts while providing sufficient cash flow during the Darlington refurbishment period.

The scope included activities from October 2014 until January 2016. For required actions not yet completed during the audit timeframe, Internal Audit ("IA") reviewed plans for completion and assessed reasonability.

1.4 Conclusion

IA noted the following positive observations during audit execution:

- Rigorous plans were in place to screen and prepare witnesses for cross-examination during the hearings;
- Expertise of external consultants was leveraged to assist with crafting complex exhibits;
- Benchmarking data and lessons learned from industry peers were used in the development of Incentive Rate Mechanisms; and
- A structured approach was in place to prepare for project prudence reviews including the identification and analysis of relevant artifacts (i.e. business cases, contract documents, engineering reports) and key decision areas.

Finding & Recommendation
A minor finding was noted around the lack of documented guidance and communication on prudence practices that should be incorporated in future projects. Management should formally document the guidance on prudence which would help further integrate rate regulation principles into business planning and decision making.

The finding noted in this report was reviewed with management and they have committed to a specific action plan. Please refer to Section 2.0 for specific details of the above finding along with the associated risk impact, audit recommendations and management action plan.

2.0 DETAILED AUDIT FINDING

Internal Audit identified the following detailed finding and recommendation which has been risk rated based on the definitions outlined in Appendix A.

1. Guidance on prudence practices was not formally documented.	**Low**
Guidance on cost prudence evidence requirements such as use of economics, project justification, extent of detailed documentation to retain and major cost-related decision points should be provided to business unit ("BU") stakeholders as a reference when making decisions for significant spending and investments. While RAD regularly engages in prudence meetings and discussions with the BUs, the guidance provided was not formally documented. IA noted some guidance was documented and presented to the Niagara Tunnel project stakeholders and the ELT; however, this or similar guidance regarding major cost-related decision points (e.g. contracting strategy, renegotiations and enforcement of contract rights) and lessons learned from prudence reviews were not formally documented for sharing on future projects and similar major expenditures.	
Potential Cause & Impact	
<u>Potential Cause:</u> RAD felt the existing governance and practices (such as project management standards and the Organizational Authority Register, issues and claims meetings, and presentations to ELT, BU staff, and witnesses on prudence), in aggregate, were sufficient to communicate prudence information to stakeholders. <u>Impact:</u> • Knowledge and understanding of expectations to demonstrate prudent cost management may not be sustained; • Future projects may not benefit from prior prudence learnings and OEB prudence concerns may repeat which can result in disallowances; and • Additional efforts may be required to develop documentation to demonstrate prudence during the rate application process which may be challenging if significant staff turnover has occurred and time has elapsed.	

Recommendation	**Management Action Plan**	**Owner & Target Completion Date**
Formally document and communicate the guidance on prudence, including key decision areas, lessons learned, etc.	RAD is receptive to bolstering existing governance and practices with a specific formal document which will help progress OPG's maturity level on integrating rate regulation principles into business decision making.	Colin Anderson, Director, Ontario Regulatory Affairs October 31, 2016

APPENDIX A – RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgment by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

Internal Audit

Business Transformation Post-Implementation Review

May 17, 2016

Report Rating: **Generally Effective**

Distribution:

Ken Hartwick
SVP Finance, Strategy, Risk & Chief Financial Officer

Scott Martin
SVP Business & Administrative Services

Jaffar Husain
Director Business Transformation Projects

cc:	Jeff Lyash	President & Chief Executive Officer
	Barb Keenan	SVP People, Culture & Communications
	Carlo Crozzoli	SVP Corporate Business Development & Chief Risk Officer
	Mike Martelli	President HTO, Renewable Generation & Power Marketing
	Glenn Jager	Chief Nuclear Officer
	Jody Hamade	Vice President Enterprise Risk Management
	Nicolle Butcher	Vice President Business & Services (Nuclear)
	Janice Ding	Director Internal Audit

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1.0 EXECUTIVE SUMMARY

1.1 Report Rating and Summary of Findings

Report Rating: **Generally Effective**

No.	Finding	Risk Type	High	Moderate	Low
1	BT initiatives lack measurement criteria for individual activities.	Operational		X	
2	Some efficiency gains reported by business units were not directly supported by the documentation included in the project close-out forms.	Operational			X
Total			**-**	**1**	**1**

1.2 Background

In 2011, OPG initiated a Business Transformation ("BT") initiative which was consistent with its commitment to meeting ratepayers' expectations of being a safe, efficient and low-cost electricity generator. A key objective of the BT initiative was to better align OPG's future cost structure with projected revenues.

Through the BT initiative, management sought to reduce the level of effort undertaken within various business functions to achieve key business objectives, while still maintaining the same level of overall service. The "efficiency gains" resulting from this exercise were intended to align the aggregate level of effort associated with OPG's key business processes with the organization's shrinking workforce (arising from impending retirements and attrition).

Management has indicated that the following accomplishments will be, or have been, realized as a result of BT:

- Through attrition, savings of an estimated $1 billion over six years (2011- 2016), achieved by reducing the overall headcount by 2,330 or 20% of 2011 levels;
- Reduction in the number of managers and a decrease in total base salary costs for management by 9% compared to 2010 levels; and
- Consolidation of activities under a centre-led organizational model designed to use resources more efficiently and avoid low-value activities and duplication of work.

The elements listed above were delivered through the development and execution of various initiatives and related charters specific to individual business units. As initiatives were completed, initiative owners were required to document the actions taken, efficiency gains achieved and attest to the completion of the initiative using "close-out forms" which were then submitted to a sponsoring Executive Leadership Team ("ELT") member for acceptance.

Of the over 130 BT initiatives, all but four were closed by the end of Q1 2016 (refer to Appendix B for a list of the open initiatives). The status of these remaining open initiatives continues to be monitored.

1.3 Objective & Scope

The objective of this audit was to verify that the BT activities undertaken to achieve the related initiatives were implemented and sustained; the actual realized efficiency gains were as reported in the close-out forms; and open BT initiatives continue to be tracked to target.

In order to achieve the audit objective, IA worked with management to understand the processes undertaken to review the BT initiatives, validate resulting efficiency gains, and, on a sample basis, tested whether:

A. Goals and Savings

Efficiency gains created through BT initiatives (as reported through close-out forms) were substantiated by relevant supporting information and are being sustained as at the time of the audit, specifically:

- o Efficiency gains were realized according to targets and incorporated into business plans;
- o Low-value work activities were eliminated while sustaining core functions; and

- Processes exist within Business Units to monitor BT initiatives not yet completed.

B. Sustainability

- BT principles have been maintained through the development of OPG's new business strategies and operating goals, as evident in 2016 business plans; and
- Management developed and implemented actions to address the recommendations resulting from the 2014 PricewaterhouseCoopers ("PwC") BT report.

The scope of the audit included all BT initiatives and processes with the exception of Human Resources ("HR") processes related to compensation and hiring, as they were covered as part of 2015 Internal Audit ("IA") reviews.

1.4 Conclusions

Based on IA's review of a sample of BT initiatives, we were able to validate that the efficiency gains stated in the close-out forms were achieved and are being sustained. In addition, management is continuing to effectively track the remaining BT initiatives.

<u>Positive Practices Observed</u>

- Regular updates are obtained from the BT initiative owners and reported to the ELT. Delays are being reported and approved to ensure timely achievement of the BT initiatives;

- Upon completion of BT initiatives, close-out forms are being completed, accepted and approved by ELT members, and reported to the ELT and BT Executive / BT Portfolio Management Team. These forms are being maintained centrally to ensure adequate tracking of the overall program;

- Management has demonstrated a commitment to ensuring the achievement of BT; proactively commissioning an independent review to assess BT's strategy and execution. The recommendations identified by the third party (PwC) have been addressed by management; and

- Management has committed to sustaining the BT principles over the coming years; evident in the 2016 business plans which incorporate these principles as part of the business strategies and operating goals.

Findings and Recommendations

We noted a lack of an overall defined approach or guidance for Business Transformation targets. As a result, there was a lack of consistency in terms of measurability of objectives across BT initiative charters and with respect to how the initiatives' close-out reporting was supported:

- Although the individual initiative charters set out general objectives, it was not always clear how each planned activity would specifically and measurably contribute to the achievement of a targeted overall efficiency gain.

- At the onset of BT, guidance was not provided to BT initiative owners on how to substantiate and document the achievement of efficiency gains reported in the close-out forms or clearly link the savings to an overall change in the global cost structure.

When establishing objectives as part of future initiatives and programs, OPG should create guidelines to ensure individual initiative objectives are specific and measurable, and to ensure consistency in terms of measurement and support for achievement of results. This will better allow OPG to substantiate whether the efficiency gains stated as having been achieved have, in fact, been achieved; and will provide senior management with the required assurance when reporting efficiency gains in official documents, public statements and news releases.

The findings noted in this report have been reviewed with Management, who has committed to specific action plans. Please refer to Section 2.0 for specific details of the above findings, along with the associated risk impact, recommendations and management action plans.

Opportunity for Improvement

In 2014, PwC was engaged to perform a review of the BT strategy and execution. Although management addressed the resulting recommendations, the specific remediating action plans accountabilities and timelines were not formally documented and communicated. To ensure the effective response to future reviews and recommendations on future significant company-wide initiatives, action plans with accountabilities and timelines should be developed, documented and tracked to completion.

2.0 DETAILED AUDIT FINDINGS

Internal Audit identified the following detailed findings and recommendations, which have been risk rated based on the definitions outlined in Appendix C.

<table>
<tr><th colspan="2">1. BT initiatives lack measurement criteria for individual activities.</th><th>Moderate</th></tr>
<tr><td colspan="3">At the inception of the BT program, charters for the individual BT initiatives were created by the responsible business units and initiative owners. These charters outlined the initiatives' objectives and the activities which were planned to be undertaken to meet those objectives.

While the company had adjusted the overall cost structure downward to reflect the expected savings from BT, the charters lacked specific detail to describe how the planned efficiency gains would be achieved on a case-by-case basis. For example, an initiative charter may have stated that an efficiency gain of a target number of FTEs would be achieved by undertaking various activities; however, it was not clear how much of an efficiency gain would be achieved by each individual activity that made up the initiative. As a result, it was not always possible for Internal Audit to substantiate that the planned efficiency gains per the charters had been achieved – rather, we assessed whether the actions stated as having been completed per the close-out forms were completed and remain in place. Business Plans were then used to validate overall staffing reductions.</td></tr>
<tr><th colspan="3">Potential Cause & Impact</th></tr>
<tr><td colspan="3"><u>Potential Causes:</u>
• The lack of a standardized, prescriptive approach to defining BT initiatives, including specifically how the expected efficiency gains would be realized.
<u>Impacts:</u>
• Lack of specific and measurable goals (i.e. charter objectives) makes it difficult to substantiate that the planned efficiency gain has been realized, and therefore creates the risk that OPG reporting is not accurate.</td></tr>
<tr><th>Recommendation</th><th>Management Action Plan</th><th>Owner &
Target Completion Date</th></tr>
<tr><td>For future initiatives / programs, OPG should ensure objectives are specific and measurable; define a consistent approach to measurement; and establish guidelines for the completeness, format and retention of information required to demonstrate the achievement of claims made.</td><td>For future initiatives / programs, we will ensure upon acceptance that goals are specific and measurable, that is: it is clear how cost savings, efficiency gains or other will be achieved, and such achievement will be quantifiable / measurable.</td><td>Scott Martin - SVP Business & Administrative Services

Date: Completed</td></tr>
</table>

2. Some efficiency gains reported by business units were not directly supported by the documentation included in the project close-out forms.	**Low**

OPG has publicly reported BT efficiency gains based on the achievements reported within the close-out forms. Therefore, the completeness and accuracy of these forms is critical to ensure accurate external reporting by OPG. Sufficient evidence must be available to the initiative owners and ELT members to independently confirm the results.

For 17 of the 20 completed BT initiatives reviewed as part of this audit (refer to Appendix A for a listing of initiatives sampled), the related close-out package provided by the BT Portfolio Management Team contained inadequate evidence or did not make reference to specific internal supporting documents to confirm the stated efficiency gains. In each of these 17 cases, additional documentation had to be gathered from initiative owners and/or corporate functions to substantiate the claimed efficiency gains. For example, close-out packages did not always contain or refer to organizational charts, business plans or other documentation to support full time equivalent ("FTE") efficiency gains. In other cases, the close-out packages did not clearly demonstrate the establishment of centre-led organizational models.

As a result, the nature and format of supporting documentation submitted and retained with the close-out forms to demonstrate achievement of the efficiency gains differed across initiatives.

Potential Cause & Impact

Potential Causes:

- The lack of a standardized, prescriptive approach to defining and measuring efficiency gains (refer to Observation 1 within this report); and
- The close-out form template is not prescriptive with respect to the type or detail of supporting documentation to be submitted to and retained by the BT Portfolio Management Team.

Impacts:

- Failure to maintain adequate documentation to support the claims made within BT close-out forms makes it difficult for the ELT to demonstrate that they have appropriately reviewed the close-out forms, and, as a result, the efficiency gains documented within; and
- A lack of central organization and retention of supporting BT information (particularly for closed initiatives) could lead to loss of documented support for the efficiency gain claims upon the departure of initiative owners or other key personnel.

Recommendation	Management Action Plan	Owner & Target Completion Date
For the four remaining BT initiatives open as at Q1 2016, the BT Portfolio Management Team should ensure sufficient documentation is retained or referred to by the close-out forms. They should be clear on the actions completed to support the completion of all activities undertaken in relation to the efficiency gains reported (see Appendix B for a list of these initiatives).	Communication will be sent to the initiative owners left to complete their project close-out charters on the level of detail expected to substantiate BT savings.	Jaffar Husain - Director Business Transformation Projects May 31, 2016

APPENDIX A - INITIATIVES SAMPLED

As part of this audit, we reviewed 20 initiatives reported as "closed" as at December 31, 2015. Close-out form details regarding these samples are provided below.

No.	Initiative Name	Initiative Number	Close Date	Sufficient Documentation Retained with Close-Out Form?	Sufficient Documentation Available with Management?
1	Optimization and Elimination of duplication of Services – Document Management	BAS-IT-07	Oct 30, 2015	No	Yes
2	Optimization and Elimination of duplication of Mail / Administration Services	BAS-ES-06	Mar 29, 2015	No	Yes
3	Security Search Equipment Replacement	NUC-038	Jan 15, 2016	No	Yes
4	Adaptive Resourcing of ANSO / NSO	NUC-040	Dec 15, 2015	No	Yes
5	Consolidate Common Training Content	P&C-32	Jun 1, 2015	No	Yes
6	New HR Business Partner Model	P&C-27	Nov 30, 2015	No	Yes
7	Reduce Effort to Oversee Vendors	NUC-041	Feb 2015	No	Yes
8	Coal Closure Cost Mitigation	HT-14	Apr 14, 2015	No	Yes
9	Reduction of Non-Regulated Security Services	NUC-039	Jan 15, 2016	No	Yes
10	Training - Support & Planning Consolidation	P&C-28	Jun 1, 2015	No	Yes
11	Print Plant Consolidation / Audio Visual Services	BAS-ES-05	Jun 30, 2015	No	Yes
12	Centralization of Accounting (into Shared Financial Service Centre)	FIN-05	Mar 31, 2015	No	Yes
13	Complete Development of the Communication Services Group	CO-SR-013	Mar 31, 2015	No	Yes
14	Service Level Reduction (Library)	BAS-ES-04	Aug 31, 2015	No	Yes
15	Efficiency Improvements to Treasury Operations (Insurance)	FIN-16	N/A – this initiative was cancelled/not pursued.	Yes	Yes

No.	Initiative Name	Initiative Number	Close Date	Sufficient Documentation Retained with Close-Out Form?	Sufficient Documentation Available with Management?
16	Plan, Negotiate, and Transition to Next OPG IT Outsource Contract	BASIT-006	N/A – this initiative was cancelled/not pursued.	Yes	Yes
17	Optimize In-House Drawing Modifications	NUC-016	Sep 25, 2013	No	Yes
18	Create COE for Components Engineering	NUC-003	Jan 31, 2014	Yes	Yes
19	Supply Inspection Rationalization	BAS-NSC-03	Dec 31, 2013	No	Yes
20	Outsource Disability Case Management	P&C-08	Mar 31, 2014	No	Yes

APPENDIX B - OPEN BT INITATIVES AS AT Q1 2016

The remaining BT initiatives being tracked to completion as at the end of Q1 2016 are as follow:

Initiative Name	Initiative Number	Close Date
Days Based Maintenance Implementation	BAS-NSC-11	Apr 30, 2016
Assistant Procurement Specialist	BAS-NSC-14	Dec 31, 2016
Nuclear Warehouse Initiatives - Staging Strategy	BAS-NSC-18	Dec 31, 2016
Model Work Permit Element Efficiencies	NUC-046	Dec 31, 2016

APPENDIX C - RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgment by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

OPG CONFIDENTIAL

Internal Audit

SMART Objectives Follow-up Audit

September 29, 2016

Report Rating: **Requires Improvement**

Distribution:

Barb Keenan
SVP, People, Culture & Communications

Nicole Lichowit
VP, Talent Management & Business Change

cc:	Jeffrey Lyash	President and Chief Executive Officer
	Glenn Jager	Nuclear President and Chief Nuclear Officer
	Mike Martelli	President Renewable Generation & Power Marketing
	Chris Ginther	SVP Legal, Ethics & Compliance
	Ken Hartwick	SVP Finance, Strategy, Risk & Chief Financial Officer
	Scott Martin	SVP Business & Administrative Services
	Dietmar Reiner	SVP Nuclear Projects
	Catriona King	VP Corporate Secretary
	Jody Hamade	VP Enterprise Risk Management
	Janice Ding	Director Internal Audit
	Jennifer Huinink	Director Talent & Business Change
	Jennifer Ruz	Director Controllership

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1.0 EXECUTIVE SUMMARY

1.1 Report Rating and Summary of Findings

Report Rating: Requires Improvement

No.	Finding	Risk Type	Risk Rating[1]		
			High	Moderate	Low
1	Forty-three percent (43%) of Performance Planning and Review ("PPR") Plans did not have a minimum of three SMART performance objectives.	Operational	X		
Total		**1**	**1**	**-**	**-**

1.2 Background

SMART is defined as Specific, Measurable, Achievable, Relevant & Realistic and Time-bound. In order to provide clarity in performance objectives and establish a strong link between incentive awards and staff performance, OPG Management Group ("MG") employees are required to have at least three of their 2016 performance objectives developed using the SMART framework.

Internal Audit ("IA") performed an audit on SMART objectives in Q2-2016. The audit was rated "Not Effective", only 36% of the 2016 Performance Planning and Review ("PPR") Plans sampled were found to have at least three objectives sufficiently aligned with the SMART framework. Subsequent to the release of the audit report, OPG's President & CEO requested that all MG employees' 2016 PPR Plans be reviewed and adjusted as necessary by July 31, 2016 to have a minimum of three SMART objectives.

People, Culture & Communications ("PC&C") developed various actions to address the finding, which included providing additional communication to People Leaders (Band G and above) to clarify the expectations for SMART objectives, enhancing guidance and examples available on PowerNet and rolling out the SMART Objectives Learning Session. While mandatory attendance of the SMART Objectives Learning Session by MG employees is a longer term action designed to address the 2017 performance objectives planning process, approximately 50% of MG employees had already completed the session by July 31, 2016.

This follow-up audit was performed to assess whether the issues identified in the Q2-2016 audit had been resolved satisfactorily in the adjusted 2016 PPR Plans by MG employees.

1.3 Objective & Scope

The objective of this audit was to assess whether MG employees' performance objectives were set based on SMART principles, as per the requirements outlined in the President & CEO's email dated June 2, 2016 (i.e. "each MG employee has a minimum of three performance objectives following SMART Framework").

[1] Please refer to Appendix B for risk rating definitions

The scope covered performance objectives set by MG employees for 2016 – documented in the PPR system by July 31, 2016. Testing of these PPR Plans was performed on a sample basis to assess the level of compliance with SMART principles.

The following were excluded from the scope of the audit:

- Performance objectives / scorecards for the Executive Leadership Team ("ELT"), which were reviewed by the Enterprise Risk Management ("ERM") group and reported to the Compensation, Leadership and Governance Committee, a subcommittee of the Board of Directors; and
- Performance objectives / scorecards for unionized employees.

Fraud Risk Considerations: no fraud risk areas were identified.

1.4 Testing Methodology

- Fifty PPR Plans were sampled, stratified across all Business Units and Band levels;
- Three objectives that were most aligned to the SMART framework were selected from each PPR Plan for evaluation; and
- All PPR Plans that did not pass the SMART Objectives audit in Q2-2016 were also re-tested.

1.5 Conclusion

IA examined a sample of 82 PPR Plans, which included the 32 PPR Plans that did not pass the SMART Objectives audit performed in Q2-2016. Overall, 57% of PPR Plans examined had met the "minimum of three" SMART requirement. This was a substantial improvement from the Q2-2016 SMART Objectives audit, where only 36% of the PPR Plans sampled had met the requirement. The positive trend reflected the impact of PC&C's management actions implemented to date, which included enhanced communication and guidance to MG employees (e.g. additional SMART examples on PowerNet, rollout of the SMART Objectives Learning Session).

For the 43% of PPR Plans examined (35 of 82) that did not meet the "minimum of three" SMART requirement, breakdown of the exceptions by Business Units are summarized below:

Business Unit / Group	Retests			New Samples			Total		
	Tested	Pass	Fail	Tested	Pass	Fail	Tested	Pass	Fail
Legal/Ethics & Compliance	3	3	-	-	-	-	3	3	-
Finance	7	4	3	2	2	-	9	6	3
People/Culture & Communications	7	4	3	6	5	1	13	9	4
Business & Admin Services	1	1	-	4	4	-	5	5	-
Total Corporate Functions	**18**	**12**	**6**	**12**	**11**	**1**	**30**	**23**	**7**
Nuclear	11	2	9	25	9	16	36	11	25
Renewable Generation & Power Marketing	3	2	1	13	11	2	16	13	3
Total	**32**	**16**	**16**	**50**	**31**	**19**	**82**	**47**	**35** *
Total %	**100%**	**50%**	**50%**	**100%**	**62%**	**38%**	**100%**	**57%**	**43%**

* PPR Plans with less than three SMART performance objectives and the criteria failed are set out in Appendix A.

The following key gaps were identified in this follow-up audit:

- Instances were noted where employees had not identified individual actions to be taken that would contribute to the achievement of corporate or business unit level objectives (e.g. An individual's goal would be stated as the Corporate All Injury Rate target or Business Unit's annual budget). Individual actions should have been included to meet the "Specific" and "Achievable" criteria; and

- Employees had not defined the specific timeframes for the measures / objectives in order to meet the "Time-Bound" criteria.

PC&C management should provide feedback to People Leaders so that the exceptions noted in this follow-up audit are communicated to the individuals for remediation.

PC&C management is continuing its efforts to reinforce the SMART requirements with MG staff and implement the remaining action plans that were developed in response to the Q2-2016 SMART Objectives audit. Key actions included mandatory attendance of the SMART Objectives Learning Session by MG employees by March 31, 2017, as well as the performance of quality assurance review over 2017 PPR Plans (sample-based) by June 30, 2017.

APPENDIX A – PPR PLANS WITH LESS THAN 3 SMART OBJECTIVES

Business Unit / Group	Employee #	Performance Objective #	Criteria Failed					Retest / New Sample
			S	M	A	R	T	
Finance	***001	2	X		X			Retest
	***181	2	X	X				Retest
	***677	3		X			X	Retest
Finance – Total # Failed								**3**
People/Culture & Communications	***830	1	X		X			Retest
	***564	2					X	Retest
	***364	5		X		X	X	Retest
	***162	1					X	New
		2		X			X	
		5		X			X	
People/Culture & Communications – Total # Failed								**4**
Nuclear	***223	6	X					Retest
	***995	4					X	Retest
	***453	2		X			X	Retest
		4					X	
	***880	1	X		X	X		Retest
		2	X		X	X		
		3	X	X			X	
	***401	6	X				X	Retest
		9	X				X	
	***244	2	X		X	X		Retest
		3	X		X	X		
		5			X	X		
	***823	3	X		X			Retest
	***125	4	X	X			X	Retest
	***736	5			X	X		Retest
		6	X					
	***940	6	X					New
	***021	1	X		X			New
		2	X		X			
		6	X		X			
	***405	2	X		X	X		New
		3	X		X			
		4	X		X	X		
	***949	3	X		X			New
		5	X					

Business Unit / Group	Employee #	Performance Objective #	Criteria Failed					Retest / New Sample
			S	M	A	R	T	
Nuclear	***361	2					X	New
		3		X				
	***923	5				X		New
		6	X					
	***974	2	X		X			New
		3	X		X			
	***331	3	X	X				New
	***507	4	X			X		New
		9	X		X	X		
	***211	3					X	New
		4					X	
	***998	1	X		X			New
	***350	1	X		X			New
	***115	3	X		X			New
		4	X		X			
		6	X		X			
	***591	2	X		X			New
		3	X		X			
	***860	6	X					New
	***353	1	X		X			New
		2	X		X			
Nuclear – Total # Failed								**25**
Renewable Generation & Power Marketing	***697	3	X	X			X	Retest
	***901	1		X			X	New
		3		X			X	
	***621	3					X	New
		4					X	
Renewable Generation & Power Marketing – Total # Failed								**3**
Total								**35**
Total % (out of 82 samples)								**43%**

APPENDIX B – RISK RATING DEFINITIONS FOR AUDIT FINDINGS

Ratings are derived through professional judgment by the audit team and discussion with management. The ratings for individual control findings are outlined below.

Rating	Definition
High Risk	The finding presents a risk that could potentially have severe/major impact on financial sustainability (≥$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations.
Moderate Risk	The finding presents a risk that could potentially have a moderate impact on financial sustainability ($500K to <$5M), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. If not remediated, this risk could escalate to high risk.
Low Risk	The finding could potentially have a minor impact on financial sustainability (<$500K), operational excellence, project excellence, safety, environment and reliability, reputation, regulatory relationship, or compliance with laws and regulations. Recurring "low risk" findings may be elevated to medium risk status.

OVERALL REPORT RATING SCALE

An overall report rating has been assigned as an indication of the overall design, existence and effectiveness of the components of the internal control structure that was subject to the internal audit. The internal audit rating should be considered in conjunction with the definitions noted above.

- *Effective:* control and risk management practices provide reasonable assurance that business process objectives will be achieved and may include minor improvements and/or opportunities for improvement.
- *Generally Effective*: control and risk management practices require more than minor but less than significant improvements to provide reasonable assurance that business process objectives will be achieved.
- *Requires Improvement*: control and risk management practices require significant improvements in high risk and/or core areas to provide reasonable assurance that business process objectives will be achieved.
- *Not Effective:* control and risk management practices are not designed and/or are not operating effectively.

UNDERTAKING JT3.5

Undertaking

TO CONFIRM CONCENTRIC'S ASSUMPTION RE: THE VALUE LINE DATA.

Response

This response has been prepared by Concentric Energy Advisors.

Concentric did not rely on Value Line's generation source data in developing Exhibit C1-1-1, Attachment 1. Staff-011, however, characterized certain generation data from Value Line as being representative of "nameplate capacity." In reviewing Value Line reports, it was not evident as to whether Value Line's "generation sources" were reflective of nameplate capacity or some other metric. Concentric, therefore, made an inquiry of Value Line as to the definition of "generation sources" in the Value Line reports, and reported our findings in the interrogatory response.

UNDERTAKING JT3.6

Undertaking

TO PROVIDE CONCENTRIC'S RESPONSE TO MR. SHEPHERD'S QUESTION ABOUT WHETHER AN ASYMMETRICAL POSITIVE RISK EXISTS

Response

This response was prepared by Concentric Energy Advisors.

The ability to stay out of a rate setting proceeding for an additional year may have option value to OPG (albeit limited, based on the OEB's ability to request OPG to reapply for payment amounts), but is not necessarily a source of risk mitigation. In addition, the decision to not re-apply for payment amounts is not driven entirely by the ability to earn a forecast rate of return, but rather may also be affected by other, practical planning factors. In OPG's case, those factors have included adding newly regulated hydroelectric assets prior to EB-2013-0321, and, leading up to this proceeding, decision-making around Pickering extended operations, and the finalization of the Darlington Refurbishment Project release quality estimate. As stated in response to Ex. L-03.1-1 Staff-019 (c), for any period where a regulated utility does not match its expected costs with expected revenues it is exposed to the risk of cost under-recovery. That risk increases over a longer rate-setting period, all else being equal.

UNDERTAKING JT3.7

Undertaking

TO ADVISE OF THE TOTAL BUDGETED COST OF THE CONCENTRIC PROJECTS AND WITH THE CURRENT COST OVERRUNS WHAT THE NEW BUDGET FIGURE IS. (WITHDRAWN)

Response

The amount billed through the end of October is approximately $325,000. The remainder of Concentric's work related to the "Common Equity Ratio for OPG's Regulated Generation" report will involve responding to undertakings, reviewing OEB Staff and intervenor evidence, preparing interrogatories, and appearing at hearing for oral testimony. Such work will be performed on a time and materials basis and will depend on the number of undertakings, scope, and number of intervenor testimonies, and length of appearance at hearing. The estimate for the combination of the cost of the initial work, the current work and expected work with respect to this proceeding is approximately $450,000.

UNDERTAKING JT3.8

Undertaking

TO INQUIRE WITH TOWERS WATSON AS TO WHETHER THEY CAN INCLUDE THE EXCLUDED GRANDFATHERED DATA IN THEIR ANALYSIS AND WHETHER THAT WOULD BE AN APPLES-TO-APPLES COMPARISON OR NOT.

Response

OPG has been informed by Willis Towers Watson that the pension and benefit analysis could be re-run to capture OPG's grandfathered data; however, Willis Towers Watson does not have the data that would capture the equivalent grandfathered data for comparators. Therefore, it would be an "apples-to-oranges" comparison.

Redoing the analysis on this basis would have no value added given that the data will not provide for a meaningful comparison for evaluating the current market competitiveness of OPG's pension and benefit arrangements.

Willis Towers Watson has confirmed that it is standard practice to exclude grandfathered benefit elements and only look at benchmarking current and go-forward elements (i.e. those provided to new hires only), as it would be impractical for each organization to provide sufficient detail on every grandfathered arrangement and as the participation in grandfathered plans would vary widely across organizations.

UNDERTAKING JT3.9

Undertaking

FOR NUCLEAR AUTHORIZED MANAGEMENT GROUP, TO SPLIT THAT OUT BETWEEN THE ONES THAT ARE AT 75TH PERCENTILE AND THE ONES THAT ARE AT 50TH PERCENTILE.

Response

Figure 1 below provides the requested split.

Figure 1

OPG Group and Segment	# OPG Matched Incumbents	% +/- Target Market Base Salary	% +/- Target Market TDC
Management Group			
Nuclear Authorized (Senior Executives - 50th Percentile Target)	4	-29%	-63%
Nuclear Authorized (All other roles - 75th Percentile Target)	33	-15%	-7%
Overall Nuclear Authorized Management Group	**37**	**-18%**	**-27%**

Note: Target positioning for roles in the Nuclear Authorized segment is the 75th percentile, except for Senior Executive roles which target the 50th percentile.

UNDERTAKING JT3.10

Undertaking

TO PROVIDE A BREAKDOWN OF THE CHANGES TO THE BRUCE LEASE AND ANCILLARY AGREEMENTS THAT HAVE A MATERIAL IMPACT ON THE RATEPAYERS' RISK GOING FORWARD TO THE EXTENT OPG FEELS COMFORTABLE, OR IF NOT, TO SAY WHY NOT

Response

The key changes to the Bruce lease and ancilliary agreements (collectively, Bruce Lease) are listed at Ex. G2-2-1, p. 2, lines 17 to 25 and discussed further in Ex. G2-2-1, sections 3 and 4. Discussed below, these changes reflect a set of constructs negotiated by OPG and Bruce Power in the context of the Province's need to fully consider the economics of Bruce Power's proposed refurbishment and, presumably, inform the negotiations of the associated refurbishment contract, to which OPG is not a party. As noted at Day 3 of the Techinical Conference by Mr. Mauti (transcript p. 56), some of the constructs are different from the previous terms of the Bruce Lease and cannot be definitively assessed as having higher risk or lower risk. Moreover, as discussed below, attempts at such an assessment would require speculation on the outcomes of negotiations that would have needed to take place under the previous terms of the agreement related to the resetting of certain fees at the outset of the renewal periods in 2019.

1) Bruce Power's lease renewal term options have been extended by approximately 20 years, with renewal term base rent payments, which are intended to cover "executory costs", now subject to CPI escalation starting in 2019. Previously, the renewal term payments were not subject to CPI escalation, which means that rent payments have increased in the renewal period. Base rent payments to the end of 2018 have not changed.

2) Starting in 2016, supplemental rent will be in the form of per bundle used fuel fees, instead of a lump sum amount per operating unit subject to an annual rebate (discussed in (3) below). Volumetric fees will continue for low and intermediate level waste (L&ILW) management services. Both used fuel fees and L&ILW fees will be based on Ontario Nuclear Funds Agreement (ONFA) cost estimates and be subject to an update commensurate with the ONFA reference plan update process. Any resulting future adjustments to the ONFA-based cost estimates for used fuel and L&ILW generated after 2015 will trigger a cumulative true up of revenues calculated retroactively to January 1, 2016.

   The previous terms of the Bruce Lease provided for a one-time resetting of the L&ILW fees as well as the used fuel fee component of supplemental rent at the outset of the renewal term period, to be in effect from 2019 to the end of the renewal term in 2043 (now extended to 2064) without true up provisions. Given the absence of true up provisions under the previous terms of the agreement, it would have been necessary to negotiate a risk premium upon resetting of these fees for the duration of the lease renewal term. While it is not possible to know the outcome of the negotiation process that did not take place, OPG believes that the new provisions provide an objective, verifiable basis for determining supplemental rent and waste fees and serve to limit OPG's longer-term exposure to changes in cost estimates over the remaining term of the lease.

3) In conjunction with being replaced with volumetric fees as discussed in 2), effective December 4, 2015, supplemental rent is no longer subject to an annual reduction (rebate) based on HOEP levels (i.e. where annual arithmetic average of the HOEP fell below $30/MWh), which gave rise to embedded derivative impacts in accordance with US GAAP. This change led to the reversal of the derivative liability in December 2015 of approximately $299M (approximately $224M after tax), triggering a ratepayer refund of $68.6M through the rate riders proposed in this Application.[1] Overall, this change eliminated OPG's future exposure to an obligation based on the market clearing price

[1] As noted at Ex. G2-2-1, p. 9, lines 15-20, this refund represents the credit balance expected in the Bruce Lease Net Revenues Derivative Sub-Account at the end of 2016, largely on account of the amount OPG has been authorized to collect for the Bruce Derivative for the period from December 4, 2015 to the end of 2016 through the EB-2014-0370 rate riders currently in effect.

UNDERTAKING JT3.11

Undertaking

TO PROVIDE THE RESPONSE IN L-9.7-15 SEC 93 BROKEN DOWN IN ONE-YEAR PERIODS.

Response

This undertaking has requested the information in Ex. L-9.7-15 SEC-93 broken down into one year periods.

The rate smoothing model underpinning this application is based on the proposed annual revenue requirements for 2017-2021 (Ex. I1-1-1 table 1, line 26), and five-year averages of estimated revenue requirements and production forecasts for the 2022-2036 period. These indicative five-year averages were calculated using average rates and production for the 2022-2036 period absent rate smoothing, as provided in Ex. A1-3-3 Page 7, Chart 2.

As such, the annual rate underpinning the five-year averaged indicative rates provided in Ex. L-9.7-15 SEC-93 does not provide any additional information, as the model uses the same average rate for each year within each five-year period. The annual analysis underpinning this application is provided in Attachment 1, Table 1.

OPG has provided the annual net revenue deferred/recovered, interest during the period and period end Rate Smoothing Deferral Account Balance amounts (collectively, the “outputs”) using indicative annual revenue requirement and production amounts, rather than the five-year averaged indicative amounts used in the rate smoothing model. The annual revenue requirement and production amounts and resulting outputs are provided on an annual basis in Attachment 1, Table 2.

Table 1
Five-Year Revenue Requirement, Production, Average Rate, and Rate Smoothing Deferral Account Activity

Line No.		2017	2018	2019	2020	2021	2017-2021
		(a)	(b)	(c)	(d)	(e)	(f)
1	Anticipated Revenue Requirement ($BN)	$ 3.2	$ 3.2	$ 3.3	$ 3.8	$ 3.5	$ 17.0
2	Anticipated Production (TWh)	38	38	39	37	35	$ 188
3	Average Rate ($/MWh)	$ 84	$ 84	$ 84	$ 101	$ 99	$ 90
4	Smoothed rate ($/MWh)	$ 66	$ 73	$ 81	$ 90	$ 100	$ 82
5	Net Revenue Requirement Deferred/Recovered ($BN)	$ 0.7	$ 0.4	$ 0.1	$ 0.4	$ (0.0)	$ 1.6
6	Interest During Period ($BN)	$ 0.0	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 0.3
7	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 0.7	$ 1.2	$ 1.4	$ 1.8	$ 1.9	N/A

Line No.		2022	2023	2024	2025	2026	2022-2026
		(a)	(b)	(c)	(d)	(e)	(f)
8	Anticipated Revenue Requirement ($BN)	$ 3.6	$ 3.6	$ 3.6	$ 3.6	$ 3.6	$ 18.1
9	Anticipated Production (TWh)	26	26	26	26	26	$ 130
10	Average Rate ($/MWh)	$ 139	$ 139	$ 139	$ 139	$ 139	$ 139
11	Smoothed rate ($/MWh)	$ 111	$ 123	$ 137	$ 152	$ 168	$ 138
12	Net Revenue Requirement Deferred/Recovered ($BN)	$ 0.7	$ 0.4	$ 0.1	$ (0.3)	$ (0.8)	$ 0.1
13	Interest During Period ($BN)	$ 0.1	$ 0.2	$ 0.2	$ 0.2	$ 0.2	$ 0.8
14	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 2.7	$ 3.3	$ 3.5	$ 3.4	$ 2.8	N/A

Line No.		2027	2028	2029	2030	2031	2027-2031
		(a)	(b)	(c)	(d)	(e)	(f)
15	Anticipated Revenue Requirement ($BN)	$ 3.6	$ 3.6	$ 3.6	$ 3.6	$ 3.6	$ 18.2
16	Anticipated Production (TWh)	27	27	27	27	27	$ 136
17	Average Rate ($/MWh)	$ 135	$ 135	$ 135	$ 135	$ 135	$ 135
18	Smoothed rate ($/MWh)	$ 163	$ 157	$ 152	$ 147	$ 142	$ 152
19	Net Revenue Requirement Deferred/Recovered ($BN)	$ (0.8)	$ (0.6)	$ (0.5)	$ (0.3)	$ (0.2)	$ (2.4)
20	Interest During Period ($BN)	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 0.0	$ 0.4
21	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 2.2	$ 1.7	$ 1.3	$ 1.0	$ 0.9	N/A

Line No.		2032	2033	2034	2035	2036	2032-2036
		(a)	(b)	(c)	(d)	(e)	(f)
22	Anticipated Revenue Requirement ($BN)	$ 3.4	$ 3.4	$ 3.4	$ 3.4	$ 3.4	$ 17.1
23	Anticipated Production (TWh)	28	28	28	28	28	$ 141
24	Average Rate ($/MWh)	$ 121	$ 121	$ 121	$ 121	$ 121	$ 121
25	Smoothed rate ($/MWh)	$ 137	$ 132	$ 128	$ 123	$ 119	$ 128
26	Net Revenue Requirement Deferred/Recovered ($BN)	$ (0.4)	$ (0.3)	$ (0.2)	$ (0.1)	$ 0.1	$ (0.9)
27	Interest During Period ($BN)	$ 0.0	$ 0.0	$ 0.0	$ -	$ -	$ 0.1
28	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 0.5	$ 0.2	$ (0.0)	$ (0.1)	$ 0.0	N/A

Numbers may not add due to rounding.

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JT3.11
Attachment 1
Table 2

Table 2

Five-Year Revenue Requirement, Production, Average Rate, and Rate Smoothing Deferral Account Activity

Line No.		2017	2018	2019	2020	2021	2017-2021
		(a)	(b)	(c)	(d)	(e)	(f)
1	Anticipated Revenue Requirement ($BN)	$ 3.2	$ 3.2	$ 3.3	$ 3.8	$ 3.5	$ 17.0
2	Anticipated Production (TWh)	38	38	39	37	35	$ 188
3	Average Rate ($/MWh)	$ 84	$ 84	$ 84	$ 101	$ 99	$ 90
4	Smoothed rate ($/MWh)	$ 66	$ 73	$ 81	$ 90	$ 100	$ 82
5	Net Revenue Requirement Deferred/Recovered ($BN)	$ 0.7	$ 0.4	$ 0.1	$ 0.4	$ (0.0)	$ 1.6
6	Interest During Period ($BN)	$ 0.0	$ 0.0	$ 0.1	$ 0.1	$ 0.1	$ 0.3
7	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 0.7	$ 1.2	$ 1.4	$ 1.8	$ 1.9	N/A

Line No.		2022	2023	2024	2025	2026	2022-2026
		(e)	(e)	(e)	(e)	(e)	(f)
8	Anticipated Revenue Requirement ($BN)	$ 3.6	$ 3.4	$ 3.6	$ 3.9	$ 3.5	$ 18.1
9	Anticipated Production (TWh)	31	23	31	19	25	$ 130
10	Average Rate ($/MWh)	$ 116	$ 147	$ 117	$ 205	$ 139	$ 139
11	Smoothed rate ($/MWh)	$ 111	$ 123	$ 137	$ 152	$ 168	$ 138
12	Net Revenue Requirement Deferred/Recovered ($BN)	$ 0.2	$ 0.5	$ (0.6)	$ 1.0	$ (0.7)	$ 0.4
13	Interest During Period ($BN)	$ 0.1	$ 0.1	$ 0.1	$ 0.2	$ 0.2	$ 0.7
14	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 2.1	$ 2.8	$ 2.3	$ 3.5	$ 2.9	N/A

Line No.		2027	2028	2029	2030	2031	2027-2031
		(e)	(e)	(e)	(e)	(e)	(f)
15	Anticipated Revenue Requirement ($BN)	$ 4.2	$ 3.9	$ 3.3	$ 3.4	$ 3.5	$ 18.2
16	Anticipated Production (TWh)	24	27	28	28	27	$ 136
17	Average Rate ($/MWh)	$ 174	$ 142	$ 118	$ 118	$ 126	$ 135
18	Smoothed rate ($/MWh)	$ 163	$ 158	$ 153	$ 148	$ 143	$ 153
19	Net Revenue Requirement Deferred/Recovered ($BN)	$ 0.3	$ (0.4)	$ (1.0)	$ (0.8)	$ (0.5)	$ (2.4)
20	Interest During Period ($BN)	$ 0.2	$ 0.2	$ 0.1	$ 0.1	$ 0.1	$ 0.7
21	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 3.4	$ 3.1	$ 2.3	$ 1.5	$ 1.1	N/A

Line No.		2032	2033	2034	2035	2036	2032-2036
		(e)	(e)	(e)	(e)	(e)	(f)
22	Anticipated Revenue Requirement ($BN)	$ 3.4	$ 3.4	$ 3.5	$ 3.4	$ 3.5	$ 17.1
23	Anticipated Production (TWh)	29	28	27	28	28	$ 141
24	Average Rate ($/MWh)	$ 118	$ 119	$ 129	$ 118	$ 122	$ 121
25	Smoothed rate ($/MWh)	$ 138	$ 134	$ 130	$ 126	$ 122	$ 130
26	Net Revenue Requirement Deferred/Recovered ($BN)	$ (0.6)	$ (0.4)	$ (0.0)	$ (0.2)	$ 0.0	$ (1.2)
27	Interest During Period ($BN)	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ -	$ 0.1
28	Rate Smoothing Deferral Account Balance at End of Period ($BN)	$ 0.6	$ 0.2	$ 0.2	$ (0.0)	$ (0.0)	N/A

UNDERTAKING JT3.12

Undertaking

TO CLARIFY WHETHER THE RESPONSE TO L-11.1-1 STAFF 243 PART (D) REGARDING 63% FIXED LABOUR SHARE.

Response

The 63% fixed labour share of total O&M on LEI's TFP report comes from the EUCG dataset, which contains information on about 350 hydro plants. It was coincidental that OPG also had a similar labour share of O&M.

UNDERTAKING JT3.13

Undertaking

TO BREAK OUT EXHIBIT F4, TAB 2, SCHEDULE 1, TABLE 3 BETWEEN PRESCRIBED NUCLEAR AND PRESCRIBED HYDROELECTRIC FACILITIES

Response

Regulatory income taxes for the historical and bridge periods are calculated as described at Ex. F4-2-1, p. 2, lines 13-18:

> *As in EB-2013-0321, regulatory income taxes for the historical and bridge periods continue to be determined by applying statutory tax rates to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities, less SR&ED ITCs. Total regulatory income taxes are then allocated based on each business' regulatory taxable income, while SR&ED ITCs are predominantly directly attributed to each business unit based on the underlying expenditures giving rise to the ITCs.*

As this undertaking arose in the context of OEB Staff's questions on interrogatories related to historical years, in line with the above, Attachment 1 provides a break out of regulatory taxable income between prescribed nuclear and prescribed hydroelectric businesses for each of the years 2013-2016 that was used to allocate total regulatory income taxes (before SR&ED ITCs) calculated at Ex. F4-2-1 Table 3a, lines 25 and 26. This allocation is proportionate, unless there is negative taxable income for one of the two businesses in a given year. In that situation, consistent with the evidence in EB-2013-0321 Ex. F4-2-1, p. 3, lines 11-16, the negative taxable income of one of the regulated businesses reduces or eliminates the tax expense of the other regulated business.[1]

SR&ED ITCs continue to be reported as a component of regulatory income tax expense for each of the regulated businesses based on underlying qualifying expenditures that gave rise to the ITCs, irrespective of each business' regulatory taxable income. As explained in Ex. L-6.10-1 Staff-187, these SR&ED ITC amounts represent each regulated business' portion of the total SR&ED ITCs utilized to reduce OPG's overall corporate income taxes payable for the year (subject to a 75 percent recognition percentage for taxation years subject to audit).

Chart 1 below shows the components of regulatory income taxes for the two regulated businesses for each of the years 2013-2016. The combined regulatory income tax expense for the prescribed facilities in Chart 1 is as calculated at Ex. F4-2-1 Table 3a, line 28. Each year's total regulatory income taxes for the nuclear business is as shown in Ex. F4-2-1 Table 2, line 1.

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[1] Any remaining negative taxable income (i.e. a regulatory tax loss) is reported as negative income tax expense for the year, as illustrated for the 2013 year. The OEB applied the 2013 regulatory tax loss as a carry forward to reduce the 2014 regulatory income tax expense, as reflected in the EB-2013-0321 Payment Amounts Order, Appendix A, Table 7, line 22 and Table 7a, footnote 5.

Chart 1

$M	Nuclear Facilities	Hydroelectric Facilities	Total
	2013		
Income Taxes before SR&ED ITC	(52.9)	-	(52.9)
SR&ED ITC	(23.5)	(0.1)	(23.6)
Total Regulatory Income Taxes	(76.4)	(0.1)	(76.5)
	2014		
	Nuclear Facilities	**Hydroelectric Facilities**	**Total**
Income Taxes before SR&ED ITC	-	5.7	5.7
SR&ED ITC	(61.5)	(0.2)	(61.7)
Total Regulatory Income Taxes	(61.5)	5.5	(56.0)
	2015		
	Nuclear Facilities	**Hydroelectric Facilities**	**Total**
Income Taxes before SR&ED ITC	-	41.8	41.8
SR&ED ITC	(31.8)	(0.1)	(31.9)
Total Regulatory Income Taxes	(31.8)	41.7	9.9
	2016		
	Nuclear Facilities	**Hydroelectric Facilities**	**Total**
Income Taxes before SR&ED ITC	-	27.5	27.5
SR&ED ITC	(18.7)	(0.1)	(18.8)
Total Regulatory Income Taxes	(18.7)	27.4	8.7

Numbers may not add due to rounding.

Table 1
Calculation of Regulatory Taxable Income for Prescribed Nuclear and Prescribed Hydroelectric Facilities ($M)
Year Ending December 31, 2013

Line No.	Particulars	Nuclear Facilities	Hydroelectric Facilities	Total Regulated
		(a)	(b)	(c)
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**	(334.1)	277.4	(56.7)
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	251.3	67.8	319.1
3	**Nuclear Waste Management Expenses**	25.1	0.0	25.1
4	**Receipts from Nuclear Segregated Funds**	44.7	0.0	44.7
5	**Pension and OPEB Accrual**	290.8	14.5	305.3
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	62.9	0.0	62.9
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	(18.2)	(0.5)	(18.7)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	76.8	0.0	76.8
9	**Disallowance of Niagara Tunnel Project Expenditures**	0.0	0.0	0.0
10	**Taxable SR&ED Investment Tax Credits**	28.3	0.1	28.4
11	**Other**	19.5	0.7	20.2
12	**Total Additions**	781.2	82.7	863.8
	Deductions for Regulatory Tax Purposes:			
13	**CCA**	160.1	147.6	307.7
14	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	104.7	0.0	104.7
15	**Contributions to Nuclear Segregated Funds**	98.1	0.0	98.1
16	**Pension Plan Contributions**	231.6	11.4	242.9
17	**OPEB/SPP Payments**	78.1	3.8	81.9
18	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**	2.7	48.2	50.9
19	**Deductible SR&ED Qualifying Expenditures**	130.7	0.2	130.9
20	**Other**	0.0	1.6	1.6
21	**Total Deductions**	805.9	212.8	1,018.7
22	**Regulatory Taxable Income / (Loss)**	(358.9)	147.3	(211.6)

Table 2
Calculation of Regulatory Taxable Income for Prescribed Nuclear and Prescribed Hydroelectric Facilities ($M)
Year Ending December 31, 2014

Line No.	Particulars	Nuclear Facilities	Hydroelectric Facilities	Total Regulated
		(a)	(b)	(c)
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**	(103.5)	375.1	271.6
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	267.9	127.9	395.8
3	**Nuclear Waste Management Expenses**	31.3	0.0	31.3
4	**Receipts from Nuclear Segregated Funds**	42.3	0.0	42.3
5	**Pension and OPEB Accrual**	316.4	68.5	384.8
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	41.9	0.0	41.9
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	(12.1)	(0.3)	(12.4)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	75.2	0.0	75.2
9	**Disallowance of Niagara Tunnel Project Expenditures**	0.0	77.2	77.2
10	**Taxable SR&ED Investment Tax Credits**	19.3	(0.1)	19.2
11	**Other**	36.8	2.6	39.4
12	**Total Additions**	818.9	275.8	1,094.7
	Deductions for Regulatory Tax Purposes:			
13	**CCA**	178.2	226.1	404.3
14	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	109.1	0.0	109.1
15	**Contributions to Nuclear Segregated Funds**	170.1	0.0	170.1
16	**Pension Plan Contributions**	280.9	41.6	322.5
17	**OPEB/SPP Payments**	84.5	12.5	97.0
18	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**	4.1	50.9	55.0
19	**Deductible SR&ED Qualifying Expenditures**	174.2	0.6	174.8
20	**Other**	1.2	9.8	11.0
21	**Total Deductions**	1,002.1	341.5	1,343.7
22	**Regulatory Taxable Income / (Loss)**	(286.7)	309.4	22.7

Table 3
Calculation of Regulatory Taxable Income for Prescribed Nuclear and Prescribed Hydroelectric Facilities ($M)
Year Ending December 31, 2015

Line No.	Particulars	Nuclear Facilities	Hydroelectric Facilities	Total Regulated
		(a)	(b)	(c)
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**	(238.7)	400.9	162.2
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	296.4	141.2	437.6
3	**Nuclear Waste Management Expenses**	57.7	0.0	57.7
4	**Receipts from Nuclear Segregated Funds**	41.1	0.0	41.1
5	**Pension and OPEB Accrual**	377.5	62.1	439.6
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	49.5	0.0	49.5
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	(4.4)	(0.1)	(4.5)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	70.3	0.0	70.3
9	**Disallowance of Niagara Tunnel Project Expenditures**	0.0	2.1	2.1
10	**Taxable SR&ED Investment Tax Credits**	62.2	0.1	62.3
11	**Other**	58.7	2.4	61.1
12	**Total Additions**	1,009.0	207.8	1,216.8
	Deductions for Regulatory Tax Purposes:			
13	**CCA**	210.1	215.5	425.7
14	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	126.3	0.0	126.3
15	**Contributions to Nuclear Segregated Funds**	172.8	0.0	172.8
16	**Pension Plan Contributions**	284.5	46.8	331.3
17	**OPEB/SPP Payments**	93.1	15.2	108.3
18	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**	0.1	0.3	0.4
19	**Deductible SR&ED Qualifying Expenditures**	40.3	0.0	40.3
20	**Other**	5.4	1.3	6.7
21	**Total Deductions**	932.6	279.1	1,211.7
22	**Regulatory Taxable Income / (Loss)**	(162.2)	329.5	167.3

Table 4
Calculation of Regulatory Taxable Income for Prescribed Nuclear and Prescribed Hydroelectric Facilities ($M)
Year Ending December 31, 2016

Line No.	Particulars	Nuclear Facilities	Hydroelectric Facilities	Total Regulated
		(a)	(b)	(c)
	Determination of Regulatory Taxable Income			
1	**Regulatory Earnings Before Tax**	(218.0)	380.2	162.2
	Additions for Regulatory Tax Purposes:			
2	**Depreciation and Amortization**	319.2	139.1	458.3
3	**Nuclear Waste Management Expenses**	60.0	0.0	60.0
4	**Receipts from Nuclear Segregated Funds**	66.1	0.0	66.1
5	**Pension and OPEB Accrual**	379.9	58.0	437.9
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**	165.3	0.0	165.3
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**	(8.8)	(0.1)	(8.9)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**	65.8	0.0	65.8
9	**Disallowance of Niagara Tunnel Project Expenditures**	0.0	(21.6)	(21.6)
10	**Taxable SR&ED Investment Tax Credits**	18.6	0.1	18.7
11	**Other**	60.2	1.6	61.8
12	**Total Additions**	1,126.2	177.1	1,303.3
	Deductions for Regulatory Tax Purposes:			
13	**CCA**	300.8	213.0	513.8
14	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	162.2	0.0	162.2
15	**Contributions to Nuclear Segregated Funds**	176.7	0.0	176.7
16	**Pension Plan Contributions**	283.3	43.3	326.6
17	**OPEB/SPP Payments**	96.6	14.7	111.3
18	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**	9.6	2.4	12.0
19	**Deductible SR&ED Qualifying Expenditures**	27.7	0.8	28.5
20	**Other**	0.0	24.2	24.2
21	**Total Deductions**	1,056.9	298.4	1,355.3
22	**Regulatory Taxable Income / (Loss)**	(148.7)	258.9	110.2

UNDERTAKING JT3.14

Undertaking

WITH REFERENCE TO ISSUE 9.2, STAFF 213, AT PAGE 12 OF THE COMPENDIUM, TO GO THROUGH EACH ONE OF THE ACCOUNTS AND GIVE AN OPINION AS TO WHICH ONES IT APPLIES AND WHICH ONE IT DOESN'T

Response

This undertaking asks for OPG to comment, if the OEB determined that it was appropriate to escalate the reference amounts for some of the hydroelectric deferral and variance accounts, which accounts it would be appropriate to apply this treatment to. As discussed in response to Ex. L-9.2-1-Staff-213, OPG proposes that it is not appropriate to escalate the reference amount for any of the hydroelectric deferral and variance accounts.

In Ex. L-9.2-1-Staff-213 OPG was asked specifically about the reference amounts used to determine post-2015 hydroelectric additions to the Ancillary Services Net Revenue Account, Income and Other Taxes Variance Account, the Pension and OPEB Cash Payment Variance Account, and the Capacity Refurbishment Variance Account. OPG's position is that because Incentive Regulation decouples revenues from costs and revenue offsets, it would not be appropriate to escalate the reference amounts in these accounts by the price cap index as doing so would maintain the link between costs and revenues.

UNDERTAKING JT3.15

Undertaking

TO PROVIDE BY-YEAR SHOWING OF HOW MUCH OF DRP-RELATED ITEMS ARE IN RATE BASE AND WHAT THE MATH ON RETURN ON RATE BASE WOULD BE IN THE COST OF CAPITAL OF THIS SENSITIVITY OF 1 PERCENT OR WHATEVER WAS DONE TO THE END OF THE TEST PERIOD.

Response

This undertaking has asked for a calculation, similar to the one provided in Ex L-9.8-1-Staff-216, showing a sensitivity analysis of a 1% change to the deemed ROE as applied to the DRP in service amounts included in OPG's 2017-2021 rate base. This calculation is provided for each year from 2017-2021 in Attachment 1, Table 1.

Numbers may not add due to rounding.

Table 1

DRP Sensitivity Analysis of ROE Change

Line No.			As Filed (2017)	As Filed (2017) +1%	As Filed (2017) -1%	Reference
1	**Darlington Rate Base- DRP In-Serivce Amounts**	(a)	852.3	852.3	852.3	*Ex. B3-1-1 Table 1, line 9*
2	**ROE %**	(b)	9.19%	10.19%	8.19%	*EX.C1-1-1, Table 5*
3	**Common Equity (at 49%)** (c) = (a) x 0.49 X (b)	(c)	38.4	42.6	34.2	*EX.C1-1-1, Table 5*
4	**Grossed Up Tax Impacts (at 25%)** (d) = [(c) x 0.25] / [1-0.25]	(d)	12.8	14.2	11.4	
5	**Total Revenue Requirement** (e) = (d) + (c)	(e)	51.2	56.7	45.6	
6	**Variance from As Filed**	(f)	-	5.6	(5.6)	

Line No.			As Filed (2018)	As Filed (2018) +1%	As Filed (2018) -1%	Reference
7	**Darlington Rate Base- DRP In-Serivce Amounts**	(a)	955.2	955.2	955.2	*Ex. B3-1-1 Table 1, line 9*
8	**ROE %**	(b)	9.19%	10.19%	8.19%	*EX.C1-1-1, Table 4*
9	**Common Equity (at 49%)** (c) = (a) x 0.49 X (b)	(c)	43.0	47.7	38.3	*EX.C1-1-1, Table 4*
10	**Grossed Up Tax Impacts (at 25%)** (d) = [(c) x 0.25] / [1-0.25]	(d)	14.3	15.9	12.8	
11	**Total Revenue Requirement** (e) = (d) + (c)	(e)	57.4	63.6	51.1	
12	**Variance from As Filed**	(f)	-	6.2	(6.2)	

Line No.			As Filed (2019)	As Filed (2019) +1%	As Filed (2019) -1%	Reference
13	**Darlington Rate Base- DRP In-Serivce Amounts**	(a)	929.7	929.7	929.7	*Ex. B3-1-1 Table 1, line 16*
14	**ROE %**	(b)	9.19%	10.19%	8.19%	*EX.C1-1-1, Table 3*
15	**Common Equity (at 49%)** (c) = (a) x 0.49 X (b)	(c)	41.9	46.4	37.3	*EX.C1-1-1, Table 3*
16	**Grossed Up Tax Impacts (at 25%)** (d) = [(c) x 0.25] / [1-0.25]	(d)	14.0	15.5	12.4	
17	**Total Revenue Requirement** (e) = (d) + (c)	(e)	55.8	61.9	49.7	
18	**Variance from As Filed**	(f)	-	6.1	(6.1)	

Line No.			As Filed (2020)	As Filed (2020) +1%	As Filed (2020) -1%	Reference
19	**Darlington Rate Base- DRP In-Serivce Amounts**	(a)	5,031.4	5,031.4	5,031.4	*Ex. B3-1-1 Table 1, line 16*
20	**ROE %**	(b)	9.19%	10.19%	8.19%	*EX.C1-1-1, Table 2*
21	**Common Equity (at 49%)** (c) = (a) x 0.49 X (b)	(c)	226.6	251.2	201.9	*EX.C1-1-1, Table 2*
22	**Grossed Up Tax Impacts (at 25%)** (d) = [(c) x 0.25] / [1-0.25]	(d)	75.5	83.7	67.3	
23	**Total Revenue Requirement** (e) = (d) + (c)	(e)	302.1	335.0	269.2	
24	**Variance from As Filed**	(f)	-	32.9	(32.9)	

Line No.			As Filed (2021)	As Filed (2021) +1%	As Filed (2021) -1%	Reference
25	**Darlington Rate Base- DRP In-Serivce Amounts**	(a)	5,476.2	5,476.2	5,476.2	*Ex. B3-1-1 Table 1, line 16*
26	**ROE %**	(b)	9.19%	10.19%	8.19%	*EX.C1-1-1, Table 1*
27	**Common Equity (at 49%)** (c) = (a) x 0.49 X (b)	(c)	246.6	273.4	219.8	*EX.C1-1-1, Table 1*
28	**Grossed Up Tax Impacts (at 25%)** (d) = [(c) x 0.25] / [1-0.25]	(d)	82.2	91.1	73.3	
29	**Total Revenue Requirement** (e) = (d) + (c)	(e)	328.8	364.6	293.0	
30	**Variance from As Filed**	(f)	-	35.8	(35.8)	

UNDERTAKING JT3.16

Undertaking

IN RESPECT OF Ex. L-11.1-1 STAFF 247, TO PROVIDE PREVIOUSLY EXCLUDED DATA WITH RESPECT TO THE PRODUCTIVITY TREND OF OPG'S MANAGEMENT OF HYDROELECTRIC ASSETS

Response

OPG undertook to provide information as agreed in follow-up discussions with Mr. Ted Antonopoulos of OEB Staff, as referenced in the November 16, 2016 Technical Conference transcript at p. 92 lines 12-16. In addition, OPG has undertaken to either add nameplate values to Chart 6 of Ex. L-11.1-1 Staff-247 (Staff 247) or to provide the ratio of the maximum continuous rating to the nameplate capacity, if possible, as referenced in the November 16, 2016 Technical Conference transcript at p. 93 lines 6-8.

As agreed through the follow-up discussion with OEB Staff and in response to this undertaking, OPG provides the following supplemental information in connection with Staff 247:

1. An expanded version of Chart 1, including estimated data from OPG's inception in April 1999, filed as Chart 1A, below.

2. An expanded version of Chart 2, including estimated data from April 1999, filed as Chart 2A, below.

   OPG has adjusted the group of hydroelectric assets included in Charts 1A and 2A, in order to be consistent with Charts 3, 5, and 6. As described in parts (a), (b) and (e) of Staff 247, Charts 1 and 2 provided information on OPG's <u>currently regulated hydroelectric assets</u> over the 2002-2015 period. Charts 3, 5, and 6 were prepared on a different basis; they reflected all of OPG's <u>currently operating hydroelectric assets</u>, removing assets as they became subject to IESO contracts.[1]

   In order to provide a consistent set of data in this response, OPG has prepared Charts 1A and 2A on the same basis as Charts 3, 5, 5A, 6, and 6A (i.e., removing amounts for generation as it became contracted). Charts 1A and 2A include a column removing amounts for facilities that became contracted each year.

   During the Technical Conference, OEB Staff's consultant asked several questions related to the valuation of OPG's hydroelectric assets as acquired from Ontario Hydro at the time Ontario Hydro ended operations.[2] OPG notes that the valuation of OPG's assets was discussed in greater detail during the previous payment amounts

[1] The basis on which Charts 3, 5 and 6 were prepared is described in the response to parts d) and i) of Staff 247.
[2] EB-2016-0152, Technical Conference Transcript: November 16, 2016, pages 87-90.

application, EB-2013-0321, and refers OEB Staff to the transcript of that proceeding[3] and a related undertaking[4] for further background information.

3. An expanded version of Chart 5, including data from 1989, filed as Chart 5A, below.

4. An expanded version of Chart 6, including data from 1989, filed as Chart 6A, below. Chart 6A also includes the original nameplate capacity of OPG's hydroelectric generating stations, consistent with the other charts provided in this undertaking. As noted in OPG's response to part (i) of Staff 247, the nameplate capacity does not accurately reflect the capacity of the facilities. The nameplate capacity does not account for upgrades and other work that has affected stations' capacity since they were first put into service. The Maximum Continuous Rating values provided in Chart 5 represent the current, accurate capacity of OPG's hydroelectric assets.

5. Excerpts from the Ontario Hydro Statistical Yearbooks from 1989 to 1993, included as Attachment 1.

6. Excerpts from the Ontario Hydro Annual Reports from 1989 to 1996, included as Attachment 2.

While OPG does not know which specific data OEB Staff plans to use from the Ontario Hydro Statistical Yearbooks and Annual Reports, it cautions that there are significant discontinuities between the data in those documents and OPG's own data as reported to the OEB in the current and in prior proceedings, beyond the asset valuation issue noted above. OPG identifies the following non-exhaustive list of discontinuities that may arise if OEB Staff were to rely on data from the Ontario Hydro documents:

1. The hydroelectric capacities in the Statistical Yearbooks are measured as "dependable peak capacities," based on estimated stream flows (98% confidence level). These capacities can vary year over year depending on hydrological conditions and are not necessarily indicative of the physical capability of the equipment.

2. The overall capacities reported in the Statistical Yearbooks are subject to two major, unusual adjustments: (i) a negative adjustment at Niagara and, (ii) an overall positive adjustment for "diversity of total system". OPG's data in Chart 6A does not reflect such adjustments.

3. There are several plants in the Statistical Yearbook tables that have been either decommissioned or sold. For example, Ontario Power GS and Toronto Power GS have been decommissioned, and Aubrey Falls, GW Rayner, Wells and Red Rock Falls stations were sold in 2002.

[3] EB-2013-0321, Hearing Transcript: July 14, 2014, pages 130-138.
[4] EB-2013-0321, Undertaking J12.3.

4. The dependable peak capacity of Sir Adam Beck 1 is based on 10 units. Units 1 and 2 (25 cycle) are presently shutdown and their capacity is not included in the data set provided by OPG in the accompanying charts. The dependable peak capacity for DeCew Falls No.1 is based on 5 units (one unit was permanently shutdown, and the station now has 4 units).

Chart 1A
Continuity of Gross Hydroelectric Property, Plant and Equipment ($M)

Line No.	Year	Opening Balance	In-Service Additions	Retirements, Transfers & Adjustments	Removal of Asset Upon Becoming Contracted	Closing Balance
		(a)	(b)	(c)	(d)	(e)
1	1999[1]	7,216.5	49.9	-	-	7,266.4
2	2000	7,266.4	66.0	0.4	-	7,332.9
3	2001	7,332.9	60.5	0.5	-	7,393.9
4	2002	7,393.9	91.6	8.9	-	7,494.4
5	2003	7,494.4	39.3	23.6	-	7,557.4
6	2004	7,557.4	120.2	5.7	-	7,683.2
7	2005	7,683.2	58.0	28.1	-	7,769.3
8	2006	7,769.3	55.4	2.1	-	7,826.8
9	2007	7,826.8	83.5	(8.7)	-	7,901.6
10	2008	7,901.6	57.4	(14.6)	-	7,944.5
11	2009	7,944.5	97.1	(19.1)	(23.4)	7,999.0
12	2010	7,999.0	136.9	(12.6)	(43.7)	8,079.6
13	2011	8,079.6	134.6	(8.5)	(501.8)	7,704.0
14	2012	7,704.0	59.9	(13.7)	-	7,750.2
15	2013	7,750.2	1,559.1	(9.0)	-	9,300.3
16	2014	9,300.3	74.3	(85.6)	-	9,288.9
17	2015	9,288.9	71.2	(6.9)	-	9,353.2

[1] As estimated for the period from OPG's inception in April 1, 1999 to December 31, 1999. Subsequent material true-up adjustments to the April 1, 1999 asset valuation are reflected as of April 1, 1999 for continuity purposes.

Chart 2A
Continuity of Hydroelectric Accumulated Depreciation and Amortization ($M)

Line No.	Year	Opening Balance	Depreciation and Amortization	Retirements, Transfers & Adjustments	Removal of Asset Upon Becoming Contracted	Closing Balance
		(a)	(b)	(c)	(d)	(e)
1	1999	-	(91.5)	-	-	(91.5)
2	2000	(91.5)	(119.6)	(0.3)	-	(211.4)
3	2001	(211.4)	(113.6)	(0.3)	-	(325.4)
4	2002	(325.4)	(115.4)	(2.8)	-	(443.5)
5	2003	(443.5)	(117.2)	(2.6)	-	(563.4)
6	2004	(563.4)	(120.0)	(0.1)	-	(683.5)
7	2005	(683.5)	(121.0)	(8.2)	-	(812.6)
8	2006	(812.6)	(121.1)	(3.0)	-	(936.8)
9	2007	(936.8)	(123.6)	3.4	-	(1,057.0)
10	2008	(1,057.0)	(125.0)	5.4	-	(1,176.5)
11	2009	(1,176.5)	(124.5)	8.0	4.4	(1,288.6)
12	2010	(1,288.6)	(126.1)	8.6	2.1	(1,404.1)
13	2011	(1,404.1)	(120.0)	3.1	92.5	(1,428.6)
14	2012	(1,428.6)	(121.3)	6.0	-	(1,544.0)
15	2013	(1,544.0)	(137.1)	4.9	-	(1,676.3)
16	2014*	(1,676.3)	(138.4)	8.9	-	(1,805.8)
17	2015	(1,805.8)	(138.2)	3.7	-	(1,940.4)

* Amount in col. (c) includes an adjustment to reduce the Niagara Tunnel Project in-service amount to the approve value per EB-2013-0321 Payment Amounts Order, App. A, Table 1a, Note 2.

Chart 5A
Total Hydroelectric Generation (TWh)

Years	Generation	Generation with PGS
1989	34.3	34.2
1990	35.6	35.5
1991	33.2	33.1
1992	35.3	35.2
1993	35.7	35.5
1994	34.7	34.5
1995	34.4	34.2
1996	36.3	36.2
1997	35.2	35.1
1998	31.2	31.1
1999	33.1	33.0
2000	34.1	33.9
2001	33.1	32.9
2002	33.9	33.8
2003	33.1	33.0
2004	35.3	35.2
2005	33.4	33.2
2006	34.2	34.0
2007	32.9	32.7
2008	37.4	37.3
2009	36.3	36.2
2010	30.5	30.4
2011	31.3	31.2
2012	29.5	29.4
2013	31.4	31.3
2014	31.5	31.4
2015	30.3	30.2

Chart 6A

Maximum Continuous Rating and Original Name Plate Capacity - Hydroelectric Facilities (MW)

Years	Generation Capacity / MCR	Original Name Plate Capacity
1989	6523	5775
1990	6523	5775
1991	6523	5775
1992	6523	5775
1993	6523	5775
1994	6546	5781
1995	6563	5783
1996	6642	5838
1997	6666	5838
1998	6718	5838
1999	6763	5838
2000	6813	5838
2001	6866	5838
2002	6899	5838
2003	6926	5838
2004	6958	5838
2005	6924	5787
2006	6971	5787
2007	6971	5787
2008	7015	5838
2009	6915	5725
2010	6906	5713
2011	6422	5284
2012	6422	5284
2013	6433	5284
2014	6433	5284
2015	6428	5284

Ontario Hydro Statistical Yearbook

Supplement to the Eighty-second Annual Report

THE CORPORATION

Ontario Hydro's prime objective is to supply the people of Ontario with electricity at cost while maintaining high standards of safety and service. To that end, it operates 80 hydro-electric, fossil-fuelled and nuclear generating stations and an extensive power grid across Ontario to meet the province's demands for electric energy.

Ontario Hydro is a financially self-sustaining corporation without share capital created in 1906 by a special statute of the Province of Ontario. Bonds and notes issued to the public by the Corporation are guaranteed by the province.

Under the authority of the Power Corporation Act, Ontario Hydro has broad powers to generate, supply and deliver electricity throughout the province. It is also authorized to produce and sell steam and hot water as primary products. In addition, Ontario Hydro exercises specific regulatory functions over municipal utilities as well as the approval and inspection functions for electrical equipment (in conjunction with the Canadian Standards Association) and electrical wiring installations throughout the province.

Ontario Hydro sells wholesale electric power to 315 municipal utilities in urban areas which, in turn, retail to customers in their service areas. Ontario Hydro also serves directly more than 100 large industrial customers and 891,319 rural retail customers in areas or communities not served by municipal utilities. In 1989, 3,573,886 customers were served by Ontario Hydro and the municipal utilities in the province.

The corporation is controlled by a Board of Directors. The board can have up to 17 members who are appointed by the Lieutenant-Governor-in-Council of Ontario. The President and Chief Executive Officer, also a Board member, is a full-time employee of the corporation and appointed by the Board.

Ontario Hydro's head office is located at 700 University Avenue, Toronto, Ontario. For administrative and operational purposes, six regional and 47 area offices are maintained throughout the province.

OPERATIONS

STATISTICAL SUMMARY 1989–1979

		1989	1988	1987	1986	1985	1984	1983	1982	1981	1980	1979
In-service dependable peak capacity, December	thousand kW	28,162	28,224	27,414	26,918	24,291	22,613	21,486	21,872	22,617	22,561	22,664
Primary peak demand, December	thousand kW	23,630	23,012	20,524	20,609	20,473	18,052	18,792	16,872	16,600	16,808	16,365
Annual energy generated and received (1)	million kW.h	143,062	139,413	132,970	126,620	124,614	122,920	117,971	111,589	112,722	110,901	109,789
Primary energy demand	million kW.h	140,770	134,395	126,455	120,574	116,049	112,293	106,071	100,836	101,659	100,174	98,127
Secondary sales	million kW.h	2,292	5,018	6,515	6,046	8,565	10,627	11,900	10,753	11,063	10,727	11,662
Annual energy sold by Ontario Hydro (2)	million kW.h	134,454	131,752	125,626	119,501	117,834	116,590	111,673	105,758	107,339	104,994	103,778
Primary revenue of Ontario Hydro	million $	6,255	5,657	5,084	4,605	4,274	3,783	3,357	2,969	2,737	2,458	2,222
Fixed assets at cost	million $	39,380	36,264	33,567	31,049	28,763	26,216	23,554	20,786	18,235	16,073	14,776
Gross expenditure on fixed assets in year	million $	3,194	2,789	2,609	2,603	2,617	2,719	2,847	3,006	2,207	1,369	1,659
Total assets, less accumulated depreciation	million $	36,277	34,358	32,657	31,357	29,320	27,301	23,194	20,721	17,830	15,593	14,514
Long-term liabilities and notes payable	million $	26,802	26,405	25,566	24,825	23,148	21,555	18,266	16,443	14,197	12,520	11,536
Transmission line (circuit length)	kilometres	27,637	27,591	27,329	27,111	27,105	27,022	27,030	26,875	26,596	26,476	39,485
Distribution line (3)	kilometres	105,880	104,771	103,703	102,740	103,003	102,128	101,769	101,562	101,211	101,601	90,157
Average number of employees in year		34,076	32,473	32,147	32,405	31,166	29,613	31,233	32,654	30,850	28,902	28,385
Number of associated municipal electrical utilities		315	316	316	316	316	319	320	324	324	324	332
Ultimate customers served by Ont. Hydro and municipal utilities	thousands	3,574	3,456	3,351	3,252	3,172	3,105	3,051	3,004	2,967	2,927	2,878

(1) Excludes circulating energy flows.
(2) Excludes transmission losses, internal primary loads (construction projects and heavy water plant).
(3) Transmission lines under 50 kV classified distribution beginning in 1980.

FUEL CONSUMED TO PRODUCE ELECTRICITY

Kind of Fuel	Consumed in Year 1989	Consumed in Year 1988	Percentage Change in 1989
Uranium (megagrams)	1,128.9	1,160.5	−2.7
Coal (megagrams)	12,809,422	13,078,283	−2.1
Ignition and Combustion Turbine Oil (cubic metres)	54,080	46,543	+16.2
Residual Oil (cubic metres)	379,510	122,018	+211.0

POWER DEVELOPMENT PROJECTS UNDER CONSTRUCTION as at December 31,1989

Development	Units: Number	Units: Type	Installation Schedule	Installed Capacity: Installed	Installed Capacity: Under Construction
				kW	kW
Darlington—Lake Ontario near Newcastle	4	TN	1990-90-91-92	—	3,600,000

TN—Thermal-electric nuclear

POWER RESOURCES AND REQUIREMENTS

The analysis on page 5 of energy made available by Ontario Hydro shows for the total system, the energy obtained from each major source in 1988 and 1989 and the related percentage changes in 1989. The table also shows the primary and secondary energy supplied in each year together with the percentage changes in 1989.

The table of In-Service Dependable Capacity and Primary Demand on page 5 shows the primary peak demand for the month of December and the in-service dependable peak capacity of resources at that time. The primary peak demand was 23,630 MW on December 13. However on December 21 the recorded peak was 23,424 MW simultaneous with a total of 975 MW of demand reduction achieved by cutting interruptible loads and by voltage reduction. This means that the underlying peak demand was 24,399 MW on that day; however, the 975 MW was unserved. A separate table on pages 6 and 7 gives the in-service dependable peak capacity of major Ontario Hydro generating stations and contract firm power purchases at the time of the December system peak. Any comparison of total primary peak demand and resources should make allowance for the part of total primary demand that may be interrupted under contracts accepted by the customer. In 1989 this interruptible load over the December peak was approximately 485 megawatts.

The in-service dependable peak capacity of a hydraulic generation station is the estimated output that an analysis of stream-flow conditions indicates the station is capable of producing 98 percent of the time. It can be expected to exceed this output in 49 out of 50 years. Since the stations so rated are distributed on many widely separated watersheds and since all would not be simultaneously affected by stream flows, the amount by which the total hydro-electric generating capacity of the system exceeds the sum of various station capacities represents the diversity in stream flow within the system.

The in-service dependable peak capacity of a thermal generating station is the net peaking capacity of its fully commissioned units minus capacity which is mothballed or frozen.

ENERGY MADE AVAILABLE BY ONTARIO HYDRO

	1989	1988	Increase or Decrease
TOTAL SYSTEM	MW.h	MW.h	%
Generation — Nuclear	65,261,436	67,552,078	(3.4)
— Fossil	35,348,894	34,708,332	1.8
— Hydraulic	35,088,109	35,087,359	0.0
Total Generation	135,698,439	137,347,769	(1.2)
Purchases and Net Other Interchange(1)	7,363,725	2,065,485	256.5
Total Resources Generated and Received	143,062,164	139,413,254	2.6
Primary Demand	140,770,186	134,394,697	4.7
Secondary Sales	2,291,978	5,018,557	(54.3)

IN-SERVICE DEPENDABLE CAPACITY AND PRIMARY DEMAND DECEMBER PEAK 1989 AND 1988

	1989	1988	Net Increase	
TOTAL SYSTEM	MW	MW	MW	%
In-Service Dependable Capacity				
Generation — Nuclear	10,594.0	10,584.0	10.0	0.1
— Fossil	11,019.5	11,091.5	(72.0)	(0.6)
— Hydraulic	6,548.4	6,548.4	0.0	0.0
Total Generation	28,161.9	28,223.9	(62.0)	(0.2)
Firm Purchases	0.0	0.0	0.0	0.0
Total Resources	28,161.9	28,223.9	(62.0)	(0.2)
Reserve or Deficiency	4,531.9	5,211.9	(680.0)	(13.0)
Primary Peak Demand	23,630.0	23,012.0	618.0	2.7
Ratio of Reserve or Deficiency to Primary Demand %	19.2	22.6		

The capacities shown are those available for a 20-minute period at the time of the System Primary Peak Demand in December, the capacity of the purchased power sources being based on the terms of the purchased contract. The Primary Peak Demand shown is the maximum peak for December. Some part of the System Primary Demand is subject to interruption in accordance with contract terms accepted by the customer. The total load subject to such interruptions at the time of the December peak is 485 MW.

ONTARIO HYDRO'S TOTAL RESOURCES—1989

Location	Nuclear Generating Stations	In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Kincardine	Bruce	6,470.0	39,758,525
Pickering	Pickering	4,124.0	25,502,911
	Total Nuclear Generation	10,594.0	65,261,436
	Fossil Generating Stations		
Atikokan	Atikokan	215.0	1,126,893
Windsor	Keith	0.0	(3,827)
Toronto	Richard L. Hearn	0.0	(24,754)
Mississauga	Lakeview	2,184.0	5,755,865
Courtright	Lambton	2,040.0	8,812,875
Kingston	Lennox	1,674.0	1,294,706
Nanticoke	Nanticoke	4,336.0	16,782,885
Thunder Bay	Thunder Bay	320.0	1,569,529
	Combustion Turbine and Diesel-Electric	250.5	34,722
	Total Fossil Generation	11,019.5	35,348,894
River	**Hydraulic Generating Stations**		
Niagara	Sir Adam Beck-Niagara No.1	448.0	2,373,879
	Sir Adam Beck-Niagara No.2	1,324.0	9,531,106
	Pumping-Generating Station	125.0	(118,526)
	Ontario Power	28.0	134,483
	Toronto Power		(541)
Welland Canal	DeCew Falls No.1	31.0	77,591
	DeCew Falls No.2	132.0	1,204,298
	Adjustment to Niagara River Stations to compensate for use of water by Ontario Hydro rather than by another producer	(75.0)	
St. Lawrence	Robert H. Saunders	707.0	6,443,742
Ottawa	Des Joachims	419.0	2,275,372
	Otto Holden	217.0	1,168,407
	Chenaux	113.0	711,244
	Chats Falls (Ontario half)	86.0	478,929
Madawaska	Mountain Chute	165.0	238,804
	Barrett Chute	172.0	240,283
	Stewartville	166.0	247,451
	Arnprior	78.0	118,577

ONTARIO HYDRO'S TOTAL RESOURCES—1989

		In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Abitibi	Abitibi Canyon	294.0	1,393,217
	Otter Rapids	177.0	750,045
Mississagi	Aubrey Falls	158.0	166,132
	George W. Rayner	46.0	27,987
	Wells	229.0	326,240
	Red Rock Falls	40.0	177,269
Mattagami	Kipling	142.0	599,342
	Little Long	125.0	528,966
	Harmon	129.0	620,957
Montreal	Lower Notch	254.0	428,436
Nipigon	Pine Portage	112.4	887,723
	Cameron Falls	75.8	630,325
	Alexander	62.4	508,854
English	Caribou Falls	80.3	533,875
	Manitou Falls	59.5	395,510
Kaministikwia	Silver Falls	45.7	252,198
Winnipeg	Whitedog Falls	59.3	439,676
Aguasabon	Aguasabon	45.0	259,042
Various	Other Hydraulic Generating Stations	169.8	1,037,216
(1)	Adjustment for Diversity-Total System	108.2	
	Total Hydraulic Generation	6,548.4	35,088,109
	Total Generation	28,161.9	135,698,439
Purchases and Other Interchange			
(4)	Purchases		
	–Ontario		241,953
	–Hydro Quebec		99,243
	–Manitoba Hydro		1,248,311
	–USA		5,742,161
	Total Purchases	0	7,331,668
(2)	Other Net Interchange (Net)		32,057
	Total Receipts	0.0	7,363,725
	Total Generated and Received	28,161.9	143,062,164

(1) Adjustment to reconcile the sum of plant capacities with the calculated capacity of the system.
(2) Net scheduled interconnection transactions of other than purchases and sales. These include electrical energy exchanges, carrier transfers, water use adjustments, generating unit rentals.
(3) Installed dependable capacity peak at the time of the December peak minus capacity which is frozen or mothballed.
(4) Dependable capacity is the firm contract commitments at the time of of the December peak.

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THE CORPORATION

ONTARIO HYDRO was created in 1906 by a special statute of the Province of Ontario. We are a financially self-sustaining corporation without share capital. Bonds and notes issued by the corporation are guaranteed by the Province.

Ontario Hydro serves the people of the province by supplying reasonably-priced and reliable electricity. We also help meet our customers' broader energy needs by providing comprehensive information about energy conservation. Ontario Hydro is developing innovative programs to better manage energy consumption, and offering financial incentives for greater energy efficiency.

Under the Power Corporation Act, it is our responsibility to generate, supply and deliver electricity throughout Ontario as well as to provide energy conservation programs. We also produce and sell steam and hot water as primary products. We work with and regulate municipal utilities. In co-operation with the Canadian Standards Association, we are responsible for the inspection and approval of electrical equipment and wiring throughout Ontario. We sell electricity to 314 municipal utilities, which then sell this power to customers in their service area. We also directly serve more than 100 large industrial customers and 918,368 small business, residential, and farm customers in rural and remote areas. In 1990, 3,654,253 customers were served by Ontario Hydro and the municipal utilities.

Ontario Hydro operates 81 hydro-electric, fossil-fuelled, and nuclear generating stations and an extensive transmission and distribution system across the province.

The Corporation is governed by a Board of Directors. The Board can have up to 17 members, 16 of whom are appointed by the Lieutenant-Governor-in-Council of Ontario. The President and Chief Executive Officer, also a Board member, is a full-time employee of Ontario Hydro and appointed by the Board.

Ontario Hydro's head office is located at 700 University Avenue, Toronto, Ontario. For administrative and operational purposes, six regional and 45 area offices are maintained throughout the province.

OPERATIONS

STATISTICAL SUMMARY 1990–1980

		1990	1989	1988	1987	1986	1985	1984	1983	1982	1981	1980
In-service dependable peak capacity, December	thousand kW	29,600	28,162	28,224	27,414	26,918	24,291	22,613	21,486	21,872	22,617	22,561
Primary peak demand, December	thousand kW	21,785	23,630	23,012	20,524	20,609	20,473	18,052	18,792	16,872	16,600	16,808
Annual energy generated and received (1)	million kW.h	137,321	143,062	139,413	132,970	126,620	124,614	122,920	117,971	111,589	112,722	110,901
Primary energy demand	million kW.h	136,744	140,770	134,395	126,455	120,574	116,049	112,293	106,071	100,836	101,659	100,174
Secondary sales	million kW.h	577	2,292	5,018	6,515	6,046	8,565	10,627	11,900	10,753	11,063	10,727
Annual energy sold by Ontario Hydro (2)	million kW.h	129,690	134,454	131,752	125,626	119,501	117,834	116,590	111,673	105,758	107,339	104,994
Primary revenue of Ontario Hydro	million $	6,462	6,255	5,657	5,084	4,605	4,274	3,783	3,357	2,969	2,737	2,458
Fixed assets at cost	million $	42,962	39,380	36,264	33,567	31,049	28,763	26,216	23,554	20,786	18,235	16,073
Gross expenditure on fixed assets in year	million $	3,653	3,194	2,789	2,609	2,603	2,617	2,719	2,847	3,006	2,207	1,369
Total assets, less accumulated depreciation	million $	39,373	36,277	34,358	32,657	31,357	29,320	27,301	23,194	20,721	17,830	15,593
Long-term liabilities and notes payable	million $	29,378	26,802	26,405	25,566	24,825	23,148	21,555	18,266	16,443	14,197	12,520
Transmission line (circuit length)	kilometres	28,117	27,637	27,591	27,329	27,111	27,105	27,022	27,030	26,875	26,596	26,476
Distribution line (3)	kilometres	106,805	105,880	104,771	103,703	102,740	103,003	102,128	101,769	101,562	101,211	101,601
Average number of employees in year		36,474	34,076	32,473	32,147	32,405	31,166	29,613	31,233	32,654	30,850	28,902
Number of associated municipal electrical utilities		314	315	316	316	316	316	319	320	324	324	324
Ultimate customers served by Ont. Hydro and municipal utilities	thousands	3,654	3,577	3,456	3,351	3,252	3,172	3,105	3,051	3,004	2,967	2,927

(1) Excludes circulating energy flows.

(2) Excludes transmission losses, internal primary loads (construction projects and heavy water plant).

(3) Transmission lines under 50 kV classified distribution beginning in 1980.

FUEL CONSUMED TO PRODUCE ELECTRICITY

Kind of Fuel	Consumed in Year 1990	Consumed in Year 1989	Percentage Change in 1990
Uranium (megagrams)	1,051.5	1,128.9	−8.9
Coal (megagrams)	10,361,572	12,809,422	−19.1
Ignition and Combustion Turbine Oil (cubic metres)	58,441	54,080	+8.1
Residual Oil (cubic metres)	319,750	379,510	−15.8

POWER DEVELOPMENT PROJECTS UNDER CONSTRUCTION as at December 31, 1990

Development	Units		Installation Schedule	Installed Capacity	
	Number	Type		Installed	Under Construction
				kW	kW
Darlington—Lake Ontario near Newcastle	4	TN	1990-91-92-93	900,000	2,700,000

TN—Thermal-electric nuclear

POWER RESOURCES AND REQUIREMENTS

The analysis on page 5 of energy made available by Ontario Hydro shows for the total system, the energy obtained from each major source in 1989 and 1990 and the related percentage changes in 1990. The table also shows the primary and secondary energy supplied in each year together with the percentage changes in 1990.

The table of In-Service Dependable Capacity and Primary Demand on page 5 shows the primary peak demand for the month of December and the in-service dependable peak capacity of resources at that time. A separate table on pages 6 and 7 gives the in-service dependable peak capacity of major Ontario Hydro generating stations and contract firm power purchases at the time of the December system peak. Any comparison of total primary peak demand and resources should make allowance for the part of total primary demand that may be interrupted under contracts accepted by the customer. In 1990 this interruptible load over the December peak was approximately 329 megawatts.

The in-service dependable peak capacity of a hydraulic generation station is the estimated output that an analysis of stream-flow conditions indicates the station is capable of producing 98 percent of the time. It can be expected to exceed this output in 49 out of 50 years. Since the stations so rated are distributed on many widely separated watersheds and since all would not be simultaneously affected by stream flows, the amount by which the total hydro-electric generating capacity of the system exceeds the sum of various station capacities represents the diversity in stream flow within the system.

The in-service dependable peak capacity of a thermal generating station is the net peaking capacity of its fully commissioned units minus capacity which is mothballed or frozen.

ENERGY MADE AVAILABLE BY ONTARIO HYDRO

	1990	1989	Increase or Decrease
TOTAL SYSTEM	MW.h	MW.h	%
Generation — Nuclear	59,468,855	65,261,436	(8.9)
— Fossil	27,458,229	35,348,894	(22.3)
— Hydraulic	36,630,783	35,088,109	4.4
Total Generation	123,557,867	135,698,439	(8.9)
Purchases and Net Other Interchange(1)	13,763,555	7,363,725	86.9
Total Resources Generated and Received	137,321,422	143,062,164	(4.0)
Primary Demand	136,744,134	140,770,186	(2.9)
Secondary Sales	577,288	2,291,978	(74.8)

IN-SERVICE DEPENDABLE CAPACITY AND PRIMARY DEMAND DECEMBER PEAK 1990 AND 1989

	1990	1989	Net Increase	
TOTAL SYSTEM	MW	MW	MW	%
In-Service Dependable Capacity				
Generation — Nuclear	11,475.0	10,594.0	881.0	8.3
— Fossil	11,577.5	11,019.5	558.0	5.1
— Hydraulic	6,547.0	6,548.4	(1.4)	(0.0)
Total Generation	29,599.5	28,161.9	1,437.6	5.1
Firm Purchases	0.0	0.0	0.0	0.0
Total Resources	29,599.5	28,161.9	1,437.6	5.1
Reserve or Deficiency	7,814.5	4,531.9	3,282.6	72.4
Primary Peak Demand	21,785.0	23,630.0	(1,845.0)	(7.8)
Ratio of Reserve or Deficiency to Primary Demand %	35.9	19.2		

The capacities shown are those available for a 20-minute period at the time of the System Primary Peak Demand in December, the capacity of the purchased power sources being based on the terms of the purchased contract. The Primary Peak Demand shown is the maximum peak for December. Some part of the System Primary Demand is subject to interruption in accordance with contract terms accepted by the customer. The total load subject to such interruptions at the time of the December peak is 329 MW.

ONTARIO HYDRO'S TOTAL RESOURCES—1990

Location	Nuclear Generating Stations	In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Kincardine	Bruce	6,470.0	35,708,249
Pickering	Pickering	4,124.0	20,800,148
Bowmanville	Darlington	881.0	2,960,458
	Total Nuclear Generation	11,475.0	59,468,855
	Fossil Generating Stations		
Atikokan	Atikokan	215.0	1,067,888
Windsor	Keith	0.0	(7,006)
Toronto	Richard L. Hearn	0.0	(22,392)
Mississauga	Lakeview	2,184.0	3,704,745
Courtright	Lambton	2,040.0	5,677,330
Kingston	Lennox	2,232.0	1,087,146
Nanticoke	Nanticoke	4,336.0	14,415,087
Thunder Bay	Thunder Bay	320.0	1,516,237
	Combustion Turbine and Diesel-Electric	250.5	19,194
	Total Fossil Generation	11,577.5	27,458,229
River	**Hydraulic Generating Stations**		
Niagara	Sir Adam Beck-Niagara No.1	448.0	2,363,946
	Sir Adam Beck-Niagara No.2	1,324.0	9,651,788
	Pumping-Generating Station	125.0	(106,397)
	Ontario Power	28.0	221,665
	Toronto Power		(1.025)
Welland Canal	DeCew Falls No.1	31.0	79,287
	DeCew Falls No.2	132.0	1,088,577
	Adjustment to Niagara River Stations to compensate for use of water by Ontario Hydro rather than by another producer	(75.0)	
St. Lawrence	Robert H. Saunders	707.0	6,877,291
Ottawa	Des Joachims	419.0	2,496,619
	Otto Holden	217.0	1,280,320
	Chenaux	113.0	780,068
	Chats Falls (Ontario half)	86.0	553,068
Madawaska	Mountain Chute	165.0	282,315
	Barrett Chute	172.0	287,737
	Stewartville	166.0	294,624
	Arnprior	78.0	142,713

ONTARIO HYDRO'S TOTAL RESOURCES—1990

		In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Abitibi	Abitibi Canyon	294.0	1,531,848
	Otter Rapids	177.0	864,788
Mississagi	Aubrey Falls	158.0	183,320
	George W. Rayner	46.0	38,240
	Wells	229.0	377,283
	Red Rock Falls	40.0	203,928
Mattagami	Kipling	142.0	859,367
	Little Long	125.0	693,447
	Harmon	129.0	808,856
Montreal	Lower Notch	254.0	477,762
Nipigon	Pine Portage	112.4	693,307
	Cameron Falls	75.8	479,667
	Alexander	62.4	382,335
English	Caribou Falls	80.3	500,346
	Manitou Falls	59.5	383,276
Kaministikwia	Silver Falls	45.7	231,779
Winnipeg	Whitedog Falls	59.3	323,358
Aguasabon	Aguasabon	45.0	275,137
Various	Other Hydraulic Generating Stations	170.4	1,030,143
(1)	Adjustment for Diversity-Total System	106.2	
	Total Hydraulic Generation	6,547.0	36,630,783
	Total Generation	29,599.5	123,557,867
Purchases and Other Interchange			
(4)	Purchases		
	–Ontario		570,431
	–Hydro Quebec		12,318
	–Manitoba Hydro		1,619,599
	–USA		11,415,681
	Total Purchases	0	13,618,029
(2)	Other Net Interchange (Net)		145,526
	Total Receipts	0.0	13,763,555
	Total Generated and Received	29,599.5	137,321,422

(1) Adjustment to reconcile the sum of plant capacities with the calculated capacity of the system.
(2) Net scheduled interconnection transactions of other than purchases and sales. These include electrical energy exchanges, carrier transfers, water use adjustments, generating unit rentals.
(3) Installed dependable capacity peak at the time of the December peak minus capacity which is frozen or mothballed.
(4) Dependable capacity is the firm contract commitments at the time of of the December peak.

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THE CORPORATION

ONTARIO HYDRO was created in 1906 by a special statute of the Province of Ontario. We are a financially self-sustaining corporation without share capital. Bonds and notes issued by the corporation are guaranteed by the Province.

Ontario Hydro serves the people of the province by supplying reasonably-priced and reliable electricity. We also help meet our customers' broader energy needs by providing comprehensive information about energy conservation. Ontario Hydro develops innovative programs to better manage energy consumption, and offers financial incentives for greater energy efficiency.

Under the Power Corporation Act, it is our responsibility to generate, supply and deliver electricity throughout Ontario as well as to provide energy conservation programs. We also produce and sell steam and hot water as primary products. We work with and regulate municipal utilities. In co-operation with the Canadian Standards Association, we are responsible for the inspection and approval of electrical equipment and wiring throughout Ontario. We sell electricity to 311 municipal utilities, which then sell this power to customers in their service area. We also directly serve more than 100 large industrial customers and 925,641 small business, residential, and farm customers in rural and remote areas. In 1991, 3,695,998 customers were served by Ontario Hydro and the municipal utilities.

Ontario Hydro operates 81 hydro-electric, fossil-fuelled, and nuclear generating stations and an extensive transmission and distribution system across the province.

The Corporation is governed by a Board of Directors. The Board can have up to 17 members, 16 of whom are appointed by the Lieutenant-Governor-in-Council of Ontario. The President and Chief Executive Officer, also a Board member, is a full-time employee of Ontario Hydro and appointed by the Board.

Ontario Hydro's head office is located at 700 University Avenue, Toronto, Ontario. For administrative and operational purposes, six regional and 45 area offices are maintained throughout the province.

OPERATIONS

STATISTICAL SUMMARY 1991–1981

		1991	1990	1989	1988	1987	1986	1985	1984	1983	1982	1981
In-service dependable peak capacity, December	thousand kW	30,588	29,600	28,162	28,224	27,414	26,918	24,291	22,613	21,486	21,872	22,617
Primary peak demand, December	thousand kW	22,933	21,785	23,630	23,012	20,524	20,609	20,473	18,052	18,792	16,872	16,600
Annual energy generated and received (1)	million kW.h	139,088	137,321	143,062	139,413	132,970	126,620	124,614	122,920	117,971	111,589	112,722
Primary energy demand	million kW.h	136,966	136,744	140,770	134,395	126,455	120,574	116,049	112,293	106,071	100,836	101,659
Secondary sales	million kW.h	2,123	577	2,292	5,018	6,515	6,046	8,565	10,627	11,900	10,753	11,063
Annual energy sold by Ontario Hydro (2)	million kW.h	131,840	129,690	134,454	131,752	125,626	119,501	117,834	116,590	111,673	105,758	107,339
Primary revenue of Ontario Hydro	million $	7,081	6,462	6,255	5,657	5,084	4,605	4,274	3,783	3,357	2,969	2,737
Fixed assets at cost	million $	46,914	42,962	39,380	36,264	33,567	31,049	28,763	26,216	23,554	20,786	18,235
Gross expenditure on fixed assets in year	million $	4,048	3,653	3,194	2,789	2,609	2,603	2,617	2,719	2,847	3,006	2,207
Total assets, less accumulated depreciation	million $	43,244	39,373	36,277	34,358	32,657	31,357	29,320	27,301	23,194	20,721	17,830
Long-term liabilities and notes payable	million $	32,160	29,378	26,802	26,405	25,566	24,825	23,148	21,555	18,266	16,443	14,197
Transmission line (circuit length)	kilometres	28,478	28,117	27,637	27,591	27,329	27,111	27,105	27,022	27,030	26,875	26,596
Distribution line (3)	kilometres	107,905	106,805	105,880	104,771	103,703	102,740	103,003	102,128	101,769	101,562	101,211
Average number of employees in year		35,705	36,474	34,076	32,473	32,147	32,405	31,166	29,613	31,233	32,654	30,850
Number of associated municipal electrical utilities		311	314	315	316	316	316	316	319	320	324	324
Ultimate customers served by Ont. Hydro and municipal utilities	thousands	3,696	3,654	3,577	3,456	3,351	3,252	3,172	3,105	3,051	3,004	2,967

(1) Excludes circulating energy flows.
(2) Excludes transmission losses, internal primary loads (construction projects and heavy water plant).
(3) Transmission lines under 50 kV classified distribution beginning in 1980.

FUEL CONSUMED TO PRODUCE ELECTRICITY

Kind of Fuel	Consumed in Year 1991	Consumed in Year 1990	Percentage Change in 1991
Uranium (megagrams)	1,228.0	1,051.5	+16.8
Coal (megagrams)	10,866,730	10,361,572	+ 5.1
Ignition and Combustion Turbine Oil (cubic metres)	42,128	58,441	−27.9
Residual Oil (cubic metres)	252,350	319,750	−21.1

POWER DEVELOPMENT PROJECTS UNDER CONSTRUCTION
as at December 31, 1991

Development	Units		Installation Schedule	Installed Capacity	
	Number	Type		Installed	Under Construction
				kW	kW
Darlington—Lake Ontario near Newcastle	4	TN	1990-91-92-93	1,800,000	1,800,000

TN—Thermal-electric nuclear

POWER RESOURCES AND REQUIREMENTS

The analysis on page 5 of energy made available by Ontario Hydro shows for the total system, the energy obtained from each major source in 1990 and 1991 and the related percentage changes in 1991. The table also shows the primary and secondary energy supplied in each year together with the percentage changes in 1991.

The table of In-Service Dependable Capacity and Primary Demand on page 5 shows the primary peak demand for the month of December and the in-service dependable peak capacity of resources at that time. A separate table on pages 6 and 7 gives the in-service dependable peak capacity of major Ontario Hydro generating stations and contract firm power purchases at the time of the December system peak. Any comparison of total primary peak demand and resources should make allowance for the part of total primary demand that may be interrupted under contracts accepted by the customer. In 1991 this interruptible load over the December peak was approximately 268 megawatts.

The in-service dependable peak capacity of a hydraulic generation station is the estimated output that an analysis of stream-flow conditions indicates the station is capable of producing 98 percent of the time. It can be expected to exceed this output in 49 out of 50 years. Since the stations so rated are distributed on many widely separated watersheds and since all would not be simultaneously affected by stream flows, the amount by which the total hydro-electric generating capacity of the system exceeds the sum of various station capacities represents the diversity in stream flow within the system.

The in-service dependable peak capacity of a thermal generating station is the net peaking capacity of its fully commissioned units minus capacity which is mothballed or frozen.

ENERGY MADE AVAILABLE BY ONTARIO HYDRO

	1991	1990	Increase or Decrease
TOTAL SYSTEM	MW.h	MW.h	%
Generation — Nuclear	70,772,564	59,468,855	19.0
— Fossil	30,011,715	27,458,229	9.3
— Hydraulic	33,928,217	36,630,783	(7.4)
Total Generation	134,712,496	123,557,867	(9.0)
Purchases and Net Other Interchange(1)	4,375,721	13,763,555	(68.2)
Total Resources Generated and Received	139,088,217	137,321,422	1.3
Primary Demand	136,965,556	136,744,134	0.2
Secondary Sales	2,122,661	577,288	267.7

IN-SERVICE DEPENDABLE CAPACITY AND PRIMARY DEMAND DECEMBER PEAK 1991 AND 1990

	1991	1990	Net Increase	
TOTAL SYSTEM	MW	MW	MW	%
In-Service Dependable Capacity				
Generation — Nuclear	12,402.0	11,475.0	927.0	8.1
— Fossil	11,582.7	11,577.5	5.2	0.0
— Hydraulic	6,603.0	6,547.0	56.0	0.9
Total Generation	30,587.7	29,599.5	988.2	3.3
Firm Purchases	0.0	0.0	0.0	0.0
Total Resources	30,587.7	29,599.5	988.2	3.3
Reserve or Deficiency	7,654.7	7,814.5	(159.8)	(2.0)
Primary Peak Demand	22,933.0	21,785.0	1,148.0	5.3
Ratio of Reserve or Deficiency to Primary Demand %	33.4	35.9		

The capacities shown are those available for a 20-minute period at the time of the System Primary Peak Demand in December, the capacity of the purchased power sources being based on the terms of the purchased contract. The Primary Peak Demand shown is the maximum peak for December. Some part of the System Primary Demand is subject to interruption in accordance with contract terms accepted by the customer. The total load subject to such interruptions at the time of the December peak is 268 MW.

ONTARIO HYDRO'S TOTAL RESOURCES—1991

		In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Location	**Nuclear Generating Stations**		
Kincardine	Bruce	6,516.0	42,815,973
Pickering	Pickering	4,124.0	25,994,312
Bowmanville	Darlington	1,762.0	1,962,279
	Total Nuclear Generation	12,402.0	70,772,564
	Fossil Generating Stations		
Atikokan	Atikokan	215.0	660,806
Windsor	Keith	0.0	(4,864)
Toronto	Richard L. Hearn	0.0	(21,614)
Mississauga	Lakeview	2,184.0	4,003,433
Courtright	Lambton	2,040.0	5,802,565
Kingston	Lennox	2,232.0	866,475
Nanticoke	Nanticoke	4,336.0	17,547,647
Thunder Bay	Thunder Bay	320.0	1,139,804
	Combustion Turbine and Diesel-Electric	255.7	17,463
	Total Fossil Generation	11,582.7	30,011,715
River	**Hydraulic Generating Stations**		
Niagara	Sir Adam Beck-Niagara No.1	448.0	2,446,882
	Sir Adam Beck-Niagara No.2	1,324.0	9,349,398
	Pumping-Generating Station	125.0	(121,576)
	Ontario Power	28.0	232,934
	Toronto Power		(459)
Welland Canal	DeCew Falls No.1	31.0	84,606
	DeCew Falls No.2	132.0	935,442
	Adjustment to Niagara River Stations to compensate for use of water by Ontario Hydro rather than by another producer	(75.0)	
St. Lawrence	Robert H. Saunders	707.0	6,690,841
Ottawa	Des Joachims	419.0	2,190,934
	Otto Holden	217.0	1,129,282
	Chenaux	113.0	692,174
	Chats Falls (Ontario half)	86.0	484,576
Madawaska	Mountain Chute	165.0	290,568
	Barrett Chute	172.0	291,083
	Stewartville	166.0	298,072
	Arnprior	78.0	144,639

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ONTARIO HYDRO'S TOTAL RESOURCES—1991

			In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Abitibi		Abitibi Canyon	294.0	1,339,365
		Otter Rapids	177.0	688,047
Mississagi		Aubrey Falls	158.0	132,862
		George W. Rayner	46.0	4,504
		Wells	229.0	321,321
		Red Rock Falls	40.0	179,601
Mattagami		Kipling	142.0	522,653
		Little Long	125.0	550,616
		Harmon	129.0	626,486
Montreal		Lower Notch	254.0	366,351
Nipigon		Pine Portage	112.4	670,037
		Cameron Falls	75.8	467,331
		Alexander	62.4	367,433
English		Caribou Falls	80.3	460,194
		Manitou Falls	59.5	341,002
Kaministikwia		Silver Falls	45.7	201,635
Winnipeg		Whitedog Falls	59.3	345,765
Aguasabon		Aguasabon	45.0	265,459
Various		Other Hydraulic Generating Stations	226.4	938,159
	(1)	Adjustment for Diversity-Total System	106.2	
		Total Hydraulic Generation	6,603.0	33,928,217
		Total Generation	30,587.7	134,712,496
Purchases and Other Interchange				
	(4)	Purchases		
		–Ontario		2,040,004
		–Hydro Quebec		92,337
		–Manitoba Hydro		1,419,749
		–USA		688,640
		Total Purchases	0	4,240,730
	(2)	Other Net Interchange (Net)		134,991
		Total Receipts	0.0	4,375,721
		Total Generated and Received	30,587.7	139,088,217

(1) Adjustment to reconcile the sum of plant capacities with the calculated capacity of the system.
(2) Net scheduled interconnection transactions of other than purchases and sales. These include electrical energy exchanges, carrier transfers, water use adjustments, generating unit rentals.
(3) Installed dependable capacity peak at the time of the December peak minus capacity which is frozen or mothballed.
(4) Dependable capacity is the firm contract commitments at the time of of the December peak.

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Ontario Hydro operates 82 hydro-electric, fossil-fuelled, and nuclear generating stations and an extensive transmission and distribution system across the province.

The Corporation is governed by a Board of Directors. The Board can have up to 22 members. Members and the Chairman, who also serves as Chief Executive Officer of the corporation, are appointed by the Lieutenant-Governor-in-Council of Ontario. The President of the corporation is appointed by the Board of Directors.

Ontario Hydro's head office is located at 700 University Avenue, Toronto, Ontario.

OPERATIONS

STATISTICAL SUMMARY 1992–1982

		1992	1991	1990	1989	1988	1987	1986	1985	1984	1983	1982
In-service dependable peak capacity, December	thousand kW	30,477	30,588	29,600	28,162	28,224	27,414	26,918	24,291	22,613	21,486	21,872
Primary peak demand, December	thousand kW	21,339	22,933	21,785	23,630	23,012	20,524	20,609	20,473	18,052	18,792	16,872
Annual energy generated and received (1)	million kW.h	136,272	139,088	137,321	143,062	139,413	132,970	126,620	124,614	122,920	117,971	111,589
Primary energy demand	million kW.h	134,376	136,966	136,744	140,770	134,395	126,455	120,574	116,049	112,293	106,071	100,836
Secondary sales	million kW.h	1,896	2,123	577	2,292	5,018	6,515	6,046	8,565	10,627	11,900	10,753
Annual energy sold by Ontario Hydro (2) (a)	million kW.h	129,083	131,840	129,690	134,454	131,752	125,626	119,501	117,834	116,590	111,673	105,758
Primary revenue of Ontario Hydro	million $	7,712	7,081	6,462	6,255	5,657	5,084	4,605	4,274	3,783	3,357	2,969
Fixed assets at cost	million $	50,305	46,914	42,962	39,380	36,264	33,567	31,049	28,763	26,216	23,554	20,786
Gross expenditure on fixed assets in year	million $	3,642	4,048	3,653	3,194	2,789	2,609	2,603	2,617	2,719	2,847	3,006
Total assets, less accumulated depreciation	million $	46,671	43,244	39,373	36,277	34,358	32,657	31,357	29,320	27,301	23,194	20,721
Long-term liabilities and notes payable	million $	34,034	32,160	29,378	26,802	26,405	25,566	24,825	23,148	21,555	18,266	16,443
Transmission line (circuit length)	kilometres	28,885	28,478	28,117	27,637	27,591	27,329	27,111	27,105	27,022	27,030	26,875
Distribution line (3)	kilometres	108,800	107,905	106,805	105,880	104,771	103,703	102,740	103,003	102,128	101,769	101,562
Average number of employees in year b		34,839	35,705	36,474	34,076	32,473	32,147	32,405	31,166	29,613	31,233	32,654
Number of associated municipal electrical utilities		311	311	314	315	316	316	316	316	319	320	324
Ultimate customers served by Ont. Hydro and municipal utilities	thousands	3,740	3,696	3,654	3,577	3,456	3,351	3,252	3,172	3,105	3,051	3,004

(1) Excludes circulating energy flows.
(2) Excludes transmission losses, internal primary loads (construction projects and heavy water plant).
(3) Transmission lines under 50 kV classified distribution beginning in 1980.

FUEL CONSUMED TO PRODUCE ELECTRICITY

Kind of Fuel	Consumed in Year 1992	Consumed in Year 1991	Percentage Change in 1992
Uranium (megagrams)	1,172.2	1,228.0	−4.5
Coal (megagrams)	10,219,297	10,866,730	−6.0
Ignition and Combustion Turbine Oil (cubic metres)	42,868	42,128	+1.8
Residual Oil (cubic metres)	248,053	252,350	−1.7

POWER DEVELOPMENT PROJECTS UNDER CONSTRUCTION as at December 31, 1992

Development	Units: Number	Units: Type	Installation Schedule	Installed Capacity: Installed	Installed Capacity: Under Construction
				kW	kW
Darlington—Lake Ontario near Newcastle	4	TN	190-92-93-93	1,800,000	1,800,000

TN—Thermal-electric nuclear

POWER RESOURCES AND REQUIREMENTS

The analysis on page 5 of energy made available by Ontario Hydro shows for the total system, the energy obtained from each major source in 1991 and 1992 and the related percentage changes in 1992. The table also shows the primary and secondary energy supplied in each year together with the percentage changes in 1992.

The table of In-Service Dependable Capacity and Primary Demand on page 5 shows the primary peak demand for the month of December and the in-service dependable peak capacity of resources at that time. A separate table on pages 6 and 7 gives the in-service dependable peak capacity of major Ontario Hydro generating stations and contract firm power purchases at the time of the December system peak. Any comparison of total primary peak demand and resources should make allowance for the part of total primary demand that may be interrupted under contracts accepted by the customer. In 1992 this interruptible load over the December peak was approximately 460 megawatts.

The in-service dependable peak capacity of a hydraulic generation station is the estimated output that an analysis of stream-flow conditions indicates the station is capable of producing 98 percent of the time. It can be expected to exceed this output in 49 out of 50 years. Since the stations so rated are distributed on many widely separated watersheds and since all would not be simultaneously affected by stream flows, the amount by which the total hydro-electric generating capacity of the system exceeds the sum of various station capacities represents the diversity in stream flow within the system.

The in-service dependable peak capacity of a thermal/nuclear generating station is the net peaking capacity of its fully commissioned units minus capacity which is mothballed or frozen.

ENERGY MADE AVAILABLE BY ONTARIO HYDRO

	1992	1991	Increase or Decrease
TOTAL SYSTEM	MW.h	MW.h	%
Generation — Nuclear	66,586,451	70,772,564	(5.9)
— Fossil	28,161,462	30,011,715	(6.2)
— Hydraulic	36,542,388	33,928,217	7.7
Total Generation	131,290,301	134,712,496	(2.5)
Purchases and Net Other Interchange(2)	4,981,531	4,375,721	13.8
Total Resources Generated and Received	136,271,832	139,088,217	(2.0)
Primary Demand	134,376,269	136,965,556	(1.9)
Secondary Sales	1,895,563	2,122,661	(10.7)

IN-SERVICE DEPENDABLE CAPACITY AND PRIMARY DEMAND DECEMBER PEAK 1992 AND 1991

	1992	1991	Net Increase	
TOTAL SYSTEM	MW	MW	MW	%
In-Service Dependable Capacity				
Generation — Nuclear	12,402.0	12,402.0	0.0	0.0
— Fossil	11,583.0	11,582.7	0.3	0.0
— Hydraulic	6,492.0	6,603.0	(111.0)	(1.7)
Total Generation	30,477.0	30,587.7	(110.7)	(0.4)
Firm Purchases	200.0	*200.0	0.0	0.0
Total Resources	30,677.0	30,787.7	(110.7)	(0.4)
Reserve or Deficiency	9,338.0	7,854.7	1,483.3	18.9
Primary Peak Demand	21,339.0	22,933.0	(1,594.0)	(7.0)
Ratio of Reserve or Deficiency to Primary Demand %	43.8	34.3		

The capacities shown are those available for a 20-minute period at the time of the System Primary Peak Demand in December, the capacity of the purchased power sources being based on the terms of the purchased contract. The Primary Peak Demand shown is the maximum peak for December. Some part of the System Primary Demand is subject to interruption in accordance with contract terms accepted by the customer. The total load subject to such interruptions at the time of the December peak is 460 MW.

*1991—revised to include 200 MW firm purchase.

ONTARIO HYDRO'S TOTAL RESOURCES—1992

Location	Nuclear Generating Stations	In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Kincardine	Bruce	6,516.0	37,567,015
Pickering	Pickering	4,124.0	24,288,246
Bowmanville	Darlington	1,762.0	4,731,190
	Total Nuclear Generation	12,402.0	66,586,451
	Fossil Generating Stations		
Atikokan	Atikokan	215.0	385,606
Windsor	Keith	0.0	0
Toronto	Richard L. Hearn	0.0	(13,633)
Mississauga	Lakeview	2,194.0	3,577,517
Courtright	Lambton	2,040.0	6,025,743
Kingston	Lennox	2,220.0	679,423
Nanticoke	Nanticoke	4,336.0	16,405,165
Thunder Bay	Thunder Bay	320.0	1,089,742
	Combustion Turbine and Diesel-Electric	258.0	11,899
	Total Fossil Generation	11,583.0	28,161,462
River	**Hydraulic Generating Stations**		
Niagara	Sir Adam Beck-Niagara No.1	448.0	2,544,853
	Sir Adam Beck-Niagara No.2	1,324.0	9,433,766
	Pumping-Generating Station	125.0	(120,301)
	Ontario Power	28.0	224,826
	Toronto Power		0
Welland Canal	DeCew Falls No.1	31.0	97,733
	DeCew Falls No.2	132.0	1,117,985
	Adjustment to Niagara River Stations to compensate for use of water by Ontario Hydro rather than by another producer	(75.0)	
St. Lawrence	Robert H. Saunders	709.0	6,696,727
Ottawa	Des Joachims	420.0	2,212,341
	Otto Holden	214.0	1,126,870
	Chenaux	115.0	728,534
	Chats Falls (Ontario half)	87.0	522,011
Madawaska	Mountain Chute	164.0	342,585
	Barrett Chute	173.0	347,532
	Stewartville	166.0	353,630
	Arnprior	78.0	164,666

ONTARIO HYDRO'S TOTAL RESOURCES—1992

		In-Service Dependable Capacity MW (3)	Annual Energy Output (Net) MW.h
Abitibi	Abitibi Canyon	294.0	1,329,422
	Otter Rapids	175.0	689,704
Mississagi	Aubrey Falls	158.0	143,455
	George W. Rayner	46.0	17,195
	Wells	229.0	332,595
	Red Rock Falls	40.0	191,539
Mattagami	Kipling	142.0	691,854
	Little Long	125.0	620,189
	Harmon	129.0	708,944
Montreal	Lower Notch	255.0	346,825
Nipigon	Pine Portage	112.9	890,676
	Cameron Falls	76.1	575,216
	Alexander	62.4	443,711
English	Caribou Falls	79.1	676,119
	Manitou Falls	59.5	495,715
Kaministikwia	Silver Falls	45.5	298,119
Winnipeg	Whitedog Falls	56.8	454,223
Aguasabon	Aguasabon	45.0	354,160
Various	Other Hydraulic Generating Stations	225.1	1,488,969
(1)	Adjustment for Diversity-Total System	(2.4)	
	Total Hydraulic Generation	6,492.0	36,542,388
	Total Generation	30,477.0	131,290,301
Purchases and Other Interchange			
(4)	Purchases		
	–Ontario		2,956,618
	–Hydro Quebec		38,134
	–Manitoba Hydro	200.0	1,650,244
	–USA		374,896
	Total Purchases	200.0	5,019,892
(2)	Other Net Interchange (Net)		(38,361)
	Total Receipts	200.0	4,981,531
	Total Generated and Received	30,677.0	136,271,832

(1) Adjustment to reconcile the sum of plant capacities with the calculated capacity of the system.
(2) Net scheduled interconnection transactions of other than purchases and sales. These include electrical energy exchanges, carrier transfers, water use adjustments, generating unit rentals.
(3) Installed dependable capacity peak at the time of the December peak minus capacity which is frozen or mothballed.
(4) Dependable capacity is the firm contract commitments at the time of of the December peak.

ONTARIO HYDRO

ENERGY MADE AVAILABLE
TOTAL RESOURCES
ENERGY SALES
SALES, REVENUE, CUSTOMERS
RETAIL
DIRECTS
MUNICIPAL ELECTRIC UTILITIES

94/12/08

ENERGY MADE AVAILABLE BY ONTARIO HYDRO

TOTAL SYSTEM		1993 MW.h
Generation	- Nuclear	78,498,681.0
	- Fossil	18,016,496.0
	- Hydroelectric	36,788,475.0
Total Generation		133,303,652.0
Purchases and Net Other Interchange		4,980,473.0
Total Resources Generated		138,284,125.0
Primary Energy Demand		133,477,115.0
Secondary Sales		4,807,010.0

IN-SERVICE DEPENDABLE CAPACITY AND PRIMARY DEMAND

TOTAL SYSTEM		1993
In-service depandable capacity		MW
Generation	-Nuclear	14,164.0
	-Fossil	10,445.0
	-Hydroelectric	6,513.0
Total Generation		31,122.0
Firm Purchases		0.0
Nugs		742.0
Total Resources		31,122.0
Reserve or Deficiency		10,605.0
Primary Peak Demand		20,517.0

(Fossil includes CTU's and Nuclear includes commissioning)

source:Lois Brill-Nixon
Supplier Settlements
Electricity Exchange

ONTARIO HYDRO'S TOTAL RESOURCES - 1993

		In-Service Dependable Capacity MW	Annual Energy Output(Net) MW.h
LOCATION	**Nuclear Generating Stations**		
Kincardine	Bruce	6,516.0	27,357,839
Pickering	Pickering	4,124.0	28,987,397
Bowmanville	Darlington	3,524.0	22,153,445
	Total Nuclear Generation	14,164.0	78,498,681
	Fossil Generating Stations		
Atikokan	Atikokan	215.0	468,288
Windsor	Keith	0.0	-14,642
Toronto	Richard L. Hearn	0.0	-10,157
Mississauga	Lakeview	1,056.0	1,279,008
Courtright	Lambton	2,040.0	3,991,215
Kingston	Lennox	2,220.0	-10,158
Nanticoke	Nanticoke	4,336.0	11,458,182
Thunder Bay	Thunder Bay	320.0	843,650
	Combustion Turbine and Diesel-Electric	258.0	11,110
	Total Fossil Generation	10,445.0	18,016,496
River	**Hydroelectric Generating Stations**		
Niagara	Sir Adam Beck-Niagara No. 1	448.0	2,392,730
	Sir Adam Beck-Niagara No.2	1,325.0	9,434,368
	Pumping - Generating Sation	125.0	-120,710
	Ontario Power	28.0	392,492
	Toronto Power	0.0	0
Welland Canal	DeCew Falls No. 1	31.0	94,319
	DeCew Falls No. 2	132.0	1,071,657
	Adjustment to Niagara River Sations to compensate for use of water by Ontario hydro rather than by another producer	-75.0	
St. Lawrence	Robert H. Suanders	709.0	6,980,378
Ottawa	Des Joachims	420.0	2,035,024
	Otto Holden	214.0	1,046,650
	Chenaux	119.0	713,853
Madawaska	Chats Falls (Ontario half)	87.0	523,620
	Mountain Chute	164.0	348,044
	Barrett Chute	173.0	350,761
	Stewartville	166.0	354,580
	Arnprior	78.0	162,062

source:Lois Brill-Nixon
Supplier Settlements
Electricity Exchange

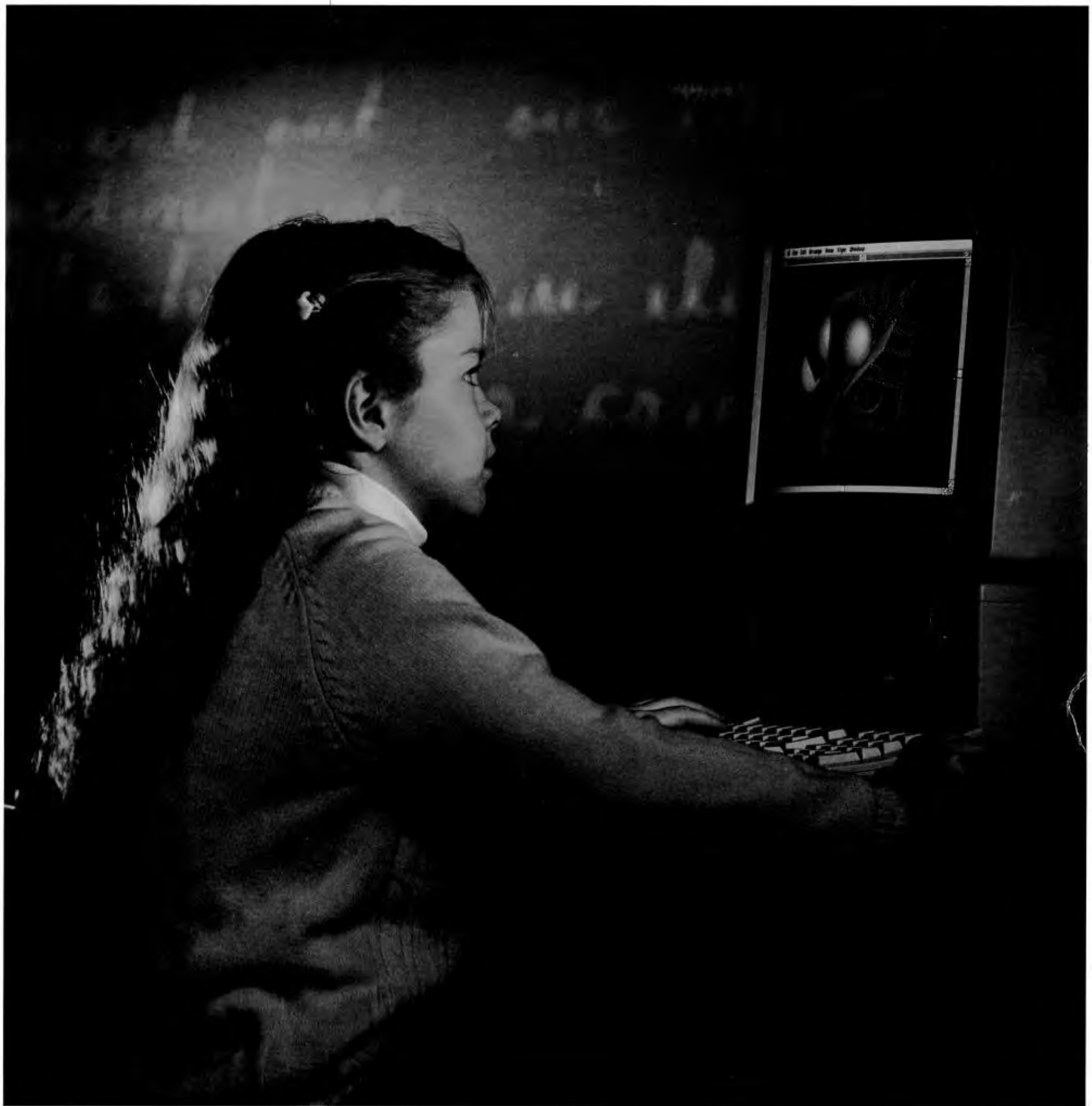
94/12/08

		In-Service Dependable Capacity MW	Annual Energy Output(Net) MW.h
	Abitibi Canyon	294.0	1,551,701
Abitibi	Otter Rapids	175.0	808,238
	Aubrey Falls	158.0	180,631
Mississaugi	George W. Rayner	46.0	67,868
	Wells	229.0	364,559
	Red Rock Falls	40.0	239,551
	Kipling	142.0	738,695
Mattagami	Little Long	125.0	684,215
	Harmon	129.0	719,357
	Lower Notch	255.0	388,473
Montreal	Pine Portage	112.9	829,660
Nipigon	Cameron Falls	76.1	554,911
	Alexander	62.4	463,657
	Caribou Falls	79.1	544,193
English	Manitou Falls	59.5	403,588
	Silver Falls	45.5	239,894
Kaministikwia	Whitedog Falls	56.8	455,394
Winnipeg	Aguasabon	45.0	335,148
Aguasabon	Other Hydroaulic Generating Stat	253.1	1,438,914
Various	Adjustment for Diversity-Total Sy	-14.4	
	Total Hydroelectric Generation	6,513.0	36,788,475
	Total Generation	31,122.0	133,303,652
Purchases and Other Interchange			
	Purchases		
	-Ontario		4,382,123
	-Hydro Quebec		30,891
	-Manitoba Hydro		769,292
	-USA		31,567
	Total Purchases	0.0	5,213,873
	Other Net Interchange (Net)		-233,400
	Total Receipts		4,980,473
	Total Generated and Received	31,122.0	138,284,125

source:Lois Brill-Nixon
Supplier Settlements
Electricity Exchange

ONTARIO HYDRO

ANNUAL REPORT 1989



Choices for Our Future Generation

STATEMENT OF OPERATIONS

for the year ended December 31, 1989	1989	1988
	millions of dollars	
Revenues		
Primary power and energy		
Municipal utilities	4,209	3,824
Rural retail customers	1,256	1,103
Direct industrial customers	790	730
	6,255	5,657
Secondary power and energy (note 1)	91	156
	6,346	5,813
Costs		
Operation, maintenance and administration	1,534	1,354
Fuel used for electric generation	1,132	1,122
Power purchased	230	57
Nuclear agreement - payback	1	11
Provincial government levies (note 2)	177	91
Depreciation (note 3)	845	811
	3,919	3,446
Income before financing charges	2,427	2,367
Interest (note 4)	1,697	1,740
Foreign exchange (note 5)	31	1
	1,728	1,741
Net income	699	626
Appropriation for:		
Debt retirement	357	341
Stabilization of rates and contingencies	342	285
	699	626

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF FINANCIAL POSITION

as at December 31, 1989	1989	1988
	millions of dollars	
Assets		
Fixed assets (note 6)		
Fixed assets in service	27,786	26,918
Less accumulated depreciation	7,017	6,289
	20,769	20,629
Construction in progress	11,593	9,346
	32,362	29,975
Current assets		
Cash and temporary investments	–	312
Accounts receivable	788	663
Fuel for electric generation (note 7)	1,108	1,113
Materials and supplies, at cost	339	332
	2,235	2,420
Other assets		
Unamortized debt costs	218	324
Unamortized advances for fuel supplies (note 8)	728	755
Unamortized deferred costs (note 9)	313	401
Long-term accounts receivable and other assets	421	483
	1,680	1,963
	36,277	34,358

See accompanying summary of significant accounting policies and notes to financial statements.

	1989	1988
	millions of dollars	
Liabilities		
Long-term debt (note 10)	25,141	24,240
Current liabilities		
Bank indebtedness (note 11)	356	–
Accounts payable and accrued charges	919	664
Short-term notes payable	–	500
Accrued interest	742	714
Long-term debt payable within one year	1,661	1,665
	3,678	3,543
Other liabilities		
Long-term accounts payable and accrued charges	222	216
Accrued fixed asset removal and irradiated fuel disposal costs (note 12)	949	771
	1,171	987
Contingencies (notes 8 and 14)		
Equity		
Accumulated debt retirement appropriations	3,927	3,570
Reserve for stabilization of rates and contingencies	2,233	1,891
Contributions from the Province of Ontario as assistance for rural construction	127	127
	6,287	5,588
	36,277	34,358

On behalf of the Board

R6 Franklin

Chairman, President and
Chief Executive Officer

Vice-Chairman

Toronto, Canada,
March 12, 1990

STATEMENT OF ACCUMULATED DEBT RETIREMENT APPROPRIATIONS

for the year ended December 31, 1989

	Municipal Utilities	Power District (Rural Retaial and Direct Industrial Customers)	Total 1989	Total 1988
		millions of dollars		
Balances at beginning of year	2,478	1,092	**3,570**	3,229
Appropriation	241	116	**357**	341
Balances at end of year	2,719	1,208	**3,927**	3,570

STATEMENT OF RESERVE FOR STABILIZATION OF RATES AND CONTINGENCIES

for the year ended December 31, 1989

	Held for the benefit of all customers	Held for the benefit of (or recoverable from) certain groups of customers			Total	
		Municipal Utilities	Rural Retail Customers	Direct Industrial Customers	1989	1988
				millions of dollars		
Balances at beginning of year	1,906	1	(15)	(1)	**1,891**	1,606
Appropriation	311	–	28	3	**342**	285
Balances at end of year	2,217	1	13	2	**2,233**	1,891

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS

for the year ended December 31, 1989	1989	1988
	millions of dollars	
Cash provided from operations (note 13)	1,705	1,368
Cash provided from financing		
Long-term debt issued	3,221	3,402
Change in short-term notes payable issued for debt management purposes - (decrease)	(500)	–
	2,721	3,402
Less long-term debt retired	2,059	1,827
Cash provided from financing	662	1,575
Cash used for investment in other assets (note 13)	(43)	(45)
Cash provided from operations, financing and other activities	2,324	2,898
Changes in cash and cash equivalents - decrease (increase) (note 13)	668	(225)
Cash used for investment in fixed assets	2,992	2,673
Changes in accounts payable and accrued charges affecting investment in fixed assets - increase	103	16
Investment in fixed assets (note 13)	3,095	2,689

See accompanying summary of significant accounting policies and notes to financial statements.

1. Secondary power and energy

Secondary power and energy revenues include $87 million (1988 - $153 million) from sales of electricity to United States utilities.

2. Provincial government levies

	1989	1988
	millions of dollars	
Provincial water rentals	95	91
Provincial debt guarantee fee	82	–
	177	91

Provincial government levies are the amounts charged by the Ontario Provincial Government for the debt guarantee fee and water rentals.

Provincial water rentals
Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydraulic generation.

Provincial debt guarantee fee
In May 1989, the Province of Ontario legislated that Ontario Hydro is required to pay to the Province an annual debt guarantee fee of one half of one per cent on the total outstanding debt guaranteed by the Province as of the preceding December 31. For 1989, the fee of $82 million dollars reflects the fact that the fee came into effect in May 1989.

3. Depreciation

	1989	1988
	millions of dollars	
Depreciation of fixed assets in service	792	774
Amortization of deferred costs	40	40
Fixed asset removal costs		
- provision for fuel channel removal costs	77	39
- provision for decommissioning costs	33	34
- other removal costs	22	25
	964	912
Less:		
Depreciation charged to		
- heavy water production	51	51
- construction in progress	53	44
- fuel for electric generation	2	2
Net gain on sales of fixed assets	13	4
	119	101
	845	811

4. Interest

	1989	1988
	millions of dollars	
Interest on bonds, notes, and other debt	2,932	2,780
Interest on accrued fixed asset removal and irradiated fuel disposal costs	84	65
	3,016	2,845
Less:		
Interest charged to		
- construction in progress	1,016	836
- heavy water production	77	86
- fuel for electric generation	82	90
Interest earned on investments	144	93
	1,319	1,105
	1,697	1,740

5. Foreign exchange

	1989	1988
	millions of dollars	
Amortization of foreign exchange gains and losses	(52)	(61)
Net exchange loss on other foreign transactions	83	62
	31	1

6. Fixed assets

1989	Assets in Service	Accumulated Depreciation	Construction in Progress
		millions of dollars	
Generating stations			
- hydraulic	1,923	657	51
- fossil	3,732	1,539	169
- nuclear	10,874	1,785	8,837
Heavy water	2,507	294	1,316
Transmission and distribution	6,197	1,641	1,122
Heavy water production facilities	1,127	498	–
Administration and service facilities	1,426	603	98
	27,786	7,017	11,593

1988	Assets in Service	Accumulated Depreciation	Construction in Progress
		millions of dollars	
Generating stations			
- hydraulic	1,899	628	33
- fossil	3,707	1,447	66
- nuclear	10,805	1,474	7,258
Heavy water	2,447	252	1,140
Transmission and distribution	5,663	1,511	730
Heavy water production facilities	1,126	445	–
Administration and service facilities	1,271	532	119
	26,918	6,289	9,346

Fossil generating stations in service include non-operating reserve facilities. As at December 31, 1988, substantially all of the undepreciated cost of the non-operating reserve facilities pertained to Lennox unit 3. On December 20, 1989, Lennox unit 3 returned to operation.

A major portion of the construction in progress as at December 31, 1989, relates to the construction program for the Darlington Nuclear Generating Station. The costs associated with this construction program, including heavy water, amounted to $9,885 million as at December 31, 1989 (1988 - $8,209 million). The four generating units at Darlington are planned to be placed in service over the period 1990 through 1992 and will provide 3,524 megawatts of dependable capacity. The estimated cost to complete the Darlington construction program is $2,526 million, including cost escalation and interest of approximately $1,582 million. Cost escalation and interest are forecast to average 5% and 10.5% per year, respectively, over the period 1990 to 1992. Because of the uncertainties associated with long construction lead times and planned in-service dates, the estimated cost to complete is subject to change.

7. Fuel for electric generation	1989	1988
	millions of dollars	
Inventories		
- uranium	700	668
- coal	396	418
- oil	12	27
	1,108	1,113

8. Unamortized advances for fuel supplies	1989	1988
	millions of dollars	
Uranium		
- Rio Algom Limited	406	414
- Denison Mines Limited	322	334
	728	748
Coal	–	7
	728	755

Unamortized advances for fuel supplies are recovered as fuel is delivered. Over the next five years, the amortization of advances for uranium supplies will be about $33 million for the contract with Rio Algom Limited and about $64 million for Denison Mines Limited.

Ontario Hydro has long-term contracts with Denison Mines Limited and Rio Algom Limited for uranium supplies through to 2012 and 2027, respectively. Ontario Hydro's current forecast of the annual requirements for uranium is about 1,700 megagrams for 1990, increasing to about 1,800 megagrams by 1994. The uranium inventory as at December 31, 1989, plus the contracted deliveries through to the end of 1993 exceed the forecasted requirements to the end of 1993 by about 400 megagrams. Starting in 1994 through to 2012, contracted deliveries exceed forecasted requirements of the nuclear generating facilities currently in service and under construction by about 1,000 megagrams per year. Ontario Hydro's options for managing the oversupply include resale of the uranium and, under specified conditions, cancellation or renegotiation of the contracts. In the event that a contract is cancelled, the supplier is not required to refund any outstanding advances. At this time, the outcome with respect to managing the oversupply of uranium is not determinable.

9. Unamortized deferred costs	1989	1988
	millions of dollars	
Bruce Heavy Water Plant "D"	148	185
Wesleyville Generating Station	10	15
	158	200
Fuel oil contract	87	116
Coal Purchase Agreement	68	85
	313	401

Unamortized deferred costs are amounts that the Board of Directors, under its rate setting authority, has determined be deferred and amortized for recovery through electricity rates on a straight-line basis over a specified period of years. The nature of these costs are described below.

- Bruce Heavy Water Plant "D" is an indefinitely deferred project with a low probability of construction being resumed. The capital cost of this project and the unamortized deferred costs associated with the cancelled Wesleyville Generating Station project are being amortized over the period 1984 through 1993. Accordingly, $40 million was charged to depreciation in 1989.

9. Unamortized deferred costs (continued)

- Under the terms of the settlement reached by Ontario Hydro and Petrosar Limited in 1987 with respect to a fuel oil contract, Ontario Hydro paid $150 million to Petrosar Limited and the parties released each other from all obligations and claims related to the contract. The net cost of this settlement is being amortized over the period 1988 through 1992. Accordingly, $29 million was charged to fuel used for electric generation in 1989.
- In November 1987, Ontario Hydro provided USX Corporation with notification of cancellation of the Coal Purchase Agreement pursuant to the three year notice period provision in the Agreement. On cancellation of the Agreement, USX Corporation is not required to refund any outstanding pre-production payments made in advance of the coal deliveries to Ontario Hydro. The outstanding advances and associated costs as at the date of cancellation of the Agreement were estimated to be $85 million and are to be amortized over the period 1989 through 1993. Accordingly, during 1989, $17 million was charged to fuel used for electric generation. In December 1989, Ontario Hydro and USX Corporation agreed to cancel the Agreement as of December 31, 1989 and the net cost of settlement payable by Ontario Hydro was charged to fuel used for electric generation in 1989.

10. Long-term debt	**1989**	1988
	millions of dollars	
Bonds and notes payable	**26,694**	25,775
Other long-term debt	**108**	130
	26,802	25,905
Less payable within one year	**1,661**	1,665
	25,141	24,240

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity and by the currency in which they are payable in the following table:

	1989				1988	
Years of Maturity		Principal Outstanding		Weighted Average Coupon Rate	Principal Outstanding	Weighted Average Coupon Rate
	Canadian	Foreign	Total		Total	
		millions of dollars		*per cent*	*millions of dollars*	*per cent*
1989	–	–	–		1,644	
1990	**1,018**	**621**	**1,639**		1,668	
1991	**1,372**	**273**	**1,645**		1,675	
1992	**1,136**	**900**	**2,036**		1,910	
1993	**2,781**	**41**	**2,822**		2,587	
1994	**1,328**	**563**	**1,891**		–	
1 - 5 years	**7,635**	**2,398**	**10,033**	**11.0**	9,484	10.9
6 - 10 years	**4,868**	**548**	**5,416**	**9.6**	5,256	10.2
11 - 15 years	**3,084**	**567**	**3,651**	**11.6**	3,245	11.9
16 - 20 years	**3,023**	**2,345**	**5,368**	**10.0**	4,726	9.8
21 - 25 years	**1,326**	**900**	**2,226**	**13.5**	3,064	12.6
	19,936	**6,758**	**26,694**	**10.8**	25,775	10.9

Currency in which payable:

	1989	1988
Canadian dollars	**19,936**	17,905
United States dollars	**6,753**	7,858
United Kingdom pounds sterling	**5**	12
	26,694	25,775

Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

10. Long-term debt (continued)

Bonds and notes payable in United States dollars include Canadian $5,096 million (1988 - Canadian $5,689 million) of Ontario Hydro bonds held by the Province of Ontario and having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

Ontario Hydro has entered into financial arrangements to hedge a portion of the foreign currency exposure related to principal and interest payments with respect to long-term debt and these arrangements are primarily in forward exchange contracts. These contracts amounted to United States $1,995 million as at December 31, 1989 (1988 - United States $2,198 million), having a weighted average Canadian dollar exchange rate of 1.26 (1988 - 1.26).

These financial arrangements hedge principal and interest payments amounting to United States $876 million due in 1990 and the remaining United States $1,119 million hedge principal and interest payments due over the period 1991 through 1998.

Ontario Hydro has entered into interest rate swap arrangements amounting to Canadian $120 million in notional principal as at December 31, 1989 (1988 - Canadian $1,380 million), expiring in 1991 through 1994 (1988 - 1989 to 1993). These arrangements have effectively converted fixed interest rates on long-term debt, having a weighted average coupon rate of 11.2% (1988 - 10.0%), to variable interest rates which are adjusted quarterly to the prevailing Canadian bankers' acceptance rate.

Other long-term debt:	Years of Maturity	Interest Rate	1989	1988
		per cent	*millions of dollars*	
Balance due to Atomic Energy of Canada Limited on purchase of Bruce Heavy Water Plant "A"	1992	7.8	67	87
Capitalized lease obligation for the Head Office building, payable in U.S. dollars	2005	8.0	40	42
Capitalized lease obligations for transport and service equipment	1990 to 1994	6.3 to 11.9	1	1
			108	130

Payments required on the above debt, excluding interest, will total $76 million over the next fi.e years. The amount payable within one year is $22 million (1988 - $21 million).

11. Bank indebtedness

Bank indebtedness includes short-term bank lines of credit available to Ontario Hydro in the amount of $600 million. The lines of credit are unsecured and bear interest at the Canadian prime rate.

12. Accrued fixed asset removal and irradiated fuel disposal costs

	1989	1988
	millions of dollars	
Accrued fixed asset removal costs		
- accrued decommissioning costs	267	212
- accrued fuel channel removal costs	250	194
	517	406
Accrued irradiated fuel disposal costs	432	365
	949	771

Fixed asset removal costs

Fixed asset removal costs are the costs of removing certain fuel channels from nuclear reactors which are expected to be replaced during the life of the reactors, and the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives. The significant assumptions used in estimating fixed asset removal costs were:

- removal of fuel channels in Pickering Nuclear Generating Station "A" units 3 and 4 in the 1989 to 1992 (1988 - 1997 to 2000) period, Bruce Nuclear Generating Station "A" units 1 and 2 in the 1996 to 2000 period and units 3 and 4 in the 2002 to 2010 (1988 - 2001 to 2011 for all 4 units) period, Pickering "B" in the 2012 to 2017 (1988 - 2012 to 2017) period and Bruce "B" in the 2014 to 2019 (1988 - 2014 to 2020) period;
- decommissioning of nuclear generating stations in the 2042 to 2065 period on the deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- dismantlement of Bruce Heavy Water Plants "A", "B" and "D" in the 1995 to 2005 period;
- interest rates through to 2065 ranging from 10% to 11% (1988 - 10% to 11%); and
- escalation rates through to 2065 ranging from 4% to 9% (1988 - 4% to 9%).

Because of possible changes to the above factors and the methods used for decommissioning and fuel channel removal, these costs are subject to revision.

Irradiated fuel disposal costs

The significant assumptions used in estimating the future irradiated fuel disposal costs were:

- an in-service date of the year 2010 for irradiated nuclear fuel disposal facilities;
- a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 10% to 11% (1988 - 10% to 11%); and
- escalation rates through to the disposal date ranging from 4% to 9% (1988 - 4% to 9%).

Because of the uncertainties associated with the technology of disposal, and the above factors, these costs are subject to change.

13. Statement of source of cash used for investment in fixed assets

The Statement of Source of Cash Used for Investment in Fixed Assets reports the investment in fixed assets resulting from the cash flows from operations, financing and other activities, and the effects of changes in cash and cash equivalents and changes in accounts payable and accrued charges affecting investment in fixed assets during the year. This statement focuses on the investment in fixed assets in view of Ontario Hydro's current level of construction activities which are financed from two major sources, cash provided from operations and cash provided from financing. Cash provided from financing represents the amount of cash provided from the issuance of long-term debt and the increase in the level of short-term notes payable issued for debt management purposes, less the amount of cash used to retire long-term debt.

13. Statement of source of cash used for investment in fixed assets (continued)

The components of cash provided from operations, cash provided from investment in other assets, and changes in cash and cash equivalents, defined to be cash and temporary investments net of short-term notes payable issued for cash management purposes, are summarized below.

	1989	1988
	millions of dollars	
Cash provided from operations:		
Net Income	699	626
Items not requiring cash in the current year		
Depreciation	845	811
Amortization of foreign exchange gains and losses	(52)	(61)
Provision for irradiated fuel disposal costs	27	26
Nuclear agreement - payback	1	11
Other	177	120
Funds provided from operations	1,697	1,533
Changes in working capital, excluding cash and cash equivalents, and long-term accounts payable affecting operations - (increase) decrease	8	(165)
Cash provided from operations	1,705	1,368
Cash used for investment in other assets:		
Advances and related costs for fuel supplies	(3)	(2)
Less repayments and amortization of advances for fuel supplies	32	27
	29	25
Other	(72)	(70)
Cash used for investment in other assets	(43)	(45)
Changes in cash and cash equivalents:		
Cash and temporary investments - (increase) decrease	668	(223)
Short-term notes payable issued for cash management purposes - (decrease)	—	(2)
Changes in cash and cash equivalents - (increase) decrease	668	(225)

The reconciliation of the change in fixed assets during the year with the investment in fixed assets for the year is summarized below:

	1989	1988
Change in fixed assets	2,387	1,989
Depreciation of fixed assets in service	792	774
Less depreciation charged to heavy water production and construction in progress	(104)	(95)
	688	679
Net book value of fixed assets sold or retired	20	21
Investment in fixed assets	3,095	2,689

14. Pension, insurance and health care

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan and the long-term disability plan. The assets of these plans and the changes in assets during the year are shown in the financial statements of The Pension and Insurance Fund and are not included in Ontario Hydro's financial statements.

Pension Plan

On October 21, 1986, the Ontario Hydro Employees' Union, Local 1000 of the Canadian Union of Public Employees – C.L.C. (OHEU) filed an application for judicial review in the Supreme Court of Ontario to determine whether Ontario Hydro was entitled to apply the pension surplus that had accumulated in Ontario Hydro's Pension Plan to meet the Corporation's contribution obligation with respect to 1986. On May 3, 1989, the Court of Appeal of the Supreme Court of Ontario rendered its decision that Ontario Hydro was not entitled to apply the pension surplus that had accumulated in the Pension Plan to meet the Corporation's contribution with respect to

14. Pension, insurance and health care (continued)

1986, being about $74 million, and ordered Ontario Hydro to contribute such amount to the Pension Plan. In compliance with the Court of Appeal decision, Ontario Hydro paid $71 million into the Pension Plan in January 1990. This amount is comprised of the amount awarded by the Court of Appeal and post-judgement interest, less a prepaid contribution. The amount of $71 million was charged against the accrued pension liability account in Ontario Hydro's Statement of Financial Position.

On December 22, 1989, the OHEU filed an application for judicial review in the Supreme Court of Ontario to require Ontario Hydro to comply with its statutory obligation to contribute the difference between the amount of the contributions of the employees and the amount of the cost of the pension benefits as determined by actuarial valuations for the years 1983, 1984, 1985, 1987, 1988 and 1989, plus prejudgement interest. Ontario Hydro has filed a notice of appearance in response to the application. No amount has been accrued in the 1989 financial statements to provide for the contingency with respect to these years as, at this time, the results of the judicial review are not determinable. Any amount that Ontario Hydro is required to contribute to the Pension Plan with respect to these years will be charged to the accrued pension account in the statement of financial position. In the event that the accrued pension amount does not have future benefit to Ontario Hydro as determined in accordance with the recommendations of the Canadian Institute of Chartered Accountants, it is expected that management would request the Board of Directors specify such loss in value be deferred and amortized to future operations on a basis consistent with its inclusion in electricity rates.

The pension costs for 1989 were $65 million (1988 – $40 million). In 1989, about $49 million (1988 – $30 million) of the pension costs were charged to operations and $16 million (1988 – $10 million) were capitalized.

The pension costs for 1989 were actuarially determined for accounting purposes using the following significant assumptions which take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits – 8.50% (1988 – 8.50%);
- rate used to estimate interest cost and return on investments – 8.50% (1988 – 8.50%);
- salary escalation rate – 7.00% (1988 – 7.00%);
- rate used to estimate ad hoc improvements in pension benefits to partially offset the effect of increase in cost of living – 2.50% (1988 – 2.50%);
- average retirement age for males – 59.1 (1988 – 59.1) and for females – 60.2 (1988 – 60.2); and
- average remaining period of service of the employees – 17 years (1988 – 17 years).

Based on these assumptions, the actuarial present value of the accrued pension benefits is estimated to be $3,524 million as at December 31, 1989 (1988 – $3,182 million), and the pension plan assets available for these benefits were $3,882 million (1988 – $3,451 million).

Group Life Insurance Plan

The group life insurance plan had assets of $21 million as at December 31, 1989 (December 31, 1988 – $25 million). Effective April 1, 1986, the assets are being used to pay both the employee and employer insurance premiums for all members of the plan until such time as the assets are fully utilized.

Group Health Care Plan

Ontario Hydro provides a group health care plan to its employees. In 1989, the cost of providing these benefits was $53 million (1988 – $52 million).

Post Employment Benefits

In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as incurred. In 1989, the cost of providing these benefits was $12 million (1988 – $11 million).

15. Research and development

In 1989 approximately $112 million of research and development costs were charged to operations and $10 million were capitalized (1988 - $88 million and $22 million, respectively).

16. Comparative figures

Certain of the 1988 comparative figures in the Statement of Operations have been reclassified to conform with the 1989 financial statement presentation.

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

	1989	1988	1987	1986	1985
			millions of dollars		
Revenues					
Primary power and energy					
Municipal utilities	4,209	3,824	3,441	3,116	2,891
Rural retail customers	1,256	1,103	968	885	815
Direct industrial customers	790	730	675	604	568
	6,255	5,657	5,084	4,605	4,274
Secondary power and energy	91	156	196	248	351
	6,346	5,813	5,280	4,853	4,625
Costs					
Operation, maintenance and administration	1,534	1,354	1,150	1,014	966
Fuel and fuel-related	1,363	1,190	1,223	1,003	1,061
Provincial government levies	177	91	85	86	82
Depreciation	845	811	723	705	655
	3,919	3,446	3,181	2,808	2,764
Income before financing charges	2,427	2,367	2,099	2,045	1,861
Financing charges					
Gross interest	3,016	2,845	2,744	2,684	2,551
Capitalized interest	(1,175)	(1,012)	(978)	(1,038)	(1,166)
Investment income	(144)	(93)	(64)	(61)	(60)
Foreign exchange	31	1	126	213	176
	1,728	1,741	1,828	1,798	1,501
Net income	699	626	271	247	360
			millions of dollars		
Financial position					
Total assets	36,277	34,358	32,657	31,357	29,320
Fixed assets	32,362	29,975	27,986	26,103	24,149
Long-term debt	25,141	24,240	23,862	23,494	22,518
Equity	6,287	5,588	4,962	4,691	4,444
			millions of dollars		
Cash flows					
Cash provided from operations	1,705	1,368	1,204	1,040	1,055
Cash provided from financing	662	1,575	1,355	1,850	737
Cash used for investment in fixed assets	2,992	2,673	2,452	2,585	2,644
Investment in fixed assets	3,095	2,689	2,524	2,523	2,541
Financial indicators					
Debt ratio(1)	0.817	0.829	0.836	0.835	0.830
Cash flow coverage(2)	1.16	1.19	1.08	1.05	1.02
Interest coverage(3)	1.24	1.23	1.10	1.09	1.14
			millions of kilowatt hours		
Primary energy sales(4)					
By major customer category					
Municipal utilities	93,715	89,607	84,058	80,026	77,011
Rural retail customers	19,767	18,365	16,599	16,279	15,638
Direct industrial customers	20,491	20,096	19,561	18,458	18,011
	133,973	128,068	120,218	114,763	110,660
Secondary energy sales(4)	2,292	5,019	6,515	6,046	8,565
Energy and Demand					
Installed dependable peak capacity (megawatts)(5)	30,271	30,333	30,080	30,701	28,224
December primary peak demand (megawatts)	23,630	23,012	20,524	20,609	20,473
Primary energy made available (millions of kilowatt-hours)(6)	140,770	134,395	126,455	120,574	116,049

	1989	1988	1987	1986	1985
Number of primary customers(4)					
Municipal utilities	315	316	316	316	316
Rural retail customers	891,306	863,039	835,937	813,193	795,022
Direct industrial customers	112	110	108	106	103
	in cents per kilowatt-hour of total energy sales				
Average revenue(4)					
Primary power and energy					
Municipal utilities	4.491	4.268	4.094	3.894	3.754
Rural retail customers	6.801	6.361	6.248	5.901	5.720
Direct industrial customers	3.855	3.633	3.451	3.272	3.155
All primary customers combined	4.715	4.453	4.268	4.058	3.911
Secondary power and energy	3.970	3.108	3.008	4.102	4.098
All classifications combined	4.702	4.402	4.203	4.060	3.925
	expressed as a per cent				
Average rate increases					
Municipal utilities	5.0	4.7	5.2	4.0	8.5
Rural retail customers	5.9	4.4	6.6	3.8	8.7
Direct industrial customers	6.0	5.2	5.6	4.3	8.8
All primary customers combined	5.3	4.7	5.5	4.0	8.6
	in cents per kilowatt-hour of energy generated				
Average cost(4)(7)					
Hydraulic					
Operation, maintenance and administration	.275	.270	.276	.213	.187
Water rentals	.287	.274	.285	.243	.233
Depreciation, debt guarantee fee and financing charges	.389	.386	.465	.413	.399
	.951	.930	1.026	.869	.819
Nuclear					
Operation, maintenance and administration	.739	.623	.508	.481	.479
Uranium	.458	.453	.481	.481	.426
Depreciation, debt guarantee fee and financing charges	2.241	2.078	2.193	2.073	1.889
	3.438	3.154	3.182	3.035	2.794
Fossil					
Operation, maintenance and administration	.600	.530	.488	.550	.437
Coal, gas and oil	2.217	2.258	2.600	2.746	2.609
Depreciation debt guarantee fee and financing charges	.931	.918	.933	1.367	.997
	3.748	3.706	4.021	4.663	4.043
Average number of employees					
Regular	25,147	24,543	24,066	23,373	23,001
Non-regular(8)	8,929	7,930	8,081	9,032	8,135

Footnotes

(1) Debt ratio represents debt (bonds and notes payable, short-term notes payable, other long-term debt, accrued fixed asset removal and irradiated fuel disposal costs and bank indebtedness less unamortized foreign exchange gains and losses) divided by debt plus equity.

(2) Cash flow coverage ratio represents funds provided from operations plus net interest, and interest charged to fuel for electric generation less interest on accrued provisions divided by interest on bonds, notes and other debt.

(3) Interest coverage represents net income plus interest on bonds, notes, and other debt divided by interest on bonds, notes and other debt.

(4) Figures for 1989 are preliminary.

(5) Installed dependable peak capacity represents the net output power supplied by all generating units, and includes non-operating reserve facilities: 1989 - 2,109 megawatts; 1988 - 2,109 megawatts; 1987- 2,667 megawatts; 1986 - 3,784 megawatts; and 1985 - 3,933 megawatts. Also included are net firm power purchase contracts.

(6) Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.

(7) Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.

(8) The majority of non-regular staff are construction trades persons.

FIVE-YEAR SUMMARY OF STATISTICS - CUSTOMERS SERVED BY ONTARIO HYDRO AND ASSOCIATED MUNICIPAL UTILITIES

	1989	1988	1987	1986	1985
			in thousands		
Total number of customers(1)					
Residential	3,041	2,958	2,868	2,781	2,712
Farm	105	106	106	106	107
Commercial and industrial	404	392	377	365	354
	3,550	3,456	3,351	3,252	3,173
			in kilowatt-hours per customer		
Average annual use(1)					
Residential	12,000	11,588	11,019	10,909	10,618
Farm	24,762	24,795	23,547	23,004	22,618
Commercial and industrial	228,000	224,705	220,834	216,666	213,673
			in cents per kilowatt-hour		
Average revenue(1)					
Residential	6.44	6.22	5.98	5.63	5.42
Farm	7.05	6.67	6.48	6.00	5.74
Commercial and industrial	4.87	4.62	4.40	4.20	4.03
All customers	5.35	5.10	4.87	4.63	4.44

Footnote

(1) Figures for 1989 are preliminary.

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Let's Give Tomorrow A Hand

for the year ended December 31, 1990	**1990**	1989
	millions of dollars	
Revenues		
Primary power and energy		
Municipal utilities	**4,373**	4,209
Rural retail customers	**1,297**	1,256
Direct industrial customers	**792**	790
	6,462	6,255
Secondary power and energy (note 1)	**22**	91
	6,484	6,346
Costs		
Operation, maintenance and administration	**1,927**	1,534
Fuel used for electric generation	**1,035**	1,132
Power purchased	**477**	230
Nuclear agreement - payback	**(15)**	1
Provincial government levies (note 2)	**235**	177
Depreciation (note 3)	**908**	845
	4,567	3,919
Income before financing charges	**1,917**	2,427
Financing charges		
Interest (note 4)	**1,803**	1,697
Foreign exchange	**(15)**	31
	1,788	1,728
Net income	**129**	699
Appropriation for:		
Debt retirement	**374**	357
Stabilization of rates and contingencies	**(245)**	342
	129	699

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF FINANCIAL POSITION

as at December 31, 1990	**1990**	1989
	millions of dollars	
ASSETS		
Fixed assets (note 5)		
Fixed assets in service	**32,497**	27,786
Less accumulated depreciation	**7,823**	7,017
	24,674	20,769
Construction in progress	**10,465**	11,593
	35,139	32,362
Current assets		
Accounts receivable	**751**	788
Fuel for electric generation (note 6)	**1,352**	1,108
Materials and supplies, at cost	**398**	339
	2,501	2,235
Other assets		
Unamortized debt costs	**248**	218
Unamortized advances for fuel supplies (note 7)	**709**	728
Unamortized deferred costs (note 8)	**227**	313
Long-term accounts receivable and other assets	**549**	421
	1,733	1,680
	39,373	36,277

See accompanying summary of significant accounting policies and notes to financial statements.

	1990	1989
	millions of dollars	
LIABILITIES		
Long-term debt (note 9)	**27,701**	25,141
Current liabilities		
Bank indebtedness (note 10)	**622**	356
Accounts payable and accrued charges	**727**	919
Short-term notes payable	**108**	-
Accrued interest	**768**	742
Long-term debt payable within one year	**1,677**	1,661
	3,902	3,678
Other liabilities		
Long-term accounts payable and accrued charges	**230**	222
Accrued fixed asset removal and irradiated fuel disposal costs (note 11)	**1,124**	949
	1,354	1,171
CONTINGENCIES (notes 7 and 13)		
EQUITY		
Accumulated debt retirement appropriations	**4,301**	3,927
Reserve for stabilization of rates and contingencies	**1,988**	2,233
Contributions from the Province of Ontario as assistance for rural construction	**127**	127
	6,416	6,287
	39,373	36,277

On behalf of the Board of Directors

Chairman, President and
Chief Executive Officer

Vice-Chairman

Toronto, Canada,
March 11, 1991

STATEMENT OF ACCUMULATED DEBT RETIREMENT APPROPRIATIONS

for the year ended December 31, 1990

	Municipal Utilities	Power District (Rural Retail and Direct Industrial Customers)	Total 1990	Total 1989
		millions of dollars		
Balances at beginning of year	2,719	1,208	**3,927**	3,570
Appropriation	255	119	**374**	357
Balances at end of year	2,974	1,327	**4,301**	3,927

STATEMENT OF RESERVE FOR STABILIZATION OF RATES AND CONTINGENCIES

for the year ended December 31, 1990

	Held for the benefit of all customers	Held for the benefit of certain groups of customers				
		Municipal Utilities	Rural Retail Customers	Direct Industrial Customers	Total 1990	Total 1989
			millions of dollars			
Balances at beginning of year	2,217	1	13	2	**2,233**	1,891
Appropriation (withdrawal)	(250)	-	1	4	**(245)**	342
Balances at end of year	1,967	1	14	6	**1,988**	2,233

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS

for the year ended December 31, 1990	**1990**	1989
	millions of dollars	
Cash provided from operations (note 12)	**754**	1,705
Cash provided from financing		
Long-term debt issued	**4,148**	3,221
Long-term debt retired	**(1,633)**	(2,059)
	2,515	1,162
Changes in cash and cash equivalents - decrease (note 12)	**374**	168
Cash provided from financing	**2,889**	1,330
Cash provided for investment in assets	**3,643**	3,035
Cash used for investment in other assets	**(51)**	(43)
Cash used for investment in fixed assets	**3,592**	2,992
Changes in accounts payable and accrued charges affecting investment in fixed assets - (decrease) increase	**(48)**	103
Investment in fixed assets (note 12)	**3,544**	3,095

See accompanying summary of significant accounting policies and notes to financial statements.

1. Secondary power and energy

Secondary power and energy revenues include $20 million (1989 - $87 million) from sales of electricity to United States utilities.

2. Provincial government levies

	1990	1989
	millions of dollars	
Provincial water rentals	**102**	95
Provincial debt guarantee fee	**133**	82
	235	177

Provincial government levies are the amounts charged by the Ontario provincial government for the debt guarantee fee and water rentals.

Provincial water rentals:
Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydraulic generation.

Provincial debt guarantee fee:
In May 1989, the Province of Ontario legislated that Ontario Hydro is required to pay to the Province an annual debt guarantee fee of one half of one per cent on the total outstanding debt guaranteed by the Province as of the preceding December 31. For 1989, the fee of $82 million reflects the fact that the fee came into effect in May 1989.

3. Depreciation

	1990	1989
	millions of dollars	
Depreciation of fixed assets in service	**858**	792
Amortization of deferred costs	**39**	40
Fixed asset removal costs		
– provision for fuel channel removal costs	**55**	77
– provision for decommissioning costs	**32**	33
– other removal costs	**38**	22
	1,022	964
Less:		
Depreciation charged to – construction in progress	**59**	53
– heavy water production	**50**	51
– fuel for electric generation	**2**	2
Net gain on sales of fixed assets	**3**	13
	114	119
	908	845

4. Interest

	1990	1989
	millions of dollars	
Interest on bonds, notes, and other debt	**3,096**	2,932
Interest on accrued fixed asset removal and irradiated fuel disposal costs	**108**	84
	3,204	3,016
Less:		
Interest charged to – construction in progress	**1,169**	1,016
– heavy water production	**71**	77
– fuel for electric generation	**78**	82
Interest earned on investments	**83**	144
	1,401	1,319
	1,803	1,697

5. Fixed assets

1990

	Assets in Service	*Accumulated Depreciation*	*Construction in Progress*
		millions of dollars	
Generating stations – hydraulic	**1,972**	**689**	**81**
– fossil	**3,992**	**1,630**	**527**
– nuclear	**13,545**	**2,118**	**7,718**
Heavy water	**2,907**	**340**	**1,181**
Transmission and distribution	**7,349**	**1,797**	**839**
Heavy water production facilities	**1,129**	**551**	**-**
Administration and service facilities	**1,603**	**698**	**119**
	32,497	**7,823**	**10,465**

1989

	Assets in Service	*Accumulated Depreciation*	*Construction in Progress*
		millions of dollars	
Generating stations – hydraulic	1,923	657	51
– fossil	3,732	1,539	169
– nuclear	10,874	1,785	8,837
Heavy water	2,507	294	1,316
Transmission and distribution	6,197	1,641	1,122
Heavy water production facilities	1,127	498	-
Administration and service facilities	1,426	603	98
	27,786	7,017	11,593

5. Fixed assets (continued)

A major portion of the construction in progress as at December 31, 1990 relates to the construction program for the Darlington nuclear generating station. The cost of construction in progress associated with this program, including heavy water, amounted to $8,268 million as at December 31, 1990 (1989 - $9,885 million).

Darlington Unit 2 was placed in-service for commercial operation in October 1990. The remaining three units are planned to be placed in-service by the end of 1993. When completed, the Darlington nuclear generating station will provide a total of 3,524 megawatts of dependable capacity. The estimated cost to complete the Darlington construction program is $1,882 million, including cost escalation and interest of approximately $1,197 million. Because of the uncertainties associated with long construction lead times and planned in-service dates, the estimated cost to complete the station is subject to change.

6. Fuel for electric generation

	1990	1989
	millions of dollars	
Inventories – uranium	**733**	700
– coal	**518**	396
– oil	**101**	12
	1,352	1,108

7. Unamortized advances for fuel supplies

	1990	1989
	millions of dollars	
Uranium – Rio Algom Limited	**399**	406
– Denison Mines Limited	**310**	322
	709	728

Unamortized advances for fuel supplies are recovered as fuel is delivered. Over the next five years, the amortization of advances for uranium supplies under the current amortization schedule is expected to be about $32 million for the contract with Rio Algom Limited and about $68 million for Denison Mines Limited (Denison).

Ontario Hydro has long-term contracts with Denison and Rio Algom Limited for uranium supplies through to 2012 and 2027, respectively. Ontario Hydro's current forecast of the annual requirements for uranium is about 1,800 megagrams for 1991, decreasing to about 1,700 megagrams by 1995. The uranium inventory as at December 31, 1990, plus the contracted deliveries through to the end of 1993 exceed the forecasted requirements to the end of 1993 by about 900 megagrams. Starting in 1994 through to 2012, contracted deliveries exceed forecasted requirements of the nuclear generating facilities currently in service and under construction by about 1,000 megagrams per year. Ontario Hydro's options for managing the oversupply include, under specified conditions, cancellation or renegotiation of the contracts. In the event that a contract is cancelled, the supplier is not required to refund any outstanding advances.

On March 11, 1991, Ontario Hydro's Board of Directors authorized management to notify Denison that under the terms of the Uranium Supply Contract (the Contract), the price for uranium concentrate be amended for 1991 and 1992. If Denison accepts the amended price, Ontario Hydro would be required to pay the amended price for uranium concentrate deliveries in 1991 and 1992. If Denison does not accept the amended price, Ontario Hydro may terminate the Contract effective December 31, 1992. However, at this time, the outcome with respect to the notification to Denison is not determinable. If the contract is terminated, it is expected that the outstanding advances and associated costs would not be charged directly to operations but, under the rate setting authority of Ontario Hydro's Board of Directors, would be deferred and amortized for recovery through future electricity rates.

8. Unamortized deferred costs

	1990	1989
	millions of dollars	
Bruce heavy water plant D	111	148
Wesleyville generating station	7	10
	118	158
Fuel oil contract	58	87
Coal purchase agreement	51	68
	227	313

Unamortized deferred costs are amounts from prior years that the Board of Directors, under its rate setting authority, has determined be deferred and amortized for recovery through electricity rates on a straight-line basis over a specified period of years. Accordingly, in 1990, $39 million and $46 million (1989 - $40 million and $46 million) were charged respectively to depreciation and fuel used for electric generation.

9. Long-term debt

	1990	1989
	millions of dollars	
Bonds and notes payable	29,292	26,694
Other long-term debt	86	108
	29,378	26,802
Less payable within one year	1,677	1,661
	27,701	25,141

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity and by the currency in which they are payable in the table shown on the following page.

9. Long-term debt (continued)

	1990				1989	
Years of Maturity	*Principal Outstanding*			*Weighted Average Coupon Rate*	*Principal Outstanding*	*Weighted Average Coupon Rate*
	Canadian	*Foreign*	*Total*		*Total*	
	millions of dollars			*per cent*	*millions of dollars*	*per cent*
1990	–	–	–		1,639	
1991	1,380	273	1,653		1,645	
1992	1,119	902	2,021		2,036	
1993	2,759	41	2,800		2,822	
1994	1,363	564	1,927		1,891	
1995	1,959	738	2,697		–	
1 - 5 years	8,580	2,518	11,098	11.0	10,033	11.0
6 - 10 years	5,908	623	6,531	10.0	5,416	9.6
11 - 15 years	2,541	968	3,509	11.2	3,651	11.6
16 - 20 years	3,446	1,835	5,281	10.4	5,368	10.0
21 - 25 years	971	902	1,873	13.2	2,226	13.5
26 - 30 years	1,000	–	1,000	10.9	–	–
	22,446	6,846	29,292	10.8	26,694	10.8

Currency in which payable:

	1990	1989
Canadian dollars	22,446	19,936
United States dollars	6,846	6,753
United Kingdom pounds sterling	–	5
	29,292	26,694

Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

Bonds and notes payable in United States dollars include Cdn. $5,056 million (1989 - Cdn. $5,096 million) of Ontario Hydro bonds held by the Province of Ontario and having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

Ontario Hydro has entered into financial arrangements to hedge a portion of the foreign currency exposure related to principal and interest payments with respect to long-term debt. These arrangements are primarily in forward exchange contracts and foreign currency swap contracts.

Forward exchange contracts amounted to U.S. $1,128 million as at December 31, 1990 (1989 - U.S. $1,995 million), having a weighted average Canadian dollar exchange rate of 1.27 (1989 - 1.26). These forward exchange contracts hedge principal and interest payments amounting to U.S. $350 million due in 1991 and the remaining U.S. $778 million hedge principal and interest payments due over the period 1992 through 1998. In addition, foreign currency swap contracts exchange U.S. $850 million of principal and interest payments due over the period 1991 through 1995, into Cdn. $1,095 million.

9. Long-term debt (continued)

Other Long-Term Debt:	*Years of Maturity*	*Interest Rate*	**1990**	1989
		per cent	*millions of dollars*	
Balance due to Atomic Energy of Canada Limited on purchase of Bruce heavy water plant A	1992	7.8	**47**	67
Capitalized lease obligation for the Head Office building, payable in U.S. dollars	2005	8.0	**38**	40
Capitalized lease obligations for transport and service equipment	1991 to 1995	6.3 to 11.9	**1**	1
			86	108

Payments required on the above debt, excluding interest, will total $55 million over the next five years. The amount payable within one year is $24 million (1989 - $22 million).

10. Bank indebtedness

Bank indebtedness includes short-term bank lines of credit available to Ontario Hydro in the amount of $600 million. The lines of credit are unsecured and bear interest at the Canadian prime rate.

11. Accrued fixed asset removal and irradiated fuel disposal costs

	1990	1989
	millions of dollars	
Accrued fixed asset removal costs		
- accrued decommissioning costs	**330**	267
- accrued fuel channel removal costs	**278**	250
	608	517
Accrued irradiated fuel disposal costs	**516**	432
	1,124	949

Fixed asset removal costs:

Fixed asset removal costs are the costs of removing certain fuel channels, which are expected to be replaced during the life of the reactors, from the nuclear reactors, and the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives. The significant assumptions used in estimating fixed asset removal costs were:

- removal of fuel channels in Pickering nuclear generating station A Units 3 and 4 in the 1989 to 1992 (1989 - 1989 to 1992) period; Bruce nuclear generating station A Units 1 and 2 in the 1993 to 1999 (1989 - 1996 to 2000) period and Units 3 and 4 in the 2002 to 2010 (1989 - 2002 to 2010) period; Pickering B in the 2012 to 2017 (1989 - 2012 to 2017) period; Bruce B in the 2014 to 2019 (1989 - 2014 to 2019) period; and Darlington nuclear generating station in the 2019 to 2024 period;

11. Accrued fixed asset removal and irradiated fuel disposal costs (continued)

- decommissioning of nuclear generating stations in the 2042 to 2065 period on the deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- dismantlement of Bruce heavy water plants A, B and D in the 1995 to 2005 period;
- interest rates through to 2065 ranging from 9% to 10% (1989 - 10% to 11%); and
- escalation rates through to 2065 ranging from 4% to 7% (1989 - 4% to 9%).

Because of possible changes to the above factors and the methods used for decommissioning and fuel channel removal, these costs are subject to revision.

Irradiated fuel disposal costs:
The significant assumptions used in estimating the future irradiated fuel disposal costs were:

- an in-service date of the year 2025 (1989 - 2010) for irradiated nuclear fuel disposal facilities;
- a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 9% to 10% (1989 - 10% to 11%); and
- escalation rates through to the disposal date ranging from 4% to 7% (1989 - 4% to 9%).

Because of the uncertainties associated with the technology of disposal, and the above factors, these costs are subject to change.

12. Statement of source of cash used for investment in fixed assets

The statement of source of cash used for investment in fixed assets reports the investment in fixed assets resulting from the cash flows from operating and financing activities and the effects of changes in accounts payable and accrued charges affecting investment in fixed assets during the year. This statement focuses on the investment in fixed assets in view of Ontario Hydro's current level of construction activities which are financed from the two sources, cash provided from operations and cash provided from financing.

Cash provided from financing represents the amount of cash provided from the issuance of long-term debt, less the amount of cash used to retire long-term debt; and the effects of changes in cash and cash equivalents, defined to be cash and short-term investments less bank indebtedness and short-term notes payable.

The components of cash provided from operations and changes in cash and cash equivalents are summarized on the next page.

12. Statement of source of cash used for investment in fixed assets (continued)

	1990	1989
	millions of dollars	
Cash provided from operations		
Net Income	**129**	699
Items not requiring cash in the current year:		
Depreciation	**908**	845
Amortization of foreign exchange gains and losses	**(48)**	(52)
Provision for irradiated fuel disposal costs	**35**	27
Other	**121**	178
	1,145	1,697
Changes in non-cash working capital and long-term accounts payable affecting operations - decrease (increase)	**(391)**	8
Cash provided from operations	**754**	1,705

Changes in cash and cash equivalents

	1990	1989
Bank indebtedness - increase	**266**	668
Short-term notes payable - increase (decrease)	**108**	(500)
Changes in cash and cash equivalents	**374**	168

Investment in fixed assets

The reconciliation of the change in fixed assets during the year with the investment in fixed assets for the year is summarized below:

	1990	1989
Change in fixed assets	**2,777**	2,387
Depreciation of fixed assets in service	**858**	792
Less depreciation charged to heavy water production and construction in progress	**(108)**	(104)
	750	688
Net book value of fixed assets sold or retired	**17**	20
Investment in fixed assets	**3,544**	3,095

13. Pension, insurance and health care

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan and the long-term disability plan. The assets of these plans and the changes in assets during the year are shown in the financial statements of The Pension and Insurance Fund and are not included in Ontario Hydro's financial statements.

Pension plan:

On March 30, 1990, the Ontario Hydro Employees' Union, Local 1000 of the Canadian Union of Public Employees - C.L.C. (OHEU) commenced a legal action in the Supreme Court of Ontario. The legal action requires that, among other things, Ontario Hydro comply with the statutory obligation to contribute the difference between the amount of the contributions of the employees and the amount of the cost of the pension benefits as determined by actuarial valuations for the years 1965, 1980 to 1985, and 1987 to 1989, plus pre-judgement interest. Ontario Hydro has filed a notice of appearance in response to the legal action. No amount has been accrued in the 1990 financial statements to provide for the contingency with respect to these years as, at this time, the results of the legal action are not determinable. However, as part of a two-year OHEU contract settlement which includes improvements to pension benefits, Ontario Hydro has agreed to pay $381 million into the Pension Plan over the period 1990 through 1992 in respect of the Corporation's contributions and related interest for all of the years in dispute through 1989. The amount includes $71 million paid by Ontario Hydro in January 1990 pursuant to the Court of Appeal decision regarding 1986 contributions by the Corporation. Interest is payable at The Pension Fund rate of return on the balance unpaid after April 27, 1990. The payments are made without prejudice to any legal defense Ontario Hydro may raise regarding the amounts which may be legally owing in respect of the years in dispute. The amount of $381 million and any additional amount that Ontario Hydro is required to contribute to the Pension Plan with respect to the years in dispute are to be charged to the accrued pension account in the statement of financial position. In the event that the accrued pension amount does not have future benefit to Ontario Hydro as determined in accordance with the recommendations of The Canadian Institute of Chartered Accountants, it is expected that management would request the Board of Directors to specify that such loss in value be deferred and amortized to future operations on a basis consistent with its inclusion in electricity prices.

The pension costs for 1990 were $165 million (1989 - $65 million). In 1990, about $124 million (1989 - $49 million) of the pension costs were charged to operations and $41 million (1989 - $16 million) were capitalized.

The pension costs for 1990 were actuarially determined for accounting purposes using the following significant assumptions which take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits - 8.50% (1989 - 8.50%);
- rate used to estimate interest cost and return on investments - 8.50% (1989 - 8.50%);
- salary escalation rate - 7.00% (1989 - 7.00%);
- rate used to estimate improvements in pension benefits to partially offset the effect of increase in cost of living - 3.75% (1989 - 2.50%);
- average retirement age for males - 60.6 (1989 - 59.1) and for females - 61.5 (1989 - 60.2); and
- average remaining period of service of the employees - 16 years (1989 - 17 years).

Based on these assumptions, the actuarial present value of the accrued pension benefits is estimated to be $4,756 million as at December 31,1990 (1989 - $3,524 million), and the pension plan assets available for these benefits were $4,489 million (1989 - $3,882 million) based on a five-year market value average.

13. Pension, insurance and health care (continued)

Group life insurance plan:

The group life insurance plan had assets of $13 million as at December 31, 1990 (December 31, 1989 - $21 million). Effective April 1, 1986, the assets are being used to pay both the employee and employer insurance premiums for all members of the plan until such time as the assets are fully utilized.

Group health care plan:

Ontario Hydro provides a group health care plan to its employees. In 1990, the cost of providing these benefits was $37 million (1989 - $36 million).

Other post employment benefits:

In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as incurred. In 1990, the cost of providing these benefits was $12 million (1989 - $12 million).

14. Research and development

In 1990 approximately $148 million of research and development costs were charged to operations and $16 million were capitalized (1989 - $112 million and $10 million, respectively).

15. Comparative figures

Certain of the 1989 comparative figures in the statement of source of cash used for investment in fixed assets have been reclassified to conform with the 1990 financial statement presentation.

	1990	1989	1988	1987	
			millions of dollars		
Revenues					
Primary power and energy					
Municipal utilities	**4,373**	4,209	3,824	3,441	3,116
Rural retail customers	**1,297**	1,256	1,103	968	885
Direct industrial customers	**792**	790	730	675	604
	6,462	6,255	5,657	5,084	4,605
Secondary power and energy	**22**	91	156	196	248
	6,484	6,346	5,813	5,280	4,853
Costs					
Operation, maintenance and administration	**1,927**	1,534	1,354	1,150	1,014
Fuel and fuel-related	**1,497**	1,363	1,190	1,223	1,003
Provincial government levies	**235**	177	91	85	86
Depreciation	**908**	845	811	723	705
	4,567	3,919	3,446	3,181	2,808
Income before financing charges	**1,917**	2,427	2,367	2,099	2,045
Financing charges					
Gross interest	**3,204**	3,016	2,845	2,744	2,684
Capitalized interest	**(1,318)**	(1,175)	(1,012)	(978)	(1,038)
Investment income	**(83)**	(144)	(93)	(64)	(61)
Foreign exchange	**(15)**	31	1	126	213
	1,788	1,728	1,741	1,828	1,798
Net income	**129**	699	626	271	247
			millions of dollars		
Financial position					
Total assets	**39,373**	36,277	34,358	32,657	31,357
Fixed assets	**35,139**	32,362	29,975	27,986	26,103
Long-term debt	**27,701**	25,141	24,240	23,862	23,494
Equity	**6,416**	6,287	5,588	4,962	4,691
			millions of dollars		
Cash flows					
Cash provided from operations	**754**	1,705	1,368	1,204	1,040
Cash provided from financing	**2,889**	1,330	1,350	1,397	1,475
Cash used for investment in fixed assets	**3,592**	2,992	2,673	2,452	2,585
Investment in fixed assets	**3,544**	3,095	2,689	2,524	2,523
Financial indicators					
Debt ratio(1)	**0.829**	0.817	0.829	0.836	0.835
Cash flow coverage(2)	**0.94**	1.16	1.19	1.08	1.05
Interest coverage(3)	**1.04**	1.24	1.23	1.10	1.09
			millions of kilowatt-hours		
Primary energy sales(4)					
Municipal utilities	**92,116**	93,715	89,607	84,058	80,026
Rural retail customers	**19,444**	19,767	18,365	16,599	16,279
Direct industrial customers	**19,315**	20,491	20,096	19,561	18,458
	130,875	133,973	128,068	120,218	114,763
Secondary energy sales(4)	**577**	2,292	5,019	6,515	6,046
Energy and Demand					
Installed dependable peak capacity (megawatts)(5)	**31,150**	30,271	30,333	30,080	30,701
December primary peak demand (megawatts)	**21,794**	23,630	23,012	20,524	20,609
Primary energy made available (millions of kilowatt-hours)(6)	**136,744**	140,770	134,395	126,455	120,574

	1990	1989	1988	1987	1986
Number of primary customers(4)					
Municipal utilities	**314**	315	316	316	316
Rural retail customers	**915,027**	891,304	863,039	835,937	813,193
Direct industrial customers	**113**	112	110	108	106
		in cents per kilowatt-hour of total energy sales			
Average revenue(4)					
Primary power and energy					
Municipal utilities	**4.747**	4.491	4.268	4.094	3.894
Rural retail customers	**7.352**	6.801	6.361	6.248	5.901
Direct industrial customers	**4.100**	3.855	3.633	3.451	3.272
All primary customers combined	**5.024**	4.715	4.453	4.268	4.058
Secondary power and energy	**3.813**	3.970	3.108	3.008	4.102
All classifications combined	**5.001**	4.702	4.402	4.203	4.060
		expressed as a per cent			
Average rate increases					
Municipal utilities	**6.1**	5.0	4.7	5.2	4.0
Rural retail customers	**5.3**	5.9	4.4	6.6	3.8
Direct industrial customers	**5.6**	6.0	5.2	5.6	4.3
All primary customers combined	**5.9**	5.3	4.7	5.5	4.0
Average cost(4) (7)		*in cents per kilowatt-hour of energy generated*			
Hydraulic					
Operation, maintenance and administration	**.271**	.275	.270	.276	.213
Water rentals	**.303**	.287	.274	.285	.243
Depreciation, debt guarantee fee and financing charges	**.373**	.389	.386	.465	.413
	.947	.951	.930	1.026	.869
Nuclear					
Operation, maintenance and administration	**1.100**	.739	.623	.508	.481
Uranium	**.490**	.458	.453	.481	.481
Depreciation, debt guarantee fee and financing charges	**2.631**	2.241	2.078	2.193	2.073
	4.221	3.438	3.154	3.182	3.035
Fossil					
Operation, maintenance and administration	**.899**	.600	.530	.488	.550
Coal, gas and oil	**2.479**	2.217	2.258	2.600	2.746
Depreciation, debt guarantee fee and financing charges	**1.274**	.931	.918	.933	1.367
	4.652	3.748	3.706	4.021	4.663
Average number of employees					
Regular	**26,821**	25,147	24,543	24,066	23,373
Non-regular(8)	**9,653**	8,929	7,930	·8,081	9,032

1) Debt ratio represents debt (bonds and notes payable, short-erm notes payable, other long-term debt, accrued fixed asset emoval and irradiated fuel disposal costs and bank indebtedness ess unamortized foreign exchange gains and losses) divided by lebt plus equity.

2) Cash flow coverage ratio represents funds provided from operations plus net interest, and interest charged to fuel for elecric generation less interest on accrued provisions divided by nterest on bonds, notes and other debt.

3) Interest coverage represents net income plus interest on onds, notes, and other debt divided by interest on bonds, notes nd other debt.

4) Figures for 1990 are preliminary.

5) Installed dependable peak capacity represents the net output ower supplied by all generating units, and includes non-operating reserve facilities: 1990 - 1,551 megawatts; 1989 - 2,109 megawatts; 1988 - 2,109 megawatts; 1987 - 2,667 megawatts; and 1986 - 3,784 megawatts. Also included are net firm power purchase contracts.

(6) Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.

(7) Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.

(8) The majority of non-regular staff are construction trades persons.

FIVE-YEAR SUMMARY OF STATISTICS – CUSTOMERS SERVED BY ONTARIO HYDRO AND ASSOCIATED MUNICIPAL UTILITIES

	1990(1)	1989	1988	1987	1986
			in thousands		
Total number of customers					
Residential	**3,100**	3,062	2,958	2,868	2,781
Farm	**105**	105	106	106	106
Commercial and industrial	**420**	407	392	377	365
	3,625	3,574	3,456	3,351	3,252
			in kilowatt-hours per customer		
Average annual use					
Residential	**11,500**	11,856	11,588	11,019	10,909
Farm	**23,933**	24,762	24,795	23,547	23,004
Commercial and industrial	**220,000**	225,103	224,705	220,834	216,666
			in cents per kilowatt-hour		
Average revenue					
Residential	**6.93**	6.50	6.22	5.98	5.63
Farm	**7.41**	7.06	6.67	6.48	6.00
Commercial and industrial	**5.22**	4.88	4.62	4.40	4.20
All customers	**5.56**	5.37	5.10	4.87	4.63

(1) Figures for 1990 are preliminary.

LET'S GIVE TOMORROW A HAND

STATEMENT OF OPERATIONS

for the year ended December 31, 1991

millions of dollars	1991	1990
Revenues		
Primary power and energy		
Municipal utilities	**4,873**	4,373
Rural retail customers	**1,397**	1,297
Direct industrial customers	**811**	792
	7,081	6,462
Secondary power and energy (note 1)	**62**	22
	7,143	6,484
Costs		
Operation, maintenance and administration	**2,037**	1,927
Fuel used for electric generation	**1,128**	1,035
Power purchased	**151**	477
Nuclear agreement – payback	**(6)**	(15)
Provincial government levies (note 2)	**252**	235
Depreciation (note 3)	**1,136**	908
	4,698	4,567
Income before financing charges	**2,445**	1,917
Financing charges		
Interest (note 4)	**2,234**	1,803
Foreign exchange	**7**	(15)
	2,241	1,788
Net income	**204**	129
Appropriation for (withdrawal from):		
Debt retirement	**416**	374
Stabilization of rates and contingencies	**(212)**	(245)
	204	129

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF FINANCIAL POSITION

as at December 31, 1991

millions of dollars	1991	1990
ASSETS		
Fixed assets (note 5)		
Fixed assets in service	34,369	32,497
Less accumulated depreciation	8,744	7,823
	25,625	24,674
Construction in progress	12,545	10,465
	38,170	35,139
Current assets		
Accounts receivable	919	751
Fuel for electric generation (note 6)	1,342	1,352
Materials and supplies, at cost	402	398
	2,663	2,501
Other assets		
Unamortized debt costs	252	248
Unamortized advances for fuel supplies (note 7)	81	709
Unamortized deferred costs (note 8)	858	227
Deferred pension costs	515	—
Unamortized deferred demand management costs	94	9
Long-term accounts receivable and other assets	611	540
	2,411	1,733
	43,244	39,373

See accompanying summary of significant accounting policies and notes to financial statements.

millions of dollars	1991	1990
LIABILITIES		
Long-term debt (note 9)	**30,097**	27,701
Current liabilities		
Bank indebtedness (note 10)	**641**	622
Accounts payable and accrued charges	**876**	727
Short-term notes payable	**94**	108
Accrued interest	**942**	768
Long-term debt payable within one year	**2,063**	1,677
	4,616	3,902
Other liabilities		
Long-term accounts payable and accrued charges	**571**	230
Accrued fixed asset removal and irradiated fuel disposal costs (note 11)	**1,341**	1,124
	1,912	1,354
CONTINGENCIES (note 7)		
EQUITY		
Accumulated debt retirement appropriations	**4,716**	4,301
Reserve for stabilization of rates and contingencies	**1,776**	1,988
Contributions from the Province of Ontario as assistance for rural construction	**127**	127
	6,619	6,416
	43,244	39,373

On behalf of the Board,

M. Eliesen

Chair

President

Toronto, Canada,
March 9, 1992

STATEMENT OF ACCUMULATED DEBT RETIREMENT APPROPRIATIONS

for the year ended December 31, 1991

	1991			1990
	Municipal Utilities	*Power District (Rural Retail and Direct Industrial Customers)*	*Total*	*Total*
millions of dollars				
Balances at beginning of year	**2,974**	**1,327**	**4,301**	3,927
Appropriation	**288**	**128**	**416**	374
Transfers and refunds on annexations by municipal utilities	**14**	**(15)**	**(1)**	–
Balances at end of year	**3,276**	**1,440**	**4,716**	4,301

STATEMENT OF RESERVE FOR STABILIZATION OF RATES AND CONTINGENCIES

for the year ended December 31, 1991

	1991					1990
	Held for the benefit of all customers	*Held for the benefit of certain groups of customers*				
		Municipal Utilities	*Rural Retail Customers*	*Direct Industrial Customers*	*Total*	*Total*
millions of dollars						
Balances at beginning of year	**1,967**	**1**	**14**	**6**	**1,988**	2,233
Appropriation (withdrawal)	**(209)**	**–**	**–**	**(3)**	**(212)**	(245)
Balances at end of year	**1,758**	**1**	**14**	**3**	**1,776**	1,988

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS

for the year ended December 31, 1991

millions of dollars	1991	1990
Cash provided from operations (note 12)	**1,381**	754
Cash provided from financing		
Long-term debt issued	**5,787**	4,148
Long-term debt retired	**(3,044)**	(1,633)
	2,743	2,515
Changes in cash and cash equivalents		
Bank indebtedness – increase	**19**	266
Short-term notes payable – (decrease) increase	**(14)**	108
	5	374
Cash provided from financing	**2,748**	2,889
Cash provided from operations and financing	**4,129**	3,643
Cash used for financing other assets	**(773)**	(51)
Cash used for investment in fixed assets (note 12)	**3,356**	3,592

See accompanying summary of significant accounting policies and notes to financial statements.

1. SECONDARY POWER AND ENERGY

Secondary power and energy revenues include $60 million (1990: $20 million) from sales of electricity to United States utilities.

2. PROVINCIAL GOVERNMENT LEVIES

millions of dollars	1991	1990
Provincial water rentals	**105**	102
Provincial debt guarantee fee	**147**	133
	252	235

Provincial government levies are the amounts charged by the Ontario Provincial Government for the debt guarantee fee and water rentals.

Provincial water rentals

Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydroelectric generation.

Provincial debt guarantee fee

The Province of Ontario has legislated that Ontario Hydro pay to the Province an annual debt guarantee fee of one half of one per cent on the total debt guaranteed by the Province outstanding as of the preceding December 31.

3. DEPRECIATION

millions of dollars	1991	1990
Depreciation of fixed assets in service	**991**	858
Amortization of deferred costs	**39**	39
Fixed asset removal costs	**140**	87
Other removal costs	**84**	38
	1,254	1,022
Less:		
Depreciation charged to – construction in progress	**68**	59
– heavy water production	**50**	50
– fuel for electric generation	**2**	2
Other	**(2)**	3
	118	114
	1,136	908

4. INTEREST

millions of dollars	1991	1990
Interest on bonds, notes, and other debt	**3,462**	3,096
Interest on accrued fixed asset removal and irradiated fuel disposal costs	**121**	108
	3,583	3,204
Less:		
Interest charged to – construction in progress	**1,093**	1,169
– heavy water production	**62**	71
– fuel for electric generation	**38**	78
Interest earned on investments	**156**	83
	1,349	1,401
	2,234	1,803

5. FIXED ASSETS

1991

millions of dollars	*Assets in Service*	*Accumulated Depreciation*	*Construction in Progress*
Generating stations – hydroelectric	**2,172**	**714**	**473**
– fossil	**3,972**	**1,705**	**664**
– nuclear	**14,184**	**2,561**	**8,935**
Heavy water	**2,909**	**391**	**1,453**
Transmission and distribution	**8,192**	**1,979**	**895**
Heavy water production facilities	**1,129**	**603**	**–**
Administration and service facilities	**1,811**	**791**	**125**
	34,369	**8,744**	**12,545**

1990

millions of dollars	*Assets in Service*	*Accumulated Depreciation*	*Construction in Progress*
Generating stations – hydroelectric	1,972	689	81
– fossil	3,992	1,630	527
– nuclear	13,545	2,118	7,718
Heavy water	2,907	340	1,181
Transmission and distribution	7,349	1,797	839
Heavy water production facilities	1,129	551	–
Administration and service facilities	1,603	698	119
	32,497	7,823	10,465

5. FIXED ASSETS *continued*

A major portion of the construction in progress as at December 31, 1991 relates to the construction program for the Darlington nuclear generating station. The cost of construction in progress associated with this program, including heavy water, amounted to $9,482 million as at December 31, 1991 (1990: $8,268 million).

Darlington Unit 2 was declared in-service for commercial operation in October 1990. In December 1990, investigation into a refuelling problem in this unit revealed damage to some fuel bundles. As a consequence, the unit was shut down in January 1991 for more detailed inspection and investigation of the problem. Although the investigation is not yet complete, Unit 2 is expected to be restarted in the second half of 1992. Unit 1 was being commissioned when it was shut down in March 1991 in order to carry out planned tests and inspection for potential fuel bundle damage. Unit 1 was restarted in December 1991 and reached full power in January 1992 before being shut down for further tests and inspection. Units 1 and 3 are forecast to be declared in-service in the second half of 1992. Unit 4 is planned to be placed in-service in 1993. When completed, the Darlington nuclear generating station will provide a total of 3,524 megawatts of dependable capacity. The estimated cost to complete the Darlington construction program is $1,149 million, including cost escalation and interest of approximately $754 million. Because of the uncertainties associated with long construction lead times and planned in-service dates, the estimated cost to complete the station is subject to change.

6. FUEL FOR ELECTRIC GENERATION

millions of dollars

	1991	1990
Inventories – uranium	**773**	733
– coal	**483**	518
– oil	**86**	101
	1,342	1,352

7. UNAMORTIZED ADVANCES FOR FUEL SUPPLIES

millions of dollars

	1991	1990
Uranium – Rio Algom Limited	**68**	399
– Denison Mines Limited	**13**	310
	81	709

In prior years, Ontario Hydro entered into long-term contracts with Rio Algom Limited (Rio Algom) and Denison Mines Limited (Denison) for uranium supplies.

Rio Algom Limited: In June 1991, Ontario Hydro and Rio Algom agreed to amend the long-term uranium supply contract (Rio Algom Contract). The amendments include lowering the prices for deliveries of uranium concentrates over the period 1991 through 1996. In addition, Ontario Hydro and Rio Algom agreed to terminate the Rio Algom Contract effective December 31, 1996. At the expiration of the Rio Algom Contract, Rio Algom is not required to refund any outstanding advances that Ontario Hydro has made for pre-production costs and Ontario Hydro is required to pay for mine related termination costs, including mine shutdown. Ontario Hydro will make contributions totalling $65 million over the period 1991 through 1993, for use in carrying out the Ontario government's Elliot Lake Region Economic Development Program (Elliot Lake Program). The outstanding advances and associated costs at the expiration of the Rio Algom Contract,

7. UNAMORTIZED ADVANCES FOR FUEL SUPPLIES *continued*

the estimated mine-related termination costs and the contributions to the Elliot Lake Program are estimated to total $448 million. This amount will not be charged directly to operations in 1991, since the Board of Directors, under its rate setting authority, determined that this amount will be deferred and amortized for recovery through future electricity rates on a straight-line basis over the period 1994 through 2003 (see note 8).

Denison Mines Limited: In April 1991, Ontario Hydro notified Denison, pursuant to the provisions in the contract, that the long-term uranium supply contract (Denison Contract) will be terminated effective January 1, 1993. On termination of the Denison Contract, Denison is not required to refund any outstanding advances that Ontario Hydro has made for pre-production costs. The outstanding advances and associated costs at the effective date of cancellation of the Denison Contract are estimated to be $269 million. This amount will not be charged directly to operations in 1991, since the Board of Directors, under its rate setting authority, determined that this amount will be deferred and amortized for recovery through electricity rates on a straight-line basis over the period 1992, the first year such cost can be reflected in rates, through 2001 (see note 8).

In November 1991, Denison submitted to Ontario Hydro a statement containing its proposed estimated price to be billed to Ontario Hydro for uranium deliveries in 1992. The statement included a significant additional amount for depreciation and other costs, which Denison claims result from a revision to the estimated life of its Elliot Lake uranium mine as a consequence of the contract termination by Ontario Hydro and Denison's decision to close the mine. Ontario Hydro informed Denison that its statement did not represent compliance by Denison with its obligations to deliver a valid estimate of the cost of production of a pound of uranium concentrates for 1992. The position being asserted by Denison would result in additional charges estimated to be in excess of $300 million related to uranium deliveries in 1991 and 1992. On January 30, 1992, Ontario Hydro initiated legal action against Denison in the Ontario Court (General Division) disputing such charges and requesting the Court to rule on certain aspects of the Denison Contract with respect to the dispute. Subsequently, on February 27, 1992, Denison applied to the Court for an order staying Ontario Hydro's legal action on the grounds that the dispute is required to be submitted to arbitration pursuant to the Denison Contract. At this time, the outcome of the dispute is not determinable, and as such, no provision has been accrued in Ontario Hydro's financial statements with respect to any amounts in dispute.

8. UNAMORTIZED DEFERRED COSTS

millions of dollars	**1991**	1990
Bruce heavy water plant D	**74**	111
Wesleyville generating station	**4**	7
Fuel oil contract	**29**	58
Coal purchase agreement	**34**	51
Uranium supply contracts	**717**	–
	858	227

Unamortized deferred costs are amounts that the Board of Directors, under its rate setting authority, has determined be deferred and amortized for recovery through electricity rates on a straight-line basis over a specified period of years.

As a result of the decision taken in 1991 by Ontario Hydro to amend the Rio Algom Limited and cancel the Denison Mines Limited long-term uranium supply contracts, $592 million was transferred from "Unamortized advances for fuel supplies" (see note 7).

In 1991, $40 million and $46 million (1990: $39 million and $46 million) were charged respectively to depreciation and fuel used for electric generation.

9. LONG-TERM DEBT

millions of dollars	1991	1990
Bonds and notes payable	**32,098**	29,292
Other long-term debt	**62**	86
	32,160	29,378
Less payable within one year	**2,063**	1,677
	30,097	27,701

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity and by the currency in which they are payable in the following table:

Years of Maturity	1991 *Principal Outstanding*			1991 *Weighted Average Interest Rate*	1990 *Principal Outstanding*	1990 *Weighted Average Interest Rate*
	Canadian	*Foreign*	*Total*		*Total*	
	millions of dollars			*per cent*	*millions of dollars*	*per cent*
1991	–	–	–		1,653	
1992	**1,139**	**898**	**2,037**		2,021	
1993	**2,799**	**41**	**2,840**		2,800	
1994	**1,323**	**562**	**1,885**		1,927	
1995	**1,836**	**735**	**2,571**		2,697	
1996	**2,461**	**164**	**2,625**		–	
1 - 5 years	**9,558**	**2,400**	**11,958**	**10.8**	11,098	11.0
6 - 10 years	**6,734**	**1,127**	**7,861**	**10.4**	6,531	10.0
11 - 15 years	**1,782**	**370**	**2,152**	**10.8**	3,509	11.2
16 - 20 years	**3,403**	**2,192**	**5,595**	**10.5**	5,281	10.4
21 - 25 years	**648**	**534**	**1,182**	**11.8**	1,873	13.2
26 years and over	**3,350**	–	**3,350**	**10.4**	1,000	10.9
	25,475	**6,623**	**32,098**	**10.6**	29,292	10.8
Currency in which payable:						
Canadian dollars			**25,475**		22,446	
United States dollars			**6,496**		6,846	
Swiss francs			**127**		–	
			32,098		29,292	

9. LONG-TERM DEBT *continued*

Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

Bonds and notes payable in United States dollars include $4,292 million (1990: $5,056 million) of Ontario Hydro bonds held by the Province of Ontario and having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

Ontario Hydro has entered into financial arrangements as a vehicle for setting the interest rates in advance of future bond issues. As at December 31, 1991, obligations to sell $717 million of Government of Canada bonds in 1992 were outstanding (1990: nil).

Ontario Hydro has entered into financial arrangements to hedge a portion of the foreign currency exposure related to long-term debt. These arrangements are in forward exchange contracts, foreign currency swap contracts and foreign currency options. Forward exchange contracts amounted to US$2,834 million as at December 31, 1991 (1990: US$1,128 million), having a weighted average Canadian dollar exchange rate of 1.22 (1990: 1.27). These forward exchange contracts hedge principal and interest payments amounting to US$1,567 million due in 1992 and the remaining US$1,267 million hedge principal and interest payments due over the period 1993 through 1998. Foreign currency swap contracts to exchange US$897 million and Swiss franc 261 million of principal and interest payments into Canadian dollars were outstanding as at December 31, 1991 (1990: US$850 million). Of this, US$60 million and Swiss franc 11 million are due in 1992, and US$837 million and Swiss franc 250 million are due over the period 1993 to 2001. Option contracts giving Ontario Hydro the right to buy US$135 million were outstanding as at December 31, 1991 (1990: nil).

Other long-term debt

	Years of Maturity	Interest Rate	**1991**	1990
		per cent	*millions of dollars*	*millions of dollars*
Balance due to Atomic Energy of Canada Limited on purchase of Bruce heavy water plant A	1992	7.8	**24**	47
Capitalized lease obligation for the Head Office building, payable in US dollars	2005	8.0	**38**	39
			62	86

Payments required on the above debt, excluding interest, will total $34 million over the next five years. The amount payable within one year is $26 million (1990: $24 million).

10. BANK INDEBTEDNESS

Bank indebtedness includes short-term bank lines of credit available to Ontario Hydro in the amount of $600 million. The lines of credit are unsecured and bear interest at approximately the Canadian prime rate.

11. ACCRUED FIXED ASSET REMOVAL AND IRRADIATED FUEL DISPOSAL COSTS

millions of dollars	1991	1990
Accrued fixed asset removal costs		
– accrued decommissioning costs	376	330
– accrued fuel channel removal costs	347	278
	723	608
Accrued irradiated fuel disposal costs	618	516
	1,341	1,124

Fixed asset removal costs

Fixed asset removal costs are the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives, and the costs of removing certain fuel channels which are expected to be replaced during the life of the nuclear reactors. The significant assumptions used in estimating fixed asset removal costs were:

- decommissioning of nuclear generating stations in the 2042 to 2065 period on the deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- dismantlement of Bruce heavy water plants A, B and D in the 1995 to 2005 period;
- interest rates through to 2065 ranging from 9% to 11% (1990: 9% to 10%);
- escalation rates through to 2065 ranging from 4% to 7% (1990: 4% to 7%); and
- removal of fuel channels in Pickering nuclear generating station A Unit 4 in the 1991 to 1993 (1990: Units 3 and 4 in the 1989 to 1992) period, Bruce nuclear generating station A Units 1 and 2 in the 1993 to 1999 (1990: 1993 to 1999) period and Units 3 and 4 in the 2002 to 2010 (1990: 2002 to 2010) period, Pickering B in the 2012 to 2017 (1990: 2012 to 2017) period, Bruce B in the 2014 to 2019 (1990: 2014 to 2019) period, and Darlington nuclear generating station in the 2019 to 2024 (1990: 2019 to 2024) period.

Because of possible changes to the above factors and the methods used for decommissioning and fuel channel removal, these costs are subject to revision.

Irradiated fuel disposal costs

The significant assumptions used in estimating the future irradiated fuel disposal costs were:

- an in-service date of the year 2025 (1990: 2025) for irradiated nuclear fuel disposal facilities;
- a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 9% to 11% (1990: 9% to 10%); and
- escalation rates through to the disposal date ranging from 4% to 7% (1990: 4% to 7%).

Because of the uncertainties associated with the technology of disposal, and the above factors, these costs are subject to change.

12. STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS

The statement of source of cash used for investment in fixed assets reports the investment in fixed assets resulting from the cash flows from operating and financing activities and the effects of changes in accounts payable and accrued charges affecting investment in fixed assets during the year. This statement focuses on cash used for investment in fixed assets in view of Ontario Hydro's current level of construction activities which are financed from the two sources, cash provided from operations and cash provided from financing. Cash provided from financing represents the amount of cash provided from the issuance of long-term debt, less the amount of cash used to retire long-term debt, and the effects of changes in cash and cash equivalents, defined to be cash and short-term investments less bank indebtedness and short-term notes payable.

The components of cash provided from operations and the reconciliation of investment in fixed assets to cash used for investment in fixed assets are summarized below:

millions of dollars	**1991**	1990
Cash provided from operations		
Net Income	**204**	129
Items not requiring cash in the current year		
Depreciation	**1,136**	908
Amortization of foreign exchange gains and losses	**(22)**	(48)
Provision for irradiated fuel disposal costs	**45**	35
Other	**42**	121
	1,405	1,145
Changes in non-cash working capital and long-term accounts payable affecting operations – (increase)	**(24)**	(391)
Cash provided from operations	**1,381**	754
Investment in fixed assets		
The reconciliation of the change in fixed assets during the year with the investment in fixed assets and cash used for investment in fixed assets for the year:		
Change in fixed assets	**3,031**	2,777
Depreciation of fixed assets in service	**991**	858
Less depreciation charged to heavy water production and construction in progress	**(119)**	(108)
	872	750
Net book value of fixed assets sold or retired	**31**	17
Investment in fixed assets	**3,934**	3,544
Changes in accounts payable and accrued charges affecting investment in fixed assets – (increase) decrease	**(578)**	48
Cash used for investment in fixed assets	**3,356**	3,592

13. PENSION, INSURANCE AND HEALTH CARE

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan and the long-term disability plan. The assets of these plans and the changes in assets during the year are shown in the financial statements of The Pension and Insurance Fund and are not included in Ontario Hydro's financial statements.

Pension Plan

In June 1991, Ontario Hydro and the Ontario Hydro Employees' Union, Local 1000 of the Canadian Union of Public Employees—C.L.C. (the Union) reached a settlement regarding the monetary claims related to the Corporation's contributions for the years 1965, 1980 to 1985 and 1987 to 1989. Pursuant to the terms of the settlement, Ontario Hydro agreed to pay into the Pension Plan an additional $228 million, plus interest at the pension fund rate of return on this amount from January 1, 1991 to the payment date. The Society of Ontario Hydro Professional and Administrative Employees agreed with the terms of the settlement. Court approval, which ensures that the settlement is binding upon all current and former Pension Plan members and their beneficiaries, was obtained in November 1991. Ontario Hydro has since paid the $228 million plus interest into the Pension Plan. The amount paid was charged to the "Deferred pension cost" account in the statement of financial position and the balance in this account represents the cumulative difference between the annual funding contributions and the annual pension costs. Ontario Hydro and the Union also agreed to proceed to court with the remaining issues pertaining to the governance of the Pension Plan.

The pension costs for 1991 were $143 million (1990: $165 million). In 1991, about $94 million (1990: $124 million) of the pension costs were charged to operations and $49 million (1990: $41 million) were capitalized.

The pension costs for 1991 were actuarially determined for accounting purposes using the following significant assumptions which take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits – 8.75% (1990: 8.50%);
- rate used to estimate interest cost – 8.75% (1990: 8.50%);
- rate used to estimate return on investments – 9.75% (1990: 8.50%)
- salary schedule escalation rate – 5.75% (1990: 5.75%);
- rate used to estimate improvements in pension benefits to partially offset the effect of increase in cost of living – 3.75% (1990: 3.75%); and
- average remaining period of service of the employees – 16 years (1990: 16 years).

Based on these assumptions, the actuarial present value of the accrued pension benefits is estimated to be $5,430 million as at December 31, 1991 (1990: $4,756 million), and the pension plan assets available for these benefits were $5,227 million (1990: $4,489 million) based on a five-year market value average.

13. PENSION, INSURANCE AND HEALTH CARE *continued*

Group life insurance plan

The group life insurance plan had assets of $4 million as at December 31, 1991 (December 31, 1990: $13 million). Effective April 1, 1986, the assets are being used to pay both the employee and employer insurance premiums for all members of the plan until such time as the assets are fully utilized.

Group health care plan

Ontario Hydro provides a group health care plan to its employees. In 1991, the cost of providing these benefits was $42 million (1990: $37 million).

Other post-employment benefits

In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as the benefits are incurred. In 1991, the cost of providing these benefits was $14 million (1990: $12 million).

14. RESEARCH AND DEVELOPMENT

In 1991 approximately $145 million of research and development costs were charged to operations and $20 million were capitalized (1990: $148 million and $16 million, respectively).

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

	1991	1990	1989	1988	1987
millions of dollars					
Revenues					
Primary power and energy					
Municipal utilities	**4,873**	4,373	4,209	3,824	3,441
Rural retail customers	**1,397**	1,297	1,256	1,103	968
Direct industrial customers	**811**	792	790	730	675
	7,081	6,462	6,255	5,657	5,084
Secondary power and energy	**62**	22	91	156	196
	7,143	6,484	6,346	5,813	5,280
Costs					
Operation, maintenance and administration	**2,037**	1,927	1,534	1,354	1,150
Fuel and fuel-related	**1,273**	1,497	1,363	1,190	1,223
Provincial government levies	**252**	235	177	91	85
Depreciation	**1,136**	908	845	811	723
	4,698	4,567	3,919	3,446	3,181
Income before financing charges	**2,445**	1,917	2,427	2,367	2,099
Financing charges					
Gross interest	**3,583**	3,204	3,016	2,845	2,744
Capitalized interest	**(1,193)**	(1,318)	(1,175)	(1,012)	(978)
Investment income	**(156)**	(83)	(144)	(93)	(64)
Foreign exchange	**7**	(15)	31	1	126
	2,241	1,788	1,728	1,741	1,828
Net income	**204**	129	699	626	271
Financial position					
Total assets	**43,244**	39,373	36,277	34,358	32,657
Fixed assets	**38,170**	35,139	32,362	29,975	27,986
Long-term debt	**30,097**	27,701	25,141	24,240	23,862
Equity	**6,619**	6,416	6,287	5,588	4,962
Cash flows					
Cash provided from operations	**1,381**	754	1,705	1,368	1,204
Cash provided from financing	**2,748**	2,889	1,330	1,350	1,397
Cash used for investment in fixed assets	**3,356**	3,592	2,992	2,673	2,452
Investment in fixed assets	**3,934**	3,544	3,095	2,689	2,524
Financial indicators					
Interest coverage[1]	**1.06**	1.04	1.24	1.23	1.10
Debt ratio[2]	**0.838**	0.829	0.817	0.829	0.836
millions of kilowatt-hours					
Primary energy sales[3]					
Municipal utilities	**93,623**	92,116	93,715	89,607	84,058
Rural retail customers	**18,988**	19,444	19,767	18,365	16,599
Direct industrial customers	**18,353**	19,315	20,491	20,096	19,561
	130,964	130,875	133,973	128,068	120,218
Secondary energy sales[3]	**2,123**	577	2,292	5,019	6,515
Energy and Demand					
Installed dependable peak capacity *megawatts*[4]	**32,333**	31,350	30,271	30,333	30,080
December primary peak demand *megawatts*	**22,933**	21,785	23,630	23,012	20,524
Primary energy made available *millions of kilowatt-hours*[5]	**136,966**	136,744	140,770	134,395	126,455

	1991	1990	1989	1988	1987
Number of primary customers[3]					
Municipal utilities	**311**	314	315	316	316
Rural retail customers	**925,397**	918,568	894,485	863,049	835,937
Direct industrial customers	**118**	119	116	107	108
in cents per kilowatt-hour of total energy sales					
Average revenue[3]					
Primary power and energy					
Municipal utilities	**5.205**	4.747	4.491	4.268	4.094
Rural retail customers	**7.883**	7.352	6.801	6.361	6.248
Direct industrial customers	**4.419**	4.100	3.855	3.633	3.451
All primary customers combined	**5.419**	5.024	4.715	4.453	4.268
Secondary power and energy	**2.920**	3.813	3.970	3.108	3.008
All classifications combined	**5.419**	5.001	4.702	4.402	4.203
expressed as a per cent					
Average rate increases					
Municipal utilities	**8.7**	6.1	5.0	4.7	5.2
Rural retail customers	**8.7**	5.3	5.9	4.4	6.6
Direct industrial customers	**7.8**	5.6	6.0	5.2	5.6
All primary customers combined	**8.6**	5.9	5.3	4.7	5.5
in cents per kilowatt-hour of energy generated					
Average cost[3,6]					
Hydroelectric					
Operation, maintenance and administration	**.299**	.271	.275	.270	.276
Water rentals	**.338**	.303	.287	.274	.285
Depreciation, debt guarantee fee and financing charges	**.424**	.373	.389	.386	.465
	1.061	.947	.951	.930	1.026
Nuclear					
Operation, maintenance and administration	**1.033**	1.100	.739	.623	.508
Uranium	**.502**	.490	.458	.453	.481
Depreciation, debt guarantee fee and financing charges	**2.756**	2.631	2.241	2.078	2.193
	4.291	4.221	3.438	3.154	3.182
Fossil					
Operation, maintenance and administration	**.839**	.899	.600	.530	.488
Coal, gas and oil	**2.388**	2.479	2.217	2.258	2.600
Depreciation, debt guarantee fee and financing charges	**1.489**	1.274	.931	.918	.933
	4.716	4.652	3.748	3.706	4.021
Average number of employees					
Regular	**28,396**	26,821	25,147	24,543	24,066
Non-regular[7]	**7,309**	9,653	8,929	7,930	8,081

1 Interest coverage represents net income plus interest on bonds, notes, and other debt divided by interest on bonds, notes and other debt.
2 Debt ratio represents debt (bonds and notes payable, short-term notes payable, other long-term debt, accrued fixed asset removal and irradiated fuel disposal costs and bank indebtedness less unamortized foreign exchange gains and losses) divided by debt plus equity.
3 Figures for 1991 are preliminary.
4 Installed dependable peak capacity represents the net output power supplied by all generating units, and includes non-operating reserve facilities: 1991: 1,551 megawatts; 1990: 1,551 megawatts; 1989: 2,109 megawatts; 1988: 2,109 megawatts; and 1987: 2,667 megawatts. Also included are net firm power purchase contracts.
5 Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.
6 Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.
7 The majority of non-regular staff are construction trades persons.

FIVE-YEAR SUMMARY OF STATISTICS
CUSTOMERS SERVED BY ONTARIO HYDRO AND ASSOCIATED MUNICIPAL UTILITIES

	1991[1]	1990	1989	1988	1987
in thousands					
Total number of customers					
Residential	**3,170**	3,129	3,064	2,958	2,868
Farm	**105**	105	105	106	106
Commercial and industrial	**421**	420	408	392	377
	3,696	3,654	3,577	3,456	3,351
in kilowatt-hours per customer					
Average annual use					
Residential	**11,500**	11,668	11,856	11,588	11,019
Farm	**23,944**	23,945	24,762	24,795	23,547
Commercial and industrial	**207,000**	212,193	225,103	224,705	220,834
in cents per kilowatt-hour					
Average revenue[2]					
Residential	**7.24**	6.68	6.25	5.99	5.73
Farm	**7.34**	6.80	6.44	6.14	5.89
Commercial and industrial	**5.68**	5.22	4.88	4.62	4.40
All customers	**6.12**	5.67	5.29	5.03	4.79

1 Figures for 1991 are preliminary
2 Includes rural rate assistance

ONTARIO HYDRO ANNUAL REPORT 1992

STATEMENT OF OPERATIONS

for the year ended December 31, 1992

millions of dollars	**1992**	1991
REVENUES		
Primary power and energy		
Municipal utilities	**5,281**	4,873
Rural retail customers	**1,568**	1,397
Direct industrial customers	**863**	811
	7,712	7,081
Secondary power and energy (note 1)	**56**	62
	7,768	7,143
COSTS		
Operation, maintenance and administration	**2,246**	2,037
Fuel used for electric generation	**1,137**	1,122
Power purchased	**186**	151
Provincial government levies (note 2)	**270**	252
Depreciation (note 3)	**1,198**	1,136
	5,037	4,698
INCOME BEFORE FINANCING CHARGES	**2,731**	2,445
FINANCING CHARGES (note 4)	**2,419**	2,241
NET INCOME	**312**	204

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF FINANCIAL POSITION

as at December 31, 1992

millions of dollars	**1992**	1991
ASSETS		
FIXED ASSETS (note 5)		
Fixed assets in service	**39,997**	34,369
Less accumulated depreciation	**9,615**	8,744
	30,382	25,625
Construction in progress	**10,308**	12,545
	40,690	38,170
CURRENT ASSETS		
Accounts receivable	**1,032**	919
Fuel for electric generation (note 6)	**1,345**	1,342
Materials and supplies, at cost	**351**	402
	2,728	2,663
OTHER ASSETS		
Deferred debt costs	**777**	252
Deferred pension costs (note 15)	**535**	515
Deferred demand management costs	**227**	94
Other deferred costs (notes 7 and 18)	**855**	858
Long-term accounts receivable and other assets	**859**	692
	3,253	2,411
	46,671	43,244

See accompanying summary of significant accounting policies and notes to financial statements.

millions of dollars	**1992**	1991
LIABILITIES		
LONG-TERM DEBT (note 8)	**31,238**	30,097
CURRENT LIABILITIES		
Bank indebtedness (note 9)	**635**	641
Accounts payable and accrued charges	**1,202**	876
Short-term notes payable (note 10)	**898**	94
Accrued interest	**951**	942
Long-term debt payable within one year (note 8)	**2,796**	2,063
	6,482	4,616
OTHER LIABILITIES		
Long-term accounts payable and accrued charges	**503**	571
Accrued fixed asset removal and irradiated fuel disposal costs (note 11)	**1,517**	1,341
	2,020	1,912
CONTINGENCIES (notes 7 and 12)		
EQUITY		
Accumulated debt retirement appropriations	**5,162**	4,716
Reserve for stabilization of rates and contingencies	**1,642**	1,776
Contributions from the Province of Ontario as assistance for rural construction	**127**	127
	6,931	6,619
	46,671	43,244

On behalf of the Board,

Chairman, Board of Directors and Chief Executive Officer

President

Toronto, Canada,
March 8, 1993

STATEMENT OF EQUITY

for the year ended December 31, 1992

millions of dollars	Accumulated Debt Retirement Appropriations	Reserve for Stabilization of Rates and Contingencies	Contributions from the Province	Total 1992	Total 1991
BALANCE AT BEGINNING OF YEAR	4,716	1,776	127	6,619	6,416
Net income (note 13)	312	—	—	312	204
Transfer to satisfy debt retirement appropriation (note 13)	134	(134)	—	—	—
	446	(134)	—	312	204
Net refunds on annexation by municipalities	—	—	—	—	(1)
BALANCE AT END OF YEAR	5,162	1,642	127	6,931	6,619

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS

for the year ended December 31, 1992

millions of dollars	**1992**	1991
CASH PROVIDED FROM OPERATIONS		
Net income	**312**	204
Items not requiring cash in the current year		
Depreciation	**1,198**	1,136
Amortization of foreign exchange gains and losses	**59**	(22)
Provision for irradiated fuel disposal costs	**42**	45
Other	**29**	42
	1,640	1,405
Changes in non-cash working capital and long-term accounts payable affecting operations – decrease (increase) (note 14)	**51**	(24)
Cash provided from operations	**1,691**	1,381
CASH PROVIDED FROM FINANCING (note 14)		
Debt for long-term financing		
Issued	**5,863**	5,787
Retired	**(2,882)**	(2,310)
Redemption of long-term debt, net of reissuances	**(1,197)**	(734)
	1,784	2,743
Changes in cash and cash equivalents		
Bank indebtedness – (decrease) increase	**(6)**	19
Short-term notes used for cash management – increase (decrease)	**33**	(14)
	27	5
Cash provided from financing	**1,811**	2,748
CASH PROVIDED FROM OPERATIONS AND FINANCING	**3,502**	4,129
Cash used for financing other assets	**(127)**	(773)
CASH USED FOR INVESTMENT IN FIXED ASSETS (note 14)	**3,375**	3,356

See accompanying summary of significant accounting policies and notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

1. SECONDARY POWER AND ENERGY

Secondary power and energy revenues include $53 million (1991 – $60 million) from sales of electricity to United States utilities.

2. PROVINCIAL GOVERNMENT LEVIES

millions of dollars	**1992**	1991
Provincial water rentals	**109**	105
Provincial debt guarantee fee	**161**	147
	270	252

Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydraulic generation. The Province of Ontario has legislated that Ontario Hydro pay to the Province an annual debt guarantee fee of one half of one per cent on the total debt guaranteed by the Province outstanding as of the preceding December 31.

3. DEPRECIATION

millions of dollars		**1992**	1991
Depreciation of fixed assets in service		**1,068**	991
Amortization of other deferred costs		**39**	39
Amortization of deferred demand management costs		**13**	3
Fixed asset removal costs		**101**	140
Other removal costs		**105**	84
		1,326	1,257
Less:			
Depreciation charged to	– construction in progress	**74**	68
	– heavy water production	**50**	50
	– fuel for electric generation	**1**	2
Other		**3**	1
		128	121
		1,198	1,136

4. FINANCING CHARGES

millions of dollars		1992	1991
Interest on bonds, notes and other debt		**3,658**	3,465
Interest on accrued fixed asset removal and irradiated fuel disposal costs		**124**	121
		3,782	3,586
Less:			
Interest charged to	– construction in progress	**1,167**	1,093
	– heavy water production	**55**	62
	– fuel for electric generation	**9**	39
Interest earned on investments		**119**	158
		1,350	1,352
Interest charged to operations		**2,432**	2,234
Foreign exchange		**(13)**	7
		2,419	2,241

5. FIXED ASSETS

millions of dollars		1992			1991		
		Fixed Assets in Service	*Accumulated Depreciation*	*Construction in Progress*	*Fixed Assets in Service*	*Accumulated Depreciation*	*Construction in Progress*
Generating stations	– hydraulic	**2,229**	**739**	**559**	2,172	714	473
	– fossil	**4,453**	**1,839**	**783**	3,972	1,705	664
	– nuclear	**17,836**	**2,969**	**6,777**	14,184	2,561	8,935
Heavy water		**3,308**	**444**	**1,334**	2,909	391	1,453
Transmission and distribution		**9,151**	**2,158**	**794**	8,192	1,979	895
Heavy water production facilities		**1,063**	**612**	**—**	1,129	603	—
Administration and service facilities		**1,957**	**854**	**61**	1,811	791	125
		39,997	**9,615**	**10,308**	34,369	8,744	12,545

DARLINGTON NUCLEAR GENERATING STATION

A major portion of the construction in progress as at December 31, 1992 relates to the construction program for the Darlington Nuclear Generating Station. The cost of construction in progress associated with this program, including heavy water, amounted to $6,809 million as at December 31, 1992 (1991 – $9,482 million).

Darlington Unit 2 was declared in service for commercial operation in October 1990. In December 1990, investigation into a refuelling problem in this unit revealed damage to some fuel bundles. As a consequence, unit 2 was shut down in January 1991 for more detailed inspection and investigation of the problem. As a result of this investigation, modifications to the heat transport system were performed and unit 2 was returned to full power in 1992. Darlington Unit 1 was in the commissioning phase when the unit was shut down in March 1991 for investigation into the fuel damage problem discovered in unit 2. During 1991 and 1992, unit 1 was run intermittently for tests to determine the nature of the fuel damage problem. Following modifications to the heat transport system, the unit was declared in service in November 1992. Darlington Unit 3 was declared in service in February 1993 and Unit 4 is planned to be placed in service in the second half of 1993. When completed, the Darlington Nuclear Generating Station will provide a total of 3,524 megawatts of dependable capacity. As at December 31, 1992, the estimated cost to complete the Darlington construction program is $526 million, including cost escalation and interest of approximately $213 million.

6. FUEL FOR ELECTRIC GENERATION

millions of dollars		**1992**	1991
Inventories	– uranium	**725**	773
	– coal	**525**	483
	– oil	**95**	86
		1,345	1,342

7. OTHER DEFERRED COSTS

millions of dollars	**1992**	1991
Bruce Heavy Water Plant "D"	**37**	74
Wesleyville Generating Station	**2**	4
Fuel oil contract	**—**	29
Coal purchase agreement	**17**	34
Denison Mines Limited uranium supply contract	**242**	269
Rio Algom Limited uranium supply contract	**448**	448
Manitoba Hydro power purchase contract	**109**	—
	855	858

Other deferred costs are amounts that the Board of Directors, under its rate setting authority, has determined be deferred and amortized for recovery through electricity rates on a straight-line basis over a specified period of years (see note 18).

As a result of decisions taken in 1991 by Ontario Hydro to cancel the Denison Mines Limited and to amend the Rio Algom Limited long-term uranium supply contracts, the estimated outstanding advances and associated costs at the expiration of the contracts have been deferred and are to be amortized for recovery through future electricity rates on a straight-line basis over the periods 1992 through 2001, and 1994 through 2003, respectively.

In 1989, Ontario Hydro entered into a 22-year contract with Manitoba Hydro (the Contract) to purchase up to 1,000 MW of power per year beginning in the year 2000. On December 17, 1992, due to a projected surplus in generation capacity, Ontario Hydro exercised its right to terminate the Contract. On termination, the Contract requires Ontario Hydro to reimburse Manitoba Hydro for the lesser of $315 million or Manitoba Hydro's internal and out-of-pocket costs. Manitoba Hydro has provided Ontario Hydro with a certificate detailing its costs of

$131 million through to the date of termination, and an estimate of additional costs of up to $6 million to be incurred subsequent to the date of termination. Under the Contract, Ontario Hydro has the right to verify all amounts claimed by Manitoba Hydro. Ontario Hydro's interpretation of the Contract is that its liability is limited to costs incurred by Manitoba Hydro subsequent to entering into the Contract with Ontario Hydro on December 7, 1989. On this basis, on February 25, 1993, Ontario Hydro made a payment of $82 million to Manitoba Hydro. The $82 million payment plus $27 million of related project expenditures incurred directly by Ontario Hydro amount to a $109 million loss on cancellation of the Contract. The $109 million loss will not be charged directly to operations in 1992, since the Board of Directors, under its rate-setting authority, determined that the costs of cancelling the Contract will be deferred and amortized for recovery through future electricity rates on a straight-line basis over the period 1994, the first year such costs can be reflected in rates, through 2003. No provision has been accrued in Ontario Hydro's financial statements with respect to the $49 million difference between the amount claimed of $131 million and the payment of $82 million because Ontario Hydro is of the opinion that costs incurred by Manitoba Hydro before December 7, 1989 are not reimbursable by Ontario Hydro under the Contract; and no provision has been accrued with respect to Manitoba Hydro's estimate of additional costs of up to $6 million to be incurred subsequent to the date of termination of the Contract. Subsequent payments, if any, to Manitoba Hydro with respect to the Contract cancellation will be included in the amount deferred for recovery through future electricity rates.

In 1992, $39 million and $73 million (1991 – $39 million and $46 million) of other deferred costs were charged to depreciation, and fuel used for electric generation, respectively.

8. LONG-TERM DEBT

millions of dollars	**1992**	1991
Bonds and notes payable	**33,994**	32,098
Other long-term debt	**40**	62
	34,034	32,160
Less payable within one year	**2,796**	2,063
	31,238	30,097

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity and by the currency in which they are payable in the following table:

millions of dollars	1992				1991	
				Weighted Average Interest Rate	*Principal Outstanding*	*Weighted Average Interest Rate*
	Principal Outstanding					
YEARS OF MATURITY	*Canadian*	*Foreign*	*Total*	*per cent*	*Total*	*per cent*
1992	—	—	—		2,037	
1993	**2,749**	**45**	**2,794**		2,840	
1994	**1,129**	**617**	**1,746**		1,885	
1995	**1,580**	**808**	**2,388**		2,571	
1996	**2,284**	**181**	**2,465**		2,625	
1997	**912**	**145**	**1,057**		—	
1 – 5 years	**8,654**	**1,796**	**10,450**	**10.6**	11,958	10.8
6 – 10 years	**9,578**	**1,184**	**10,762**	**10.0**	7,861	10.4
11 – 15 years	**1,752**	**638**	**2,390**	**9.7**	2,152	10.8
16 – 20 years	**2,960**	**2,213**	**5,173**	**11.1**	5,595	10.5
21 – 25 years	**598**	**246**	**844**	**10.5**	1,182	11.8
26 years and over	**4,375**	**-**	**4,375**	**10.1**	3,350	10.4
	27,917	**6,077**	**33,994**	**10.3**	32,098	10.6
CURRENCY IN WHICH PAYABLE						
Canadian dollars			**27,917**		25,475	
United States dollars			**5,947**		6,496	
Swiss francs			**130**		127	
			33,994		32,098	

Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

Bonds and notes payable in United States dollars include $4,013 million (1991 – $4,292 million) of Ontario Hydro bonds held by the Province of Ontario and having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

Ontario Hydro has entered into financial arrangements as a vehicle for setting the interest rates in advance of future financing. As at December 31, 1992, obligations to sell $65 million of Government of Canada bonds in 1992 were outstanding (1991 – $717 million).

Ontario Hydro has entered into various financial arrangements to hedge a portion of its foreign currency exposure.

Forward exchange contracts. Forward exchange contracts amounted to US$1,274 million as at December 31, 1992 (1991 – US$2,834 million), having a weighted average Canadian dollar exchange rate of 1.26 (1991 – 1.22). These forward exchange contracts hedge principal and interest payments amounting to US$145 million due in 1993 and the remaining US$1,129 million hedge principal and interest payments due over the period 1994 through 1998.

Foreign currency swap contracts. Foreign currency swap contracts to exchange US$837 million and Swiss franc 250 million of principal and interest payments into Canadian dollars were outstanding as at December 31, 1992 (1991 – US$897 million and Swiss franc 261 million). Of this, US$60 million and Swiss franc 11 million are due in 1993, and US$777 million and Swiss franc 239 million due over the period 1994 to 2001.

Foreign currency options. Option contracts giving Ontario Hydro the right to buy US$713 million were outstanding as at December 31, 1992 (1991 – US$135 million). Option contracts giving holders the right to buy US$713 million from Ontario Hydro were outstanding at December 31, 1992 (1991 – nil).

9. Bank indebtedness

Bank indebtedness includes short-term bank lines of credit available to Ontario Hydro in the amount of $600 million. The lines of credit are unsecured and bear interest at approximately the Canadian prime rate.

10. Short-term notes payable

millions of dollars	**1992**	1991
Short-term notes used for cash management	**127**	94
Short-term notes used for long-term financing	**771**	—
	898	94

During 1992, certain bond issues were called and refinanced at favourable interest rates by issuing short-term notes. Financial arrangements were also entered into so as to achieve a fixed interest rate on the refinanced issues.

11. Accrued fixed asset removal and irradiated fuel disposal costs

millions of dollars	**1992**	1991
Accrued fixed asset removal costs		
– accrued decommissioning costs	**447**	376
– accrued fuel channel removal costs	**374**	347
	821	723
Accrued irradiated fuel disposal costs	**696**	618
	1,517	1,341

Fixed asset removal costs

Fixed asset removal costs are the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives, and the costs of removing certain fuel channels that are expected to be replaced during the life of the nuclear reactors. The significant assumptions used in estimating fixed asset removal costs were:

- decommissioning of nuclear generating stations in the 2042 to 2065 period on the deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- dismantlement of Bruce Heavy Water Plants "A", "B" and "D" in the 1994 to 2005 period;
- interest rates through to 2065 ranging from 9% to 11% (1991 – 9% to 11%);
- escalation rates through to 2065 ranging from 4% to 7% (1991 – 4% to 7%); and
- removal of fuel channels in Pickering Nuclear Generating Station "A" Unit 4 in the 1991 to 1993 (1991 – 1991 to 1993) period, Bruce Nuclear Generating Station "A" Units 1 and 2 in the 1993 to 1999 (1991 – 1993 to 1999) period and Units 3 and 4 in the 2002 to 2010 (1991 – 2002 to 2010) period (see note 18), Pickering "B" in the 2012 to 2017 (1991 – 2012 to 2017) period, Bruce "B" in the 2014 to 2019 (1991 – 2014 to 2019) period, and Darlington Nuclear Generating Station in the 2019 to 2024 (1991 – 2019 to 2024) period.

Because of possible changes to the above factors and the methods used for decommissioning and fuel channel removal, these costs are subject to revision.

IRRADIATED FUEL DISPOSAL COSTS

The significant assumptions used in estimating the future irradiated fuel disposal costs were:

- an in-service date of the year 2025 (1991 – 2025) for irradiated nuclear fuel disposal facilities;
- a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 9% to 11% (1991 – 9% to 11%); and
- escalation rates through to the disposal date ranging from 4% to 7% (1991 – 4% to 7%).

Because of the uncertainties associated with the technology of disposal, and the above factors, these costs are subject to change.

12. CONTINGENCIES

DENISON MINES LIMITED

In April 1991, Ontario Hydro notified Denison Mines Limited (Denison), pursuant to the provisions in the contract, that the long-term uranium supply contract would be terminated effective January 1, 1993. In Denison's 1992 estimated base price and 1991 base price statements for the cost of production of uranium supplied to Ontario Hydro, Denison included significant amounts for depreciation and other costs, which Denison claims result from a revision to the estimated life of its Elliot Lake uranium mine as a consequence of the contract termination by Ontario Hydro and Denison's decision to close the mine. Ontario Hydro rejected both statements as not being in accordance with the requirements of the supply contract. The position being asserted by Denison would result in additional charges to Ontario Hydro estimated to be in excess of $350 million related to uranium deliveries in 1991 and 1992. Ontario Hydro is of the opinion that the parties never intended that Denison be reimbursed for such charges in the event of contract termination. Such charges would be in addition to the requirement that Ontario Hydro forgive the unrefunded portion of the advances made by Ontario Hydro for the mine expansion. Ontario Hydro is also of the opinion that such charges are not a cost of production in accordance with generally accepted accounting principles consistently applied as required by the supply contract. This dispute has been submitted to arbitration and the hearing is expected to commence in March 1993. At this time, the outcome of the dispute involving Denison's claim for significant depreciation and other costs is not determinable, and as such, no provision has been accrued in Ontario Hydro's financial statements with respect to any amounts in dispute.

13. STATEMENT OF EQUITY

The 1992 net income available for appropriation was $312 million. To satisfy the requirements of the Power Corporation Act, $446 million was appropriated for debt retirement, necessitating a withdrawal of $134 million from the reserve for the stabilization of rates and contingencies. In 1991, the amounts were $416 million and $212 million, respectively, and net income was $204 million.

14. STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS

Cash provided from financing represents the amount of cash provided from the issuance of long-term debt and the issuance of short-term notes used for long-term financing, less the amount of cash used to retire or redeem long-term debt, and the effects of changes in cash and cash equivalents. Cash and cash equivalents are defined to be cash and short-term investments less bank indebtedness and short-term notes used for cash management.

The changes in non-cash working capital and long-term accounts payable affecting operations consisted of the following:

millions of dollars	1992	1991
Accounts receivable – (increase)	**(113)**	(167)
Fuel for electric generation – (increase) decrease	**(3)**	10
Materials and supplies – decrease (increase)	**51**	(4)
Accounts payable and accrued charges – increase	**188**	65
Accrued interest – increase	**6**	120
Long-term accounts payable and accrued charges – (decrease)	**(78)**	(48)
	51	(24)

The reconciliation of cash used for investment in fixed assets with investment in fixed assets is shown below:

millions of dollars	1992	1991
Cash used for investment in fixed assets	**3,375**	3,356
Changes in accounts payable and accrued charges affecting investment in fixed assets – increase	**152**	578
Investment in fixed assets	**3,527**	3,934

15. Benefit plans

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan and the long-term disability plan. The assets of these plans and the changes in assets during the year are shown in the financial statements of The Pension and Insurance Fund and are not included in Ontario Hydro's financial statements.

Pension plan

The pension costs for 1992 were $161 million (1991 – $143 million). In 1992, $106 million (1991 – $94 million) of the pension costs were charged to operations and $55 million (1991 – $49 million) were capitalized. The pension costs for 1992 were actuarially determined for accounting purposes using the following significant assumptions, which take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits – 7.00% (1991 – 8.75%);
- rate used to estimate interest cost – 7.00% (1991 – 8.75%);
- rate used to estimate return on investments – 9.00% (1991 – 9.75%);
- salary schedule escalation rate – 4.00% (1991 – 5.75%);
- average long-term rate used to estimate improvements in pension benefits to partially offset the effect of increase in cost of living – 2.81% (1991 – 3.75%); and
- average remaining period of service of the employees – 17 years (1991 – 16 years).

Based on these assumptions, the actuarial present value of the accrued pension benefits is estimated to be $6,386 million as at December 31, 1992 (1991 – $5,430 million), and the pension plan assets available for these benefits were $5,748 million (1991 – $5,227 million) based on a five-year market value average.

Deferred pension costs on the statement of financial position represent the cumulative difference between the funding contributions, including special payments, and pension costs. As at December 31, 1992, the deferred pension costs amounted to $535 million (1991 – $515 million) and primarily reflect special payments made in 1990 and 1991 relating to past service benefit improvements. The costs of pension benefit improvements funded by the special payments are being amortized as a charge to pension costs over the average remaining period of service of the employees.

GROUP LIFE INSURANCE PLAN

From April 1986 to May 1992, the plan assets were used to pay both the employee and employer insurance premiums for all members of the plan. Commencing in June 1992, Ontario Hydro resumed paying premiums for basic insurance coverage and employees resumed paying premiums for additional coverage.

GROUP HEALTH CARE PLAN

Ontario Hydro provides a group health care plan to its employees. In 1992, the cost of providing these benefits was $51 million (1991 – $42 million).

OTHER POST-EMPLOYMENT BENEFITS

In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as the benefits are paid. In 1992, the cost of providing these benefits was $16 million (1991 – $14 million).

16. RESEARCH AND DEVELOPMENT

In 1992, approximately $134 million of research and development costs were charged to operations and $49 million were capitalized (1991 – $145 million and $20 million, respectively).

17. COMPARATIVE FIGURES

Certain of the 1991 comparative figures in the Statement of Financial Position, Statement of Operations and the Statement of Source of Cash Used for Investment in Fixed Assets have been reclassified to conform with the 1992 financial statement presentation.

18. SUBSEQUENT EVENT

On March 8, 1993, Ontario Hydro approved an extensive capital and cost reduction and restructuring program, which is designed to enable Ontario Hydro to seek no rate increase in 1994 and to freeze rates in real terms for the remainder of the decade. Capital expenditures over the next 10 years are expected to be reduced by $10 billion. As part of the program, no commitment will be made at this time to retube the Bruce "A" nuclear reactors, which will continue to be maintained and operated as long as safety requirements permit (see note 11). The retubing option will remain open, subject to a review process prior to any further decisions to undertake retubing. The program is expected to result in staff reductions of approximately 4,500, most of which will occur by the end of 1993. The staff reductions, currently estimated to result in a $500 million charge to operations in 1993, will be achieved mainly through a range of options for voluntary departure. In addition, management has indicated its intention to recommend to the Board of Directors that some or all of the Other deferred costs, amounting to $855 million as at December 31, 1992, be written-off as a charge to operations in 1993 (see note 7).

FIVE-YEAR SUMMARY OF FINANCIAL & OPERATING STATISTICS

millions of dollars	**1992**	1991	1990	1989	1988
REVENUES					
Primary power and energy					
Municipal utilities	**5,281**	4,873	4,373	4,209	3,824
Rural retail customers	**1,568**	1,397	1,297	1,256	1,103
Direct industrial customers	**863**	811	792	790	730
	7,712	7,081	6,462	6,255	5,657
Secondary power and energy	**56**	62	22	91	156
	7,768	7,143	6,484	6,346	5,813
COSTS					
Operation, maintenance and administration	**2,246**	2,037	1,927	1,534	1,354
Fuel used for electric generation	**1,137**	1,122	1,020	1,133	1,133
Power purchased	**186**	151	477	230	57
Provincial government levies	**270**	252	235	177	91
Depreciation	**1,198**	1,136	908	845	811
	5,037	4,698	4,567	3,919	3,446
INCOME BEFORE FINANCING CHARGES	**2,731**	2,445	1,917	2,427	2,367
FINANCING CHARGES					
Gross interest	**3,782**	3,586	3,204	3,016	2,845
Capitalized interest	**(1,231)**	(1,194)	(1,318)	(1,175)	(1,012)
Investment income	**(119)**	(158)	(83)	(144)	(93)
Foreign exchange	**(13)**	7	(15)	31	1
	2,419	2,241	1,788	1,728	1,741
NET INCOME	**312**	204	129	699	626
FINANCIAL POSITION					
Total assets	**46,671**	43,244	39,373	36,277	34,358
Fixed assets	**40,690**	38,170	35,139	32,362	29,975
Long-term debt[1]	**34,034**	32,160	29,378	26,802	25,905
Equity	**6,931**	6,619	6,416	6,287	5,588
CASH FLOWS					
Cash provided from operations	**1,691**	1,381	754	1,705	1,368
Cash provided from financing	**1,811**	2,748	2,889	1,330	1,350
Cash used for investment in fixed assets	**3,375**	3,356	3,592	2,992	2,673
Investment in fixed assets	**3,527**	3,934	3,544	3,095	2,689
FINANCIAL INDICATORS					
Interest coverage[2]	**1.09**	1.06	1.04	1.24	1.23
Debt ratio[3]	**0.841**	0.838	0.829	0.817	0.829
PRIMARY ENERGY SALES[4] *millions of kilowatt-hours*					
Municipal utilities	**91,317**	93,623	92,116	93,715	89,607
Rural retail customers	**18,938**	18,988	19,444	19,767	18,365
Direct industrial customers	**18,094**	18,353	19,315	20,491	20,096
	128,349	130,964	130,875	133,973	128,068
SECONDARY ENERGY SALES[4] *millions of kilowatt-hours*	**1,896**	2,123	577	2,292	5,019

	1992	1991	1990	1989	1988
ENERGY AND DEMAND					
Installed dependable peak capacity *megawatts*[5]	**32,231**	32,333	31,350	30,271	30,333
December primary peak demand *megawatts*	**21,339**	22,933	21,785	23,630	23,012
Primary energy made available *millions of kilowatt-hours*[6]	**134,376**	136,966	136,744	140,770	134,395
NUMBER OF PRIMARY CUSTOMERS[4]					
Municipal utilities	**311**	311	314	315	316
Rural retail customers	**940,501**	925,641	918,368	894,485	863,049
Direct industrial customers	**108**	109	119	116	107
AVERAGE REVENUE[4] *in cents per kilowatt-hour of total energy sales*					
Primary power and energy					
Municipal utilities	**5.783**	5.205	4.747	4.491	4.268
Rural retail customers	**8.884**	7.883	7.352	6.801	6.361
Direct industrial customers	**4.770**	4.419	4.100	3.855	3.633
All primary customers combined	**6.070**	5.459	5.024	4.715	4.453
Secondary power and energy	**2.954**	2.920	3.813	3.970	3.108
All classifications combined	**6.024**	5.419	5.001	4.702	4.402
AVERAGE RATE INCREASES *expressed as a per cent*					
Municipal utilities	**11.8**	8.7	6.1	5.0	4.7
Rural retail customers	**11.8**	8.7	5.3	5.9	4.4
Direct industrial customers	**11.8**	7.8	5.6	6.0	5.2
All primary customers combined	**11.8**	8.6	5.9	5.3	4.7
AVERAGE COST[4,7] *in cents per kilowatt-hour of energy generated*					
Hydraulic					
Operation, maintenance and administration	**.280**	.299	.271	.275	.270
Water rentals	**.317**	.338	.303	.287	.274
Depreciation, debt guarantee fee and financing charges	**.454**	.424	.373	.389	.386
	1.051	1.061	.947	.951	.930
Nuclear					
Operation, maintenance and administration	**1.229**	1.033	1.100	.739	.623
Uranium	**.515**	.502	.490	.458	.453
Depreciation, debt guarantee fee and financing charges	**3.080**	2.756	2.631	2.241	2.078
	4.824	4.291	4.221	3.438	3.154
Fossil					
Operation, maintenance and administration	**.960**	.839	.899	.600	.530
Coal, gas and oil	**2.426**	2.388	2.479	2.217	2.258
Depreciation, debt guarantee fee and financing charges	**1.651**	1.489	1.274	.931	.918
	5.037	4.716	4.652	3.748	3.706

	1992	1991	1990	1989	1988
AVERAGE NUMBER OF EMPLOYEES					
Regular	**28,835**	28,396	26,821	25,147	24,543
Non-regular[8]	**6,004**	7,309	9,653	8,929	7,930

1 Long-term debt includes long-term debt payable within one year.
2 Interest coverage represents net income plus interest on bonds, notes and other debt divided by interest on bonds, notes and other debt.
3 Debt ratio represents debt (bonds and notes payable, short-term notes payable, other long-term debt, accrued fixed asset removal and irradiated fuel disposal costs and bank indebtedness less unamortized foreign exchange gains and losses) divided by debt plus equity.
4 Figures for 1992 are preliminary.
5 Installed dependable peak capacity represents the net output power supplied by all generating units, and includes non-operating reserve facilities: 1992 – 1,554 megawatts; 1991 – 1,546 megawatts; 1990 – 1,551 megawatts; 1989 – 2,109 megawatts; and 1988 – 2,109 megawatts. Also included are net firm power purchase contracts.
6 Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.
7 Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.
8 The majority of non-regular staff are construction trades persons.

CUSTOMERS SERVED BY ONTARIO HYDRO AND ASSOCIATED MUNICIPAL UTILITIES

	1992[1]	1991	1990	1989	1988
TOTAL NUMBER OF CUSTOMERS *in thousands*					
Residential	**3,181**	3,163	3,129	3,064	2,958
Farm	**104**	105	105	105	106
Commercial and industrial	**425**	428	420	408	392
	3,710	3,696	3,654	3,577	3,456
AVERAGE ANNUAL USE *in kilowatt-hours per customer*					
Residential	**11,500**	11,581	11,668	11,856	11,588
Farm	**23,447**	23,945	23,945	24,762	24,795
Commercial and industrial	**198,000**	205,982	212,193	225,103	224,705
AVERAGE REVENUE[2] *in cents per kilowatt-hour*					
Residential	**8.07**	7.23	6.68	6.25	5.99
Farm	**8.19**	7.34	6.80	6.44	6.14
Commercial and industrial	**6.32**	5.70	5.22	4.88	4.62
All customers	**6.87**	6.16	5.67	5.29	5.03

1 Figures for 1992 are preliminary.
2 Includes rural rate assistance.

ONTARIO HYDRO ANNUAL REPORT 1993

STATEMENT OF OPERATIONS

for the year ended December 31 (millions of dollars)

	1993	1992
REVENUES		
Primary power and energy		
Municipal utilities	5,721	5,281
Rural retail customers	1,641	1,568
Direct industrial customers	873	863
	8,235	7,712
Secondary power and energy (note 1)	128	56
	8,363	7,768
COSTS		
Operation, maintenance and administration	2,060	2,246
Fuel used for electric generation	911	1,137
Power purchased	260	186
Provincial government levies (note 2)	286	270
Depreciation (note 3)	1,506	1,198
	5,023	5,037
INCOME BEFORE FINANCING CHARGES	3,340	2,731
Financing charges (note 4)	3,330	2,419
INCOME BEFORE CORPORATE RESTRUCTURING CHARGE AND WRITEOFFS	10	312
Corporate restructuring charge and writeoffs (note 5)	3,614	–
NET INCOME (LOSS)	(3,604)	312

See accompanying summary of significant accounting policies and notes to financial statements.

STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS

for the year ended December 31 (millions of dollars)

	1993	1992
Cash provided from operations		
Net income (loss)	(3,604)	312
Items not requiring cash in the current year		
Depreciation	1,506	1,198
Provision for corporate restructuring and writeoffs	2,916	–
Amortization of foreign exchange gains and losses	41	59
Provision for used nuclear fuel disposal costs	71	42
Other	191	29
	1,121	1,640
Changes in non-cash working capital and long-term accounts payable affecting operations – decrease (note 15)	211	51
Cash provided from operations	1,332	1,691
Cash provided from financing		
Debt for long-term financing		
Issued	3,829	5,863
Retired	(5,468)	(2,882)
	(1,639)	2,981
Redemption of long-term debt, net of reissuances	1,186	(1,197)
Cash received from sale of options	857	–
Changes in cash and cash equivalents		
Bank indebtedness – (decrease)	(20)	(6)
Short-term notes used for cash management – increase	64	33
	44	27
Cash provided from financing	448	1,811
Cash provided from operations and financing	1,780	3,502
Cash provided from (used for) other assets	91	(127)
Cash used for investment in fixed assets (note 15)	1,871	3,375

See accompanying summary of significant accounting policies and notes to financial statements.

NOTES TO FINANCIAL STATEMENTS

1. SECONDARY POWER AND ENERGY

Secondary power and energy revenues include $125 million (1992 – $53 million) from sales of electricity to United States utilities.

2. PROVINCIAL GOVERNMENT LEVIES *millions of dollars*

	1993	1992
Provincial water rentals	112	109
Provincial debt guarantee fee	174	161
	286	270

Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydroelectric generation. The Province of Ontario has legislated that Ontario Hydro pay to the Province an annual debt guarantee fee of one half of one percent on the total debt guaranteed by the Province, outstanding as of the preceding December 31.

3. DEPRECIATION *millions of dollars*

	1993	1992
Depreciation of fixed assets in service	1,369	1,068
Amortization of other deferred costs	39	39
Amortization of deferred demand management costs	22	13
Fixed asset removal costs	158	101
Other removal costs	46	105
	1,634	1,326
Less:		
Depreciation charged to – construction in progress	75	74
– heavy water production	49	50
– fuel for electric generation	1	1
Other	3	3
	128	128
	1,506	1,198

4. FINANCING CHARGES *millions of dollars*

	1993	1992
Interest on bonds, notes and other debt – long-term	3,693	3,636
– short-term	48	22
Interest on accrued fixed asset removal and used nuclear fuel disposal costs	108	124
	3,849	3,782
Less:		
Interest charged to – construction in progress	398	1,167
– heavy water production	48	55
– fuel for electric generation	7	9
Interest earned on investments	74	119
	527	1,350
Interest charged to operations	3,322	2,432
Foreign exchange	8	(13)
	3,330	2,419

5. Corporate Restructuring Charge and Writeoffs *millions of dollars*	1993
Staff reduction programs	624
Staff relocation and reorganization	124
Excess materials and surplus real estate	232
Other deferred costs (note 8)	772
Write-down of nuclear fuel inventories	595
Nuclear Agreement-Payback	410
Excess capacity provision	643
Other restructuring costs	214
	3,614

In March 1993, the Board of Directors of Ontario Hydro approved an extensive cost-reduction and restructuring program, which was designed to enable Ontario Hydro to seek no rate increase in 1994 and to freeze rates in real terms for the remainder of the decade. The restructuring program resulted in a number of charges and writeoffs to net income in 1993.

The charge includes costs directly related to the restructuring including costs associated with a staff reduction program which resulted in the voluntary departure of about 5,000 regular employees. This is in addition to approximately 4,000 contract employees who left during the year and 1,500 regular employees who left under the voluntary programs announced in September 1992. The staff reduction program together with reorganization undertaken as part of the restructuring has also resulted in costs for staff, office and equipment relocations. In addition, the Corporation also identified certain assets, primarily materials and supplies and fixed assets, and specific real estate assets which were no longer needed as a result of the restructuring.

Ontario Hydro has decided to write off and no longer seek recovery of additional amounts which, as a result of past decisions, were being carried on its balance sheet for recovery from customers in future years. Included in the charge are "Other deferred costs" relating to the cancellation of the long-term uranium supply and power purchase contracts (see note 8).

Consistent with the write off of the other deferred costs, the excess of cost over market value in the nuclear fuel inventories and in the future deliveries of fuel associated with the cancelled uranium supply contracts, has been provided for.

The Nuclear Agreement-Payback amount represents accumulated negative payback amounts as a result of the shut-down of Pickering Nuclear Generating Station Units 1 and 2 over the 1983 through 1988 period for replacement of pressure tubes. Due to the uncertainty regarding the future value of this asset, it was being amortized to operations on a straight-line basis. Consistent with the treatment of the other amounts previously deferred and amortized, this amount is being written off.

Ontario Hydro has decided to mothball or shutdown 2,850 megawatts (MW) of surplus generating capacity including two coal fuelled units at Lambton Generating Station, two oil fuelled units at Lennox Generating Station and Unit 2 at Bruce "A" Nuclear Generating Station. This is in addition to four coal fuelled units representing 1,092 MW at Lakeview Generating Station mothballed in January and April of 1993. The amount included in the corporate restructuring charge reflects a provision for the writeoff of the four Lakeview units and Bruce Unit 2, and mothballing costs for the Lennox and Lambton units. The Bruce Unit 2 writeoff includes the Unit's estimated net book value at September 1995, the expected time of shutdown, and estimated decommissioning costs reduced by the Unit's accumulated retubing provision. Also included in the provision are staff reduction costs for all units which will be removed from service and the write off of related construction projects.

6. FIXED ASSETS *millions of dollars*

	1993			1992		
	Fixed Assets in Service	*Accumulated Depreciation*	*Construction in Progress*	*Fixed Assets in Service*	*Accumulated Depreciation*	*Construction in Progress*
Generating stations						
–hydroelectric	2,351	769	589	2,229	739	559
–fossil	4,774	1,900	507	4,453	1,839	783
–nuclear	24,322	3,422	457	17,836	2,969	6,777
Heavy water	4,040	515	1,316	3,308	444	1,334
Transmission and distribution	9,686	2,357	686	9,151	2,158	794
Heavy water production facilities	–	–	–	1,063	612	–
Administration & service facilities	1,805	875	45	1,957	854	61
	46,978	9,838	3,600	39,997	9,615	10,308

Darlington Nuclear Generating Station. The two remaining units at Darlington, Units 3 and 4, were declared in service for commercial operation in February 1993 and June 1993, respectively.

Heavy water. As at December 31, 1993, Ontario Hydro terminated the production of heavy water for its own use, as there was sufficient heavy water on hand to meet future needs of its existing generating stations. This heavy water is shown as construction in progress as at December 31, 1993. Any quantities of heavy water produced in the future will be for sales to external parties. Accordingly, the heavy water production facilities have been fully depreciated and included in the cost of heavy water construction in progress.

7. FUEL FOR ELECTRIC GENERATION *millions of dollars*

		1993	1992
Inventories	–uranium (note 5)	199	725
	–coal	371	525
	–oil	92	95
		662	1,345

8. OTHER DEFERRED COSTS *millions of dollars*

	1993	1992
Bruce Heavy Water Plant "D"	–	37
Wesleyville Generating Station	–	2
Coal purchase agreement	–	17
Denison Mines Limited uranium supply contract	–	242
Rio Algom Limited uranium supply contract	–	448
Manitoba Hydro power purchase contract	–	109
	–	855

Other deferred costs are amounts that the Board of Directors, under its rate setting authority, had determined be deferred and amortized for recovery through electricity rates on a straight-line basis over a specified period of years. In 1993, $39 million and $44 million (1992–$39 million and $73 million) of other deferred costs were charged to depreciation, and fuel used for electric generation, respectively.

In January 1994, as part of the Corporation's restructuring program, the Board of Directors approved a recommendation to no longer seek recovery of these costs through electricity rates. Accordingly, the balance of these costs, $772 million, was written off at December 31, 1993 (see note 5).

9. LONG-TERM DEBT *millions of dollars*

	1993	1992
Bonds and notes payable	33,645	33,994
Other long-term debt	40	40
	33,685	34,034
Less payable within one year	1,837	2,796
	31,848	31,238

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity and by the currency in which they are payable in the following table:

	1993				1992	
Years of Maturity	*Principal Outstanding*			*Weighted Average Interest Rate (percent)*	*Principal Outstanding Total*	*Weighted Average Interest Rate (percent)*
	Canadian	*Foreign*	*Total*			
1993	–	–	–		2,794	
1994	1,192	643	1,835		1,746	
1995	1,855	842	2,697		2,388	
1996	2,309	151	2,460		2,465	
1997	1,056	–	1,056		1,057	
1998	2,591	662	3,253		–	
1–5 years	9,003	2,298	11,301	10.0	10,450	10.6
6–10 years	9,123	795	9,918	10.2	10,762	10.0
11–15 years	2,547	–	2,547	10.0	2,390	9.7
16–20 years	2,191	2,714	4,905	11.0	5,173	11.1
21–25 years	648	–	648	10.0	844	10.5
26 years and over	4,326	–	4,326	10.1	4,375	10.1
	27,838	5,807	33,645	10.2	33,994	10.3

Currency in which payable	1993	1992
Canadian dollars	27,838	27,917
United States dollars	5,673	5,947
Swiss francs	134	130
	33,645	33,994

Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

Bonds and notes payable in United States dollars include $2,052 million (1992 – $4,013 million) of Ontario Hydro bonds held by the Province of Ontario and having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

Option contracts. Ontario Hydro has converted future potential interest savings related to call options embedded in certain of its bonds to cash, by selling offsetting option contracts. The option contracts sold give holders the right to be paid an interest rate equal to the bonds' coupon rate, effective as at the call date. Premiums received from the sale of these contracts are being amortized to income, as a reduction of interest expense, over the remaining terms of the related bond issues. Option contracts with notional principal amounts of Cdn$2,628 million and US$1,043 million were outstanding as at December 31, 1993.

Ontario Hydro has entered into various financial arrangements to hedge a portion of its foreign currency exposure.

9. LONG-TERM DEBT *continued*

Forward exchange contracts. Forward exchange contracts hedging US dollar principal and interest payments totalled US$1,128 million as at December 31, 1993 (1992 – US$1,274 million) and had a weighted average Canadian dollar exchange rate of 1.26 (1992 – 1.26). US$822 million hedge principal and interest payments due in 1994 and the remaining US$306 million hedge payments due over the period 1995 through 1998. In addition, Ontario Hydro has entered into forward exchange contracts to hedge the exposure related to some future US dollar revenues. As at December 31, 1993 such forward exchange contracts amounted to US$185 million and had a weighted average Canadian dollar exchange rate of 1.35. US$3 million of these contracts hedge revenues expected in 1994 and the remaining US$182 million hedge revenues expected over the period 1995 through 1998.

Foreign currency swap contracts. Foreign currency swap contracts to hedge US$777 million and Swiss franc 239 million of principal and interest payments into Canadian dollars were outstanding as at December 31, 1993 (1992 – US$837 million and Swiss franc 250 million). Of this, US$60 million and Swiss franc 11 million are due in 1994, and US$717 million and Swiss franc 228 million are due over the period 1995 to 2001.

10. BANK INDEBTEDNESS

Short-term bank lines of credit are available to Ontario Hydro in the amount of $600 million (1992 – $600 million), of which $575 million was utilized at year end (1992 – $590 million). The lines of credit are unsecured and bear interest at less than the prime rate.

11. SHORT-TERM NOTES PAYABLE *millions of dollars*

	1993	1992
Short-term notes used for cash management	191	127
Short-term notes used for long-term financing	918	771
	1,109	898

Certain bond issues were called and refinanced at favourable interest rates by issuing short-term notes. Financial arrangements were also entered into so as to achieve a fixed interest rate on most of the refinanced issues.

12. ACCRUED FIXED ASSET REMOVAL & USED NUCLEAR FUEL DISPOSAL COSTS *millions of dollars*

	1993	1992
Accrued fixed asset removal costs		
– accrued decommissioning costs	588	447
– accrued fuel channel removal costs	394	374
	982	821
Accrued used nuclear fuel disposal costs	791	696
	1,773	1,517

Fixed asset removal costs. Fixed asset removal costs are the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives, and the costs of removing certain fuel channels which are expected to be replaced during the life of the nuclear reactors. The significant assumptions used in estimating fixed asset removal costs were:

- decommissioning of nuclear generating stations in the 2042 to 2062 period on a deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- dismantlement of Bruce Heavy Water Plants "A", "B" and "D" in the 1994 to 2005 period;
- interest rates through to 2065 ranging from 9% to 10% (1992 – 9% to 11%);
- escalation rates through to 2065 ranging from 3% to 7% (1992 – 4% to 7%); and

12. Accrued Fixed Asset Removal & Used Nuclear Fuel Disposal Costs *continued*

- removal of fuel channels in nuclear generating stations during the following periods (1992 comparative in brackets)

Bruce "A"	1994 to 2007 (1993 to 1999)
Pickering "B"	2009 to 2016 (2012 to 2017)
Bruce "B"	2011 to 2019 (2014 to 2019)
Darlington	2016 to 2024 (2019 to 2024).

Because of possible changes to the above factors and the methods used for decommissioning and fuel channel removal, these costs are subject to revision. In 1993, as part of the cost reduction and restructuring program, the commitment to retube Bruce "A" Nuclear Generating Station was suspended. In February 1994, Ontario Hydro decided to shutdown Unit 2 at Bruce "A" Nuclear Generating Station in 1995. The accumulated fixed asset removal provision relating to the retubing of Unit 2 was used to reduce the amount relating to the shutdown of Unit 2 charged to the corporate restructuring provision.

Used nuclear fuel disposal costs. The significant assumptions used in estimating the future used nuclear fuel disposal costs were:

- an in-service date of the year 2025 (1992 – 2025) for used nuclear fuel disposal facilities;
- a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 9% to 10% (1992 – 9% to 11%); and
- escalation rates through to the disposal date ranging from 3% to 7% (1992 – 4% to 7%).

Because of the uncertainties associated with the technology of disposal and the above factors, these costs are subject to change.

13. Contingencies

Manitoba Hydro

In December 1992, due to a projected surplus in generating capacity, Ontario Hydro exercised its right to terminate its long-term power purchase contract with Manitoba Hydro. In Manitoba Hydro's certificate of costs for reimbursement, an amount for $49 million was claimed for costs incurred by Manitoba Hydro prior to entering into the contract with Ontario Hydro on December 7, 1989. Ontario Hydro is of the opinion that costs incurred by Manitoba Hydro before December 7, 1989 are not reimbursable by Ontario Hydro under the contract. As well, based on a review of the certificate of costs, it appears that the total cost claimed by Manitoba Hydro may have been overstated. Ontario Hydro has commenced an action against Manitoba Hydro for a declaration that Ontario Hydro is not obliged to pay costs incurred prior to entering into the contract and for a further judgement against Manitoba Hydro requiring the repayment of amounts which were improperly claimed by Manitoba Hydro and paid by Ontario Hydro under the contract. At this time, the outcome of the action is not determinable, and as such, no provision has been accrued in Ontario Hydro's financial statements with respect to any amounts in dispute.

14. Retained Earnings *millions of dollars*	1993	1992
Balance at beginning of year	6,931	6,619
Net income (loss)	(3,604)	312
Net refunds on annexation by municipalities	(2)	–
Balance at end of year	3,325	6,931

In 1993, Ontario Hydro consolidated and reclassified its three equity accounts into one retained earnings account. The accounts that were reclassified include the accumulated debt retirement appropriation, the reserve for stabilization of rates and contingencies, and contributions from the Province of Ontario as assistance for rural construction.

15. STATEMENT OF SOURCE OF CASH USED FOR INVESTMENT IN FIXED ASSETS *millions of dollars*

Cash provided from financing represents the amount of cash provided from the issuance of long-term debt and the issuance of short-term notes used for long-term financing, less the amount of cash used to retire or redeem long-term debt, and the effects of changes in cash and cash equivalents. Cash and cash equivalents are defined to be cash and short-term investments less bank indebtedness and short-term notes used for cash management.

The changes in non-cash working capital and long-term accounts payable affecting operations consisted of the following:

	1993	1992
Accounts receivable – (increase)	(175)	(113)
Fuel for electric generation – decrease (increase)	286	(3)
Materials and supplies – (increase) decrease	(7)	51
Accounts payable and accrued charges – increase	43	188
Accrued interest – increase	28	6
Long-term accounts payable and accrued charges – increase (decrease)	36	(78)
	211	51

The reconciliation of the change in fixed assets during the year with the investment in fixed assets and cash used for investment in fixed assets is shown below:

	1993	1992
Change in fixed assets	50	2,520
Depreciation of fixed assets in service	1,369	1,068
Depreciation charged to heavy water production and construction in progress	(124)	(124)
Net book value of fixed assets sold or retired	1,001	63
Investment in fixed assets	2,296	3,527
Changes in accounts payable and accrued charges affecting investment in fixed assets – (increase)	(425)	(152)
Cash used for investment in fixed assets	1,871	3,375

16. BENEFIT PLANS

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan and the long-term disability plan.

Pension plan. Regular pension costs for 1993 were $161 million (1992 – $161 million). In 1993, $106 million (1992 – $106 million) of the pension costs were charged to operations and $55 million (1992 – $55 million) were capitalized. In addition, included in the corporate restructuring charge are costs of $327 million associated with the voluntary staff reduction program. The pension costs for 1993 were actuarially determined for accounting purposes using the following significant assumptions which take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits – 6.50% (1992 – 7.00%);
- rate used to estimate interest cost – 6.50% (1992 – 7.00%);
- rate used to estimate return on investments – 8.75% (1992 – 9.00%);
- salary schedule escalation rate – 3.50% (1992 – 4.00%);
- average long-term rate used to estimate improvements in pension benefits to partially offset the effect of increase in cost of living – 2.44% (1992 – 2.81%); and
- average remaining service period of employees – 17 years (1992 – 17 years).

16. BENEFIT PLANS *continued*

Based on these assumptions, the actuarial present value of the accrued pension benefits is estimated to be $7,201 million as at December 31, 1993 (1992 – $6,386 million), and the pension plan assets available for these benefits were $6,317 million (1992 – $5,748 million) based on a five-year market value average.

Deferred pension costs on the statement of financial position represent the cumulative difference between the funding contributions, including special payments, and pension costs. As at December 31, 1993, the deferred pension costs amounted to $208 million (1992 – $535 million) and primarily reflect special payments made in 1990 and 1991 relating to past service benefit improvements offset by costs associated with the 1993 voluntary staff reduction program. The costs of pension benefit improvements funded by the special payments are being amortized as a charge to pension costs over the average remaining service period of employees.

Group life insurance plan. Ontario Hydro paid $5 million in premiums for basic insurance coverage for employees. Premiums for additional coverage, if requested, are paid for by the employees.

Group health care plan. Ontario Hydro provides a group health care plan to its employees. In 1993, the cost of providing these benefits was $63 million (1992 – $51 million).

Other post-employment benefits. In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as the benefits are paid. In 1993, the cost of providing these benefits was $15 million (1992 – $16 million).

17. RESEARCH AND DEVELOPMENT

In 1993, approximately $129 million of research and development costs were charged to operations and $42 million were capitalized (1992 – $134 million and $49 million, respectively).

18. DENISON MINES LIMITED

In April 1991, Ontario Hydro notified Denison Mines Limited (Denison), pursuant to the provisions in the contract, that the long-term uranium supply contract would be terminated effective January 1, 1993. In Denison's 1991 and 1992 base price statements for the cost of production of uranium supplied to Ontario Hydro, Denison included significant amounts for depreciation and other costs, which Denison claimed resulted from a revision to the estimated life of its Elliot Lake uranium mine as a consequence of the contract termination by Ontario Hydro and Denison's decision to close the mine. The position asserted by Denison would have resulted in substantial additional charges related to uranium deliveries in 1991 and 1992. Ontario Hydro rejected this position as not being in accordance with the provisions of the supply contract and the dispute was submitted to arbitration. The arbitration tribunal unanimously dismissed the majority of the over $350 million claim by Denison against Ontario Hydro and requires Ontario Hydro to pay approximately $31 million, plus interest, related to Denison's severance payments and post-employment benefits. The amount payable to Denison has been provided for as part of the corporate restructuring charge and writeoffs against net income in 1993 consistent with the treatment of other amounts relating to the cancellation of the long-term uranium supply contracts.

19. COMPARATIVE FIGURES

Certain of the 1992 comparative figures in the financial statements have been reclassified to conform with the 1993 financial statement presentation.

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS *millions of dollars*

Revenues	1993	1992	1991	1990	1989
Primary power and energy					
Municipal utilities	5,721	5,281	4,873	4,373	4,209
Rural retail customers	1,641	1,568	1,397	1,297	1,256
Direct industrial customers	873	863	811	792	790
	8,235	7,712	7,081	6,462	6,255
Secondary power and energy	128	56	62	22	91
	8,363	7,768	7,143	6,484	6,346
Costs					
Operation, maintenance and administration	2,060	2,246	2,037	1,927	1,534
Fuel used for electric generation	911	1,137	1,122	1,020	1,133
Power purchased	260	186	151	477	230
Provincial government levies	286	270	252	235	177
Depreciation	1,506	1,198	1,136	908	845
	5,023	5,037	4,698	4,567	3,919
Income before financing charges	3,340	2,731	2,445	1,917	2,427
Financing charges					
Gross interest	3,849	3,782	3,586	3,204	3,016
Capitalized interest	(453)	(1,231)	(1,194)	(1,318)	(1,175)
Investment income	(74)	(119)	(158)	(83)	(144)
Foreign exchange	8	(13)	7	(15)	31
	3,330	2,419	2,241	1,788	1,728
Income before restructuring charge	10	312	204	129	699
Corporate restructuring charge and writeoffs	3,614	–	–	–	–
Net income (loss)	(3,604)	312	204	129	699
Financial position					
Total assets	44,706	46,671	43,244	39,373	36,277
Fixed assets	40,740	40,690	38,170	35,139	32,362
Long-term debt[1]	33,685	34,034	32,160	29,378	26,802
Equity	3,325	6,931	6,619	6,416	6,287
Cash flows					
Cash provided from operations	1,332	1,691	1,381	754	1,705
Cash provided from financing	448	1,811	2,748	2,889	1,330
Cash used for investment in fixed assets	1,871	3,375	3,356	3,592	2,992
Investment in fixed assets	2,296	3,527	3,934	3,544	3,095
Financial indicators					
Interest coverage (operating income)[2]	1.00	1.09	1.06	1.04	1.24
Interest coverage (net loss)[2]	0.04	–	–	–	–
Debt ratio[3]	0.918	0.841	0.838	0.829	0.817

	1993	1992	1991	1990	1989
Primary energy sales[4] *millions of kilowatt-hours*					
Municipal utilities	92,044	91,317	93,623	92,116	93,715
Rural retail customers	18,512	18,938	18,988	19,444	19,767
Direct industrial customers	17,221	18,094	18,353	19,315	20,491
	127,777	128,349	130,964	130,875	133,973
Secondary energy sales[4] *millions of kilowatt-hours*	4,807	1,896	2,123	577	2,292
Energy and demand					
Installed dependable peak capacity *megawatts*[5]	33,793	32,231	32,333	31,350	30,271
December primary peak demand *megawatts*	20,506	21,339	22,933	21,785	23,630
Primary energy made available *millions of kilowatt-hours*[6]	133,769	134,376	136,966	136,744	140,770
Number of primary customers[4]					
Municipal utilities	309	311	311	314	315
Rural retail customers	944,622	940,617	925,641	918,368	894,485
Direct industrial customers	104	107	109	119	116
Average revenue[4] *in cents per kilowatt-hour of total energy sales*					
Primary power and energy					
Municipal utilities	6.216	5.783	5.205	4.747	4.491
Rural retail customers	9.265	8.884	7.883	7.352	6.801
Direct industrial customers	5.069	4.770	4.419	4.100	3.855
All primary customers combined	6.485	6.070	5.459	5.024	4.715
Secondary power and energy	2.663	2.954	2.920	3.813	3.970
All classifications combined	6.346	6.024	5.419	5.001	4.702
Average rate increases *expressed as a percent*					
Municipal utilities	8.2	11.8	8.7	6.1	5.0
Rural retail customers	6.5	11.8	8.7	5.3	5.9
Direct industrial customers	8.2	11.8	7.8	5.6	6.0
All primary customers combined	7.9	11.8	8.6	5.9	5.3
Average cost[4,7] *in cents per kilowatt-hour of energy generated*					
Hydroelectric					
Operation, maintenance and administration	.277	.280	.299	.271	.275
Water rentals	.330	.317	.338	.303	.287
Depreciation, debt guarantee fee and financing charges	.488	.454	.424	.373	.389
	1.095	1.051	1.061	.947	.951
Nuclear					
Operation, maintenance and administration	1.017	1.229	1.033	1.100	.739
Uranium	.514	.515	.502	.490	.458
Depreciation, debt guarantee fee and financing charges	3.910	3.080	2.756	2.631	2.241
	5.441	4.824	4.291	4.221	3.438

	1993	1992	1991	1990	1989
Fossil					
Operation, maintenance and administration	1.303	.960	.839	.899	.600
Coal, gas and oil	2.515	2.426	2.388	2.479	2.217
Depreciation, debt guarantee fee and financing charges	3.011	1.645	1.489	1.274	.931
	6.829	5.031	4.716	4.652	3.748
Average number of employees					
Regular	26,442	28,835	28,396	26,821	25,147
Non-regular[8]	3,331	6,004	7,309	9,653	8,929

1. Long-term debt includes long-term debt payable within one year.
2. Interest coverage represents net income plus interest on bonds, notes, and other debt divided by interest on bonds, notes and other debt.
3. Debt ratio represents debt (bonds and notes payable, short-term notes payable, other long-term debt, unamortized option premiums, accrued fixed asset removal and used nuclear fuel disposal costs and bank indebtedness less unamortized foreign exchange gains and losses) divided by debt plus equity.
4. Figures for 1993 are preliminary.
5. Installed dependable peak capacity represents the net output power supplied by all generating units, and includes non-operating reserve facilities: 1993–2,686 MW; 1992–1,554 MW; 1991–1,546 MW; 1990–1,551 MW; and 1989–2,109 MW. Also included are net firm power purchase contracts.
6. Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.
7. Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.
8. The majority of non-regular staff are construction trades persons.

CUSTOMERS SERVED BY ONTARIO HYDRO AND ASSOCIATED MUNICIPAL UTILITIES

	1993[1]	1992	1991	1990	1989
Total number of customers *in thousands*					
Residential	3,207	3,205	3,163	3,129	3,064
Farm	103	104	105	105	105
Commercial and industrial	431	430	428	420	408
	3,741	3,739	3,696	3,654	3,577
Average annual use *in kilowatt-hours per customer*					
Residential	11,000	11,024	11,581	11,668	11,856
Farm	23,564	23,496	23,945	23,945	24,762
Commercial and industrial	198,000	201,112	205,982	212,193	225,103
Average revenue[2] *in cents per kilowatt-hour*					
Residential	8.69	8.12	7.23	6.68	6.25
Farm	9.02	8.19	7.34	6.80	6.44
Commercial and industrial	6.75	6.31	5.70	5.22	4.88
All customers	7.35	6.86	6.16	5.67	5.29

1. Figures for 1993 are preliminary.
2. Includes rural rate assistance.

ONTARIO HYDRO 1994 ANNUAL REPORT

MISSION STATEMENT

To make Ontario Hydro a ader in **energy efficiency** and **sustainable development,** and to provide its customers with **safe and reliable** energy services at **competitive prices.**

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EB-2016-0152
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Consolidated Statement of Operations

for the year ended December 31 (millions of dollars)

REVENUES	1994	1993
Primary power and energy		
Municipal utilities	5,829	5,721
Retail customers	1,688	1,641
Direct industrial customers	866	873
	8,383	8,235
Secondary power and energy (note 2)	349	128
	8,732	8,363
COSTS		
Operation, maintenance and administration	1,705	2,060
Fuel used for electric generation	577	911
Power purchased	316	260
Provincial government levies (note 3)	284	286
Depreciation and amortization (note 4)	1,593	1,506
	4,475	5,023
INCOME BEFORE FINANCING CHARGES	4,257	3,340
Financing charges (note 5)	3,402	3,330
INCOME BEFORE CORPORATE RESTRUCTURING CHARGE AND WRITEOFFS	855	10
Corporate restructuring charge and writeoffs (note 6)	268	3,614
NET INCOME (LOSS)	587	(3,604)

See accompanying notes to financial statements.

Consolidated Statement of Financial Position

as at December 31 (millions of dollars)

ASSETS	1994	1993
Fixed assets (note 7)		
Fixed assets in service	49,495	46,978
Less accumulated depreciation	11,146	9,838
	38,349	37,140
Construction in progress	1,468	3,600
	39,817	40,740
Current assets		
Accounts receivable	1,258	1,207
Fuel for electric generation (note 8)	519	662
Materials and supplies, at cost	281	283
	2,058	2,152
Other assets		
Deferred debt costs	1,046	828
Deferred pension costs (note 17)	169	208
Deferred demand management costs, net of accumulated amortization	396	360
Long-term accounts receivable and other assets	599	418
	2,210	1,814
	44,085	44,706

See accompanying notes to financial statements.

Liabilities	1994	1993
Long-term debt (note 9)	30,202	31,848
Current liabilities		
Bank indebtedness (note 10)	647	615
Accounts payable and accrued charges	1,242	1,736
Short-term notes payable (note 11)	1,129	1,109
Accrued interest	891	979
Long-term debt payable within one year (note 9)	2,765	1,837
	6,674	6,276
Other liabilities		
Unamortized swaption premiums (note 12)	696	853
Long-term accounts payable and accrued charges	553	631
Accrued fixed asset removal and used nuclear fuel disposal costs (note 13)	2,048	1,773
	3,297	3,257
Contingencies (note 14)		
Equity		
Retained earnings (note 15)	3,912	3,325
	44,085	44,706

On behalf of the Board,

Chairman, Board of Directors

President & Chief Executive Officer

Toronto, Canada,
March 13, 1995

Consolidated Statement of Changes in Cash Position

for the year ended December 31 (millions of dollars)

	1994	1993
Operating activities		
Net income (loss)	587	(3,604)
Adjust for non-cash items		
Depreciation and amortization	1,593	1,506
Provision for corporate restructuring and writeoffs	33	2,916
Amortization of foreign exchange gains and losses	52	41
Provision for used nuclear fuel disposal costs	93	71
Other	(111)	191
	2,247	1,121
Change in non-cash balances related to operations (note 16)	(20)	211
	2,227	1,332
Financing activities		
Debt for long-term financing		
Issued	2,737	3,829
Retired	(3,700)	(5,468)
	(963)	(1,639)
Redemption of debt for long-term financing, net of re-issuances	(210)	1,186
Cash (paid on settlement) received from sale of swaptions	(72)	857
	(1,245)	404
Investing activities		
Fixed assets	(997)	(1,871)
Other assets	(91)	91
	(1,088)	(1,780)
Change in cash position during the year	(106)	(44)
Cash position at beginning of year	(806)	(762)
Cash position at end of year (note 16)	(912)	(806)

See accompanying notes to financial statements.

Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in Canada, applied on a basis consistent with that of the preceding year. The significant accounting policies followed by Ontario Hydro are described below.

Rate setting

Ontario Hydro has broad powers to generate, supply and deliver electric power throughout the Province of Ontario. The Corporation operates under the Power Corporation Act and is subject to the provisions of the Ontario Energy Board Act.

Under the provisions of the Power Corporation Act, the price payable by municipal and other customers for power is the cost of supplying the power. Such cost is defined in the Act to include the cost of operating and maintaining the system, the cost of energy conservation programs, depreciation, interest, and the annual amounts for debt retirement and stabilization of rates and contingencies. The annual amounts for debt retirement and stabilization of rates and contingencies are accounted for as net income. In 1993, Ontario Hydro consolidated the accumulated amounts collected for debt retirement and stabilization of rates and contingencies into one retained earnings account.

Under the provisions of the Ontario Energy Board Act, a public hearing before the Ontario Energy Board is required to review any changes in electricity rates proposed by Ontario Hydro which affect its municipal utilities, direct industrial customers, or, if the Minister of Environment and Energy so directs, retail customers. The Ontario Energy Board then submits its recommendations to the Minister of Environment and Energy. After considering the recommendations of the Ontario Energy Board, Ontario Hydro's Board of Directors, under the authority of the Power Corporation Act, establishes the electricity rates to be charged to customers.

The Board of Directors may specify that an amount related to an item be included in electricity rates of a period which differs from the period in which it would be recognized under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment. If so, the accounting treatment given the item is the same as its treatment for rate-setting purposes. This authority of the Board of Directors may be used in respect of a specific transaction or an accounting policy.

Ontario Hydro's accounting policies relating to discounts and premiums arising from the acquisition of debt prior to maturity and foreign exchange gains and losses on early retirement of debt including short-term replacement financing denominated in United States dollars reflect the rate-setting treatment of these items as specified by the Board of Directors. Under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment these amounts would be included as gains or losses of the current period. The Board of Directors has also used its rate-setting authority to specify that costs of the rehabilitation program for steam generators at Pickering "A" and "B" and Bruce "A" Nuclear Generating Stations shall be deferred for recovery in future periods. Under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment these costs would be expensed as incurred.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

Consolidation

The consolidated financial statements include the financial statements of Ontario Hydro and its wholly-owned subsidiary Ontario Hydro International Inc. (OHI Inc.). OHI Inc. was incorporated under the Ontario Business Corporations Act and was established as a subsidiary of Ontario Hydro in September, 1993.

Fixed assets

Fixed assets in service include operating facilities and non-operating reserve facilities, and heavy water held for use in nuclear generating stations. Construction in progress includes fixed assets under construction.

Fixed assets are capitalized at cost which comprises material, labour, engineering costs, overheads, depreciation on service equipment, interest applicable to capital construction activities, and for new facilities, the costs of training initial operating staff. In the case of generating facilities, the cost also includes the net cost of commissioning which comprises the cost of start-up less the value attributed to energy produced by generation facilities during their commissioning period. For multi-unit facilities, a proportionate share of the cost of common facilities is placed in service with each major operating unit. The cost of heavy water comprises the direct cost of production and applicable overheads, as well as interest and depreciation on the heavy water production facilities and the estimated removal costs of these facilities. Leases which transfer the benefits and risks of ownership of assets to Ontario Hydro are capitalized.

Interest is capitalized on construction in progress at rates (1994 - 10.2 per cent, 1993 - 9.8 per cent representing the average cost of long-term funds borrowed in the years in which expenditures have been made for fixed assets under construction) which approximate the average cost of all long-term funds borrowed. If the construction period of a project is extended and the construction activities are continued, interest is capitalized during the period of extension provided that the project has a reasonable expectation of being completed.

If a project is cancelled or deferred indefinitely with a low probability of resuming construction, all costs, including the costs of cancellation, are written off to operations.

If fixed assets are removed from operations and mothballed for future use, classified as non-operating reserve facilities, the costs of mothballing are charged to operations.

Depreciation

The capital costs of fixed assets in service are depreciated on a straight-line basis, with the exception of heavy water held to replace losses occurring during the operation of Ontario Hydro's nuclear generating stations. Heavy water held for this purpose is depreciated on a sinking fund basis over the period through to the first year heavy water from an out-of-service nuclear station is estimated to be available for replacement purposes. Depreciation rates for the various classes of assets are based on their estimated service lives. Major components of fossil and nuclear generating stations are depreciated over the lesser of the service life expectancy of the major component or the remaining service life of the associated generating station; for hydroelectric generating stations, major components are depreciated over the service life expectancy of the component, ranging from 25 to 100 years. The estimated service lives of assets in the major classes are:

Generating stations	– fossil – nuclear	– 40 years – 40 years
Heavy water	– in nuclear generating stations	– over the period ending in the year 2040
	– held for use in nuclear generating stations	– over the period ending in the year 2011
Transmission and distribution facilities		– 10 to 100 years
Administration and service facilities		– 5 to 65 years

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES *(continued)*

In accordance with group depreciation practices, for normal retirements the cost of fixed assets retired is charged to accumulated depreciation with no gain or loss reflected in operations. However, gains and losses on sales of fixed assets and losses on premature retirements are charged to operations in the year incurred as adjustments to depreciation expense.

When the costs of removal less residual value on retirements of fixed assets can be reasonably estimated and are significant, provisions for these costs, except for those related to heavy water production facilities, are charged to depreciation expense on an annuity basis over the remaining service life of the related fixed assets. Removal costs that are provided for include the estimated costs of decommissioning nuclear and fossil stations and heavy water production facilities, and the estimated costs of removing certain nuclear reactor fuel channels. Other removal costs are charged to depreciation expense as incurred.

The estimated service lives of fixed assets and the significant assumptions underlying the estimates of fixed asset removal costs are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in electricity prices.

Non-operating reserve facilities are amortized so that any estimated loss in value is charged to depreciation expense on a straight-line basis over their expected non-operating period.

Heavy water sales

Ontario Hydro has produced sufficient quantities of heavy water to meet future needs of its existing nuclear generating stations and is now producing heavy water for sales to external parties. Revenues from external sales contracts requiring the production of heavy water far in advance of delivery dates are recognized on a percentage-of-completion basis and revenues from all other heavy water sales are recognized at the point of sale. Resulting profits or losses are credited or charged to operations in the year incurred.

Fuel for electric generation

Fuel used for electric generation comprises the average inventory costs of fuel consumed, the value attributed to commissioning energy produced, and provisions for disposal of nuclear fuel used during the period. The inventory cost of fuel consumed comprises fuel purchases, transportation and handling costs.

The value attributed to commissioning energy produced during the period represents the incremental operating and fuel costs of producing the same quantity of energy at generating units displaced because of the commissioning activity. The costs for disposal of nuclear fuel used in each period are charged to operations based on estimated future expenditures and interest accumulating to the estimated date of disposal. Estimates of expenditures, interest and escalation rates, and the date of disposal are subject to periodic review. Adjustments resulting from changes in estimates are charged to operations on an annuity basis over the period from the year the changes can first be reflected in electricity prices to the estimated in-service date of the disposal facility.

Foreign currency translation

Current monetary assets and liabilities in foreign currencies are translated to Canadian currency at year-end rates of exchange and the resultant exchange gains or losses are credited or charged to operations. Long-term debt payable in foreign currencies is translated to Canadian currency at year-end rates of exchange. Resulting unrealized exchange gains or losses are deferred and included in deferred debt costs, and are amortized to operations on an annuity basis over the remaining life of the related debt.

Foreign exchange gains or losses on hedges of long-term debt payable in foreign currencies are deferred and included in deferred debt costs. The deferred gains or losses on hedges are amortized to operations in the periods the hedges provide benefit.

Foreign exchange gains or losses on early redemption of long-term debt, including subsequent gains and losses on short-term replacement financing, are deferred and included in deferred debt costs if the exposure in the foreign currency related to the redeemed debt is continued by refinancing the redeemed debt in the same currency. These deferred

1. Summary of significant accounting policies *(continued)*

gains or losses are amortized on an annuity basis over the period to the original maturity date of the redeemed debt. If the foreign currency exposure is reduced as a result of the early redemption of debt, the resulting foreign exchange gains or losses related to the redeemed debt are credited or charged to operations.

Deferred debt costs

Deferred debt costs include the unamortized amounts related to unrealized foreign exchange gains or losses resulting from the translation of foreign currency long-term debt; deferred foreign exchange gains or losses on hedges; deferred foreign exchange gains or losses on the early redemption of long-term debt; discounts or premiums arising from the issuance of debt or the acquisition of debt prior to maturity; discounts or premiums accrued on foreign currency hedges; and net unamortized premiums on settled, exercised or expired swaption contracts.

Discounts or premiums arising from the issuance of debt are amortized over the period to maturity of the debt. Discounts or premiums on debt acquired prior to the date of maturity are amortized over the period from the acquisition date to the original maturity date of the debt. Discounts or premiums on foreign currency hedges are credited or charged to operations over the terms of the individual hedges. Net unamortized premiums on settled, exercised or expired swaption contracts are amortized over the period from the settlement, exercise or expiry date to the original maturity date of the related debt.

Demand management

Demand management activities undertaken by Ontario Hydro encourage customers to conserve or use electricity more efficiently. Demand management costs that have reasonably assured and specifically identifiable future benefits to Ontario Hydro are deferred and amortized to operations on a straight-line basis over the periods that benefit. All other costs are charged to operations as incurred. The benefit periods of deferred demand management costs are subject to periodic review. Any changes arising out of such a review are implemented on a remaining benefit period basis from the year the changes can first be reflected in electricity prices.

Pension plan

The pension plan is a contributory, defined benefit plan covering all regular employees of Ontario Hydro. Pension costs for accounting purposes are actuarially determined using the projected benefit method prorated on services and based on assumptions that reflect management's best estimate of the effect of future events on the actuarial present value of accrued pension benefits. Pension plan assets are valued using current market values and pension plan adjustments are amortized on a straight-line basis over the expected average remaining period of service of the employees covered by the Ontario Hydro pension plan.

Research and development

Research and development costs are charged to operations in the year incurred, except for those related directly to the design or construction of a specific capital facility which are capitalized as part of the cost of the facility.

2. Secondary power and energy

Secondary power and energy revenues include $345 million (1993 - $125 million) from sales of electricity to United States utilities.

3. Provincial government levies *(millions of dollars)*

	1994	1993
Provincial water rentals	110	112
Provincial debt guarantee fee	174	174
	284	286

3. Provincial government levies *(continued)*

Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydroelectric generation. The Province of Ontario has legislated that Ontario Hydro pay to the Province an annual debt guarantee fee of one half of one percent on the total debt guaranteed by the Province, outstanding as of the preceding December 31.

4. Depreciation and amortization *(millions of dollars)*

		1994	1993
Depreciation of fixed assets in service		1,421	1,369
Amortization of other deferred costs		-	39
Amortization of deferred demand management costs		31	22
Fixed asset removal costs		137	158
Other removal costs		13	46
		1,602	1,634
Less:			
Depreciation charged to	– construction in progress	8	75
	– heavy water production	–	49
	– fuel for electric generation	–	1
Other		1	3
		9	128
		1,593	1,506

Depreciation of fixed assets in service for 1994 includes $28 million relating to the depreciation of heavy water held to replace losses occurring during the operation of Ontario Hydro's nuclear generating stations. Prior to 1994, operation, maintenance and administration costs included a charge for actual quantities of heavy water used for this purpose (1993 - $47 million). Following the termination in 1993 of heavy water production for Ontario Hydro's use, the accounting for the cost of heavy water held for use in nuclear generating stations was changed to ensure the cost is fully depreciated once additional heavy water becomes available from an out-of-service nuclear station.

5. Financing charges *(millions of dollars)*

		1994	1993
Interest on bonds, notes and other debt	– long-term	3,331	3,693
	– short-term	101	48
Interest on accrued fixed asset removal and used nuclear fuel disposal costs		112	108
		3,544	3,849
Less:			
Interest charged to	– construction in progress	104	398
	– heavy water production	–	48
	– fuel for electric generation	6	7
Interest earned on investments		74	74
		184	527
Interest charged to operations		3,360	3,322
Foreign exchange		42	8
		3,402	3,330

6. CORPORATE RESTRUCTURING CHARGE AND WRITEOFFS *(millions of dollars)*

	1994	1993
Staff reduction and relocation costs	268	748
Asset write-offs and write-downs	–	2,009
Excess capacity provision	–	643
Other restructuring costs	–	214
	268	3,614

In March 1993, the Board of Directors of Ontario Hydro approved an extensive cost-reduction and restructuring program, which was designed to enable Ontario Hydro to seek no rate increase in 1994 and to freeze rates in real terms for the remainder of the decade. The restructuring program resulted in charges and writeoffs to net income in 1993 and 1994.

The 1993 charge includes costs associated with voluntary staff reductions of about 5,000 regular employees. As part of the 1993 restructuring, Ontario Hydro also decided to write off and no longer seek recovery of additional amounts which, as a result of past decisions, were being carried on its balance sheet for recovery from customers in future years. The 1993 corporate restructuring charge also reflects a provision for the shutdown and mothballing costs of certain generating units due to the surplus generating capacity.

In 1994 through a review of the restructuring program initiated in 1993 and the business planning process, the Corporation identified the need for additional staff reductions of approximately 2,400 positions. A Special Separation Plan was approved by the Board of Directors in December 1994 to attract as many voluntary staff departures as possible, with the balance to be achieved through involuntary measures, if required. A provision of $268 million was charged against income for 1994 to cover the estimated cost of the voluntary and involuntary staff reductions as well as costs related to surplus assets, lease cancellations and relocation costs related to the staff reductions.

7. FIXED ASSETS *(millions of dollars)*

		1994		
		Fixed Assets in Service	Accumulated Depreciation	Construction in Progress
Generating stations	– hydroelectric	2,405	800	601
	– fossil	5,344	2,083	36
	– nuclear	24,375	4,141	486
Heavy water		5,343	645	–
Transmission and distribution		10,180	2,553	342
Administration and service facilities		1,848	924	3
		49,495	11,146	1,468

		1993		
		Fixed Assets in Service	Accumulated Depreciation	Construction in Progress
Generating stations	– hydroelectric	2,351	769	589
	– fossil	4,774	1,900	507
	– nuclear	24,322	3,422	457
Heavy water		4,040	515	1,316
Transmission and distribution		9,686	2,357	686
Administration and service facilities		1,805	875	45
		46,978	9,838	3,600

7. FIXED ASSETS *(continued)*

Nuclear steam generator rehabilitation costs: Ontario Hydro has undertaken a major program to rehabilitate steam generators at Pickering "A" and "B" and Bruce "A" Nuclear Generating Stations. Costs of the program, which will continue until 1998, have been deferred and will be amortized over the remaining service lives of the individual generators commencing as each generator is returned to service. Deferred nuclear steam generator rehabilitation costs of $71 million are included in nuclear generating station construction in progress as at December 31, 1994.

8. FUEL FOR ELECTRIC GENERATION *(millions of dollars)*		1994	1993
Inventories	– uranium	135	199
	– coal	319	371
	– oil	65	92
		519	662

9. LONG-TERM DEBT *(millions of dollars)*	1994	1993
Bonds and notes payable	32,928	33,645
Other long-term debt	39	40
	32,967	33,685
Less payable within one year	2,765	1,837
	30,202	31,848

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity in the following table:

	1994				1993	
	Principal Outstanding					
Years of Maturity	Canadian	Foreign	Total	Weighted Average Interest Rate (percent)	Principal Outstanding Total	Weighted Average Interest Rate (percent)
1994	–	–	–		1,835	
1995	1,870	892	2,762		2,697	
1996	2,566	160	2,726		2,460	
1997	1,000	491	1,491		1,056	
1998	2,500	701	3,201		3,253	
1999	2,150	–	2,150		–	
1 - 5 years	10,086	2,244	12,330	9.3	11,301	10.0
6 - 10 years	8,651	933	9,584	10.1	9,918	10.2
11 - 15 years	2,929	–	2,929	10.2	2,547	10.0
16 - 20 years	1,634	2,143	3,777	11.3	4,905	11.0
21 - 25 years	–	–	–	–	648	10.0
26 years and over	4,308	–	4,308	10.1	4,326	10.1
	27,608	5,320	32,928	10.0	33,645	10.2

9. LONG-TERM DEBT *(continued) (millions of dollars)*

As described in note 12, Ontario Hydro has used various derivative financial instruments to hedge the foreign exchange exposure related to long-term debt denominated in foreign currencies. The following table summarizes the currencies in which Ontario Hydro's long-term debt is payable, before and after giving effect to Ontario Hydro's hedging activities:

	1994		1993	
	Principal Outstanding		Principal Outstanding	
	Before Hedging	After Hedging	Before Hedging	After Hedging
Canadian dollars	27,608	29,484	27,838	30,080
United States dollars	5,088	3,444	5,673	3,565
Swiss francs	161	–	134	–
Japanese yen	71	–	–	–
	32,928	32,928	33,645	33,645

Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

Bonds and notes payable in United States dollars include $1,091 million (1993 - $2,052 million) of Ontario Hydro bonds held by the Province of Ontario having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

As described in note 12, Ontario Hydro has used various derivative financial instruments to manage the interest rate risk associated with its outstanding long-term debt.

10. BANK INDEBTEDNESS

Short-term bank lines of credit are available to Ontario Hydro in the amount of $600 million (1993 - $600 million), of which $595 million was utilized at year end (1993 - $575 million). The lines of credit are unsecured and bear interest at less than the prime rate.

11. SHORT-TERM NOTES PAYABLE *(millions of dollars)*

	1994	1993
Short-term notes used for cash management	265	191
Short-term notes used for long-term financing	864	918
	1,129	1,109

Certain bond issues were called and refinanced at favourable interest rates by issuing short-term notes. Financial arrangements were also entered into so as to achieve a fixed interest rate on most of the refinanced issues.

12. DERIVATIVE FINANCIAL INSTRUMENTS *(millions of stated currency)*

Ontario Hydro has used a variety of derivative financial instruments to manage foreign exchange and interest rate risk. Derivative financial instruments expose Ontario Hydro to credit risk, since there is a risk of counterparty default. This

12. DERIVATIVE FINANCIAL INSTRUMENTS *(continued) (millions of stated currency)*

risk is limited to the cost of replacing contracts in which Ontario Hydro has an unrealized gain. Credit risk is monitored and minimized by dealing only with highly rated counterparties. The following table summarizes outstanding positions in derivative financial instruments as at December 31, 1994:

	1994				1993	
	Notional Principal Outstanding					
	Maturing in 1995	Maturing beyond 1995	Total	Weighted Average Rate	Notional Principal Outstanding Total	Weighted Average Rate
Foreign exchange risk management techniques:						
Forward exchange contracts						
Purchased forward	US$309	US$259	US$568	$1.33	US$1,128	$1.26
Sold forward	US$1	US$181	US$182	$1.35	US$185	$1.35
Cross currency swap contracts						
Ontario Hydro receives foreign currency:						
United States dollar	US$600	US$56	US$656	$1.17[1]	US$656	$1.17[1]
Swiss franc	nil	SF150	SF150	$1.00[1]	SF150	$1.00[1]
Japanese yen	nil	¥5,000	¥5,000	$0.013[1]	nil	nil
[1]contracted rate for exchange of principal						
Foreign currency option combination contracts	US$549	nil	US$549	n/a	nil	n/a
Interest rate risk management techniques:						
Swaption contracts sold						
Ontario Hydro potentially pays fixed	nil	C$2,199	C$2,199	10.7%	C$2,628	10.5%
	nil	US$777	US$777	14.8%	US$1,043	13.5%
Interest rate swap contracts						
Ontario Hydro receives fixed	nil	C$3,115	C$3,115	7.1%	C$1,425	6.2%
	nil	US$500	US$500	5.1%	US$500	5.1%
Ontario Hydro pays fixed	C$3,701	C$459	C$4,160	6.1%	C$4,663	5.9%
	US$540	US$255	US$795	4.9%	US$1,029	4.5%
Forward rate agreements						
Ontario Hydro pays forward rate	C$795	nil	C$795	6.2%	nil	nil
	US$177	nil	US$177	6.0%	nil	nil

Foreign exchange risk management techniques

Forward exchange contracts: Ontario Hydro has entered into forward exchange contracts to purchase US dollars, the majority of which hedge US dollar principal and interest payments on bond issues. In addition, forward exchange contracts were entered into to sell US dollars to hedge some future US dollar revenues.

12. DERIVATIVE FINANCIAL INSTRUMENTS *(continued)*

Cross currency swap contracts: Ontario Hydro has entered into cross currency swap contracts to effectively convert foreign currency principal and interest payments on selected debt issues into Canadian dollars.

Foreign currency option combination contracts: Ontario Hydro has entered into foreign currency option combination contracts to hedge against the impact of a potential decline in the value of the Canadian dollar in 1995. These contracts provide Ontario Hydro with protection against a decline in the value of the Canadian dollar within a particular range of exchange rates. As a result of these contracts, Ontario Hydro does not benefit from a rise in the value of the Canadian dollar beyond a particular level.

Interest rate risk management techniques

Swaption contracts sold: Several of Ontario Hydro's outstanding bond issues are callable by Ontario Hydro at fixed prices on dates before their stated maturities. In 1993 Ontario Hydro converted future potential interest savings related to call options embedded in certain of its bonds to cash, by selling offsetting swaption contracts. These contracts permit holders to require Ontario Hydro to enter into interest rate swaps commencing on the call date. If exercised, the swaptions result in Ontario Hydro making payments based on a fixed interest rate equal to the related bonds' coupon rates, and receiving floating rate payments. Premiums received from the sale of these contracts are being amortized to income, as a reduction of interest expense, over the remaining terms of the related bond issues.

Interest rate swap contracts: As at December 31, 1994, the outstanding receive-fixed interest rate swap contracts have effectively converted fixed interest rates on long-term debt to floating interest rates. These contracts have maturity dates over the period 1998 to 2004. The outstanding pay-fixed interest rate swap contracts have effectively converted floating interest rates on outstanding debt into fixed interest rates. The majority of the Canadian dollar pay-fixed interest rate swaps mature in 1995, while the US dollar pay-fixed interest rate swaps mature over the period 1995 to 2002.

Forward rate agreements: Ontario Hydro has entered into forward rate agreements to hedge against a rise in short-term borrowing rates in early 1995. The agreements effectively fix Ontario Hydro's interest costs for terms of three months or less beginning in early 1995.

After giving effect to interest rate derivative financial instruments outstanding as at December 31, 1994, the total amount of long-term debt, bank indebtedness and short-term notes maturing or subject to interest rate resetting in 1995 is approximately $8,600 million. This amount will be affected by treasury activities and the borrowing program in 1995.

13. ACCRUED FIXED ASSET REMOVAL AND USED NUCLEAR FUEL DISPOSAL COSTS *(millions of dollars)*

	1994	1993
Accrued fixed asset removal costs		
– accrued decommissioning costs	621	588
– accrued fuel channel removal costs	519	394
	1,140	982
Accrued used nuclear fuel disposal costs	908	791
	2,048	1,773

Fixed asset removal costs

Fixed asset removal costs are the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives, and the costs of removing certain fuel channels which are expected to be replaced during the life of the nuclear reactors.

13. ACCRUED FIXED ASSET REMOVAL AND USED NUCLEAR FUEL DISPOSAL COSTS *(continued)*

The significant assumptions used in estimating fixed asset removal costs were:

- decommissioning of nuclear generating stations in the 2042 to 2062 period on a deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- dismantlement of Bruce Heavy Water Plants "A", "B" and "D" in the 1994 to 2005 period;
- interest rates through to 2065 ranging from 8% to 10% (1993 - 9% to 10%);
- escalation rates through to 2065 ranging from 2% to 7% (1993 - 3% to 7%); and
- removal of fuel channels in nuclear generating stations during the following periods (1993 comparative in brackets):

Bruce "A" Units 1,3 & 4	1997 to 2007 (1994 to 2007)
Pickering "B"	2009 to 2016 (2009 to 2016)
Bruce "B"	2011 to 2019 (2011 to 2019)
Darlington	2016 to 2024 (2016 to 2024).

Because of possible changes to the above factors and the methods used for decommissioning and fuel channel removal, these costs are subject to revision. In February 1994, Ontario Hydro decided to shut down Unit 2 at Bruce "A" Nuclear Generating Station in 1995. The accumulated fixed asset removal provision relating to the retubing of Unit 2 was used to reduce the amount relating to the shutdown of Unit 2 charged to the 1993 corporate restructuring charge.

Used nuclear fuel disposal costs

The significant assumptions used in estimating the future used nuclear fuel disposal costs were:

- an in-service date of the year 2025 (1993 - 2025) for used nuclear fuel disposal facilities;
- a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 8% to 10% (1993 - 9% to 10%); and
- escalation rates through to the disposal date ranging from 2% to 7% (1993 - 3% to 7%).

Because of the uncertainties associated with the technology of disposal and the above factors, these costs are subject to change.

14. CONTINGENCIES

Manitoba Hydro

In December 1992, due to a projected surplus in generating capacity, Ontario Hydro exercised its right to terminate its long-term power purchase contract with Manitoba Hydro. In Manitoba Hydro's certificate of costs for reimbursement, an amount of $49 million was claimed for costs incurred by Manitoba Hydro prior to entering into the contract with Ontario Hydro on December 7, 1989. Ontario Hydro is of the opinion that costs incurred by Manitoba Hydro before December 7, 1989 are not reimbursable by Ontario Hydro under the contract. As well, based on a review of the certificate of costs, it appears that the total cost claimed by Manitoba Hydro may have been overstated. Ontario Hydro has commenced an action against Manitoba Hydro for a declaration that Ontario Hydro is not obliged to pay costs incurred prior to entering into the contract and for a further judgment against Manitoba Hydro requiring the repayment of amounts which were improperly claimed by Manitoba Hydro and paid by Ontario Hydro under the contract. In July 1994, Manitoba Hydro issued its statement of defence and counterclaim to Ontario Hydro. Manitoba Hydro claims that they are entitled to an immediate payment from Ontario Hydro of $55 million, representing the claim for costs incurred by Manitoba Hydro prior to entering into the contract, plus interest. At this time, the outcomes of these claims are not determinable, and as such, no provision has been accrued in Ontario Hydro's financial statements with respect to any amounts in dispute.

15. RETAINED EARNINGS *(millions of dollars)*

	1994	1993
Balance at beginning of year	3,325	6,931
Net income (loss)	587	(3,604)
Net refunds on annexation by municipalities	–	(2)
Balance at end of year	3,912	3,325

The balance in this account is retained for purposes prescribed under the Power Corporation Act.

16. CONSOLIDATED STATEMENT OF CHANGES IN CASH POSITION *(millions of dollars)*

Cash position is defined to be cash and short-term investments less bank indebtedness and short-term notes used for cash management.

Cash position is comprised of the following:	1994	1993
Bank indebtedness	(647)	(615)
Short-term notes used for cash management (note 11)	(265)	(191)
	(912)	(806)

The changes in non-cash balances related to operations consisted of the following:	1994	1993
Accounts receivable - (increase)	(51)	(175)
Fuel for electric generation - decrease	143	286
Materials and supplies - decrease (increase)	2	(7)
Accounts payable and accrued charges - (decrease) increase	(73)	43
Accrued interest - (decrease) increase	(87)	28
Long-term accounts payable and accrued charges - increase	46	36
	(20)	211

17. BENEFIT PLANS

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan, the long-term disability plan and the group health care plan.

Pension plan

Regular pension costs for 1994 were $76 million (1993 - $161 million). In 1994, $50 million (1993 - $106 million) of the pension costs were charged to operations and $26 million (1993 - $55 million) were capitalized. In addition, included in the corporate restructuring charge are costs of $19 million associated with the 1994 staff reduction program (1993 - $327 million). Effective January 1, 1994, Ontario Hydro implemented certain changes with respect to accounting for pension costs. Pension plan assets are valued using current market values and pension plan adjustments are amortized on a straight-line basis over the expected average remaining period of service of the employees covered by the Ontario Hydro pension plan. Previously, pension plan assets were valued using a five-year market value average and pension plan adjustments were amortized on an annuity basis. These changes in accounting for pension costs have no material effect on pension costs for 1994.

17. BENEFIT PLANS *(continued)*

The pension costs for 1994 were actuarially determined for accounting purposes using the following significant assumptions which take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits - 8.00% (1993 - 6.50%);
- rate used to estimate interest cost - 8.00% (1993 - 6.50%);
- rate used to estimate return on investments - 9.00% (1993 - 8.75%);
- salary schedule escalation rate - 3.00% (1993 - 3.50%);
- average long-term rate used to estimate improvements in pension benefits to partially offset the effect of increase in cost of living - 1.69% (1993 - 2.44%); and
- average remaining service period of employees - 17 years (1993 - 17 years).

Based on these assumptions, the actuarial present value of the accrued pension benefits is estimated to be $5,700 million as at December 31, 1994 (1993 - $7,201 million), and the pension plan assets available for these benefits were approximately $6,700 million based on current market values (1993 - $6,317 million based on a five-year market value average).

Deferred pension costs on the statement of financial position represent the cumulative difference between the funding contributions, including special payments, and pension costs. As at December 31, 1994, the deferred pension costs amounted to $169 million (1993 - $208 million) and primarily reflect special payments made in 1990 and 1991 relating to past service benefit improvements offset by costs associated with the 1993 voluntary staff reduction program. The costs of pension benefit improvements funded by the special payments are being amortized as a charge to pension costs on a straight-line basis over the average remaining service period of employees.

Long-term disability plan

The long-term disability plan is entirely funded by Ontario Hydro. For 1994 contributions to the plan amounted to $4 million (1993 - $12 million).

Group life insurance plan

Ontario Hydro paid $3 million (1993 - $5 million) in premiums for basic insurance coverage for employees. Premiums for additional coverage, if requested, are paid for by the employee.

Group health care plan

Ontario Hydro provides a group health care plan to its employees. In 1994, the cost of providing these benefits was $61 million (1993 - $63 million).

Other post-retirement benefits

In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as the benefits are paid. In 1994, the cost of providing these benefits was $19 million (1993 - $15 million).

18. RESEARCH AND DEVELOPMENT

In 1994, approximately $128 million of research and development costs were charged to operations and $37 million were capitalized (1993 - $129 million and $42 million, respectively).

19. COMPARATIVE FIGURES

Certain of the 1993 comparative figures in the financial statements have been reclassified to conform with the 1994 financial statement presentation.

Five-Year Summary of Financial and Operating Statistics

(millions of dollars)

	1994	1993	1992	1991	1990
Revenues					
Primary power and energy					
Municipal utilities	5,829	5,721	5,281	4,873	4,373
Retail customers	1,688	1,641	1,568	1,397	1,297
Direct industrial customers	866	873	863	811	792
	8,383	8,235	7,712	7,081	6,462
Secondary power and energy	349	128	56	62	22
	8,732	8,363	7,768	7,143	6,484
Costs					
Operation, maintenance and administration	1,705	2,060	2,246	2,037	1,927
Fuel used for electric generation	577	911	1,137	1,122	1,020
Power purchased	316	260	186	151	477
Provincial government levies	284	286	270	252	235
Depreciation and amortization	1,593	1,506	1,198	1,136	908
	4,475	5,023	5,037	4,698	4,567
Income before financing charges	4,257	3,340	2,731	2,445	1,917
Financing charges					
Gross interest	3,544	3,849	3,782	3,586	3,204
Capitalized interest	(110)	(453)	(1,231)	(1,194)	(1,318)
Investment income	(74)	(74)	(119)	(158)	(83)
Foreign exchange	42	8	(13)	7	(15)
	3,402	3,330	2,419	2,241	1,788
Income before restructuring charge	855	10	312	204	129
Corporate restructuring charge and writeoffs	268	3,614	-	-	-
Net income (loss)	587	(3,604)	312	204	129
Financial position					
Total assets	44,085	44,706	46,671	43,244	39,373
Fixed assets	39,817	40,740	40,690	38,170	35,139
Long-term debt[1]	32,967	33,685	34,034	32,160	29,378
Equity	3,912	3,325	6,931	6,619	6,416
Cash flows					
Cash provided from operating activities	2,227	1,332	1,691	1,381	754
Cash provided from financing activities	(1,245)	404	1,784	2,743	2,515
Cash used for investment in fixed assets	997	1,871	3,375	3,356	3,592
Investment in fixed assets	1,072	2,296	3,527	3,934	3,544

	1994	1993	1992	1991	1990
Financial indicators					
Interest coverage - before restructuring charge[2]	1.25	1.00	1.09	1.06	1.04
Interest coverage - after restructuring charge[2]	1.17	0.04	-	-	-
Debt ratio[3]	0.904	0.918	0.841	0.838	0.829
Primary energy sales[4] *millions of kilowatt-hours*					
Municipal utilities	93,347	92,047	91,317	93,623	92,116
Retail customers	18,499	18,519	18,938	18,988	19,444
Direct industrial customers	17,182	17,221	18,094	18,353	19,315
	129,028	127,787	128,349	130,964	130,875
Secondary energy sales[4] *millions of kilowatt-hours*	12,628	4,807	1,896	2,123	577
Energy and Demand					
Installed dependable peak capacity *megawatts*[5]	34,432	34,537	32,863	32,669	31,672
December primary peak demand *megawatts*	21,849	20,506	21,339	22,933	21,785
Primary energy made available *millions of kilowatt-hours*[6]	134,874	133,769	134,376	136,966	136,744
Number of primary customers[4]					
Municipal utilities	306	309	311	311	314
Retail customers	954,440	942,812	940,617	925,641	918,368
Direct industrial customers	103	104	107	109	119
Average revenue[4] *in cents per kilowatt-hour of total energy sales*					
Primary power and energy					
Municipal utilities	6.244	6.216	5.783	5.205	4.747
Retail customers	9.684	9.265	8.884	7.883	7.352
Direct industrial customers	5.040	5.069	4.770	4.419	4.100
All primary customers combined	6.551	6.485	6.070	5.459	5.024
Secondary power and energy	2.764	2.663	2.954	2.920	3.813
All classifications combined	6.211	6.346	6.024	5.419	5.001
Average rate increases *expressed as a per cent*					
Municipal utilities	0.0	8.2	11.8	8.7	6.1
Retail customers	0.0	6.5	11.8	8.7	5.3
Direct industrial customers	0.0	8.2	11.8	7.8	5.6
All primary customers combined	0.0	7.9	11.8	8.6	5.9

Five-Year Summary of Financial and Operating Statistics

(continued)

	1994	1993	1992	1991	1990
Average cost[4,7] *in cents per kilowatt-hour of energy generated*					
Hydroelectric					
Operation, maintenance and administration	.307	.277	.280	.299	.271
Water rentals	.336	.330	.317	.338	.303
Depreciation, debt guarantee fee and financing charges	.543	.488	.454	.424	.373
	1.186	1.095	1.051	1.061	.947
Nuclear					
Operation, maintenance and administration	.948	1.017	1.229	1.033	1.100
Uranium	.270	.514	.515	.502	.490
Depreciation, debt guarantee fee and financing charges	3.529	3.910	3.080	2.756	2.631
	4.747	5.441	4.824	4.291	4.221
Fossil					
Operation, maintenance and administration	1.310	1.303	.960	.839	.899
Coal, gas and oil	2.378	2.515	2.426	2.388	2.479
Depreciation, debt guarantee fee and financing charges	3.607	3.011	1.645	1.489	1.274
	7.295	6.829	5.031	4.716	4.652
Average number of employees[4]					
Regular	22,525	26,442	28,835	28,396	26,821
Non-regular[8]	2,082	3,331	6,004	7,309	9,653

1 Long-term debt includes long-term debt payable within one year.

2 Interest coverage represents net income plus interest on bonds, notes, and other debt divided by interest on bonds, notes and other debt.

3 Debt ratio represents debt (bonds and notes payable, short-term notes payable, other long-term debt, unamortized swaption premiums, accrued fixed asset removal and used nuclear fuel disposal costs and bank indebtedness less unamortized foreign exchange gains and losses) divided by debt plus equity.

4 Figures for 1994 are preliminary.

5 Installed dependable peak capacity represents the net output power supplied by all generating units, non-operating reserve facilities (1994 - 4,297 MW; 1993 - 2,686 MW; 1992 - 1,554 MW; 1991 - 1,546 MW; and 1990 - 1,551 MW), net firm power purchase contracts and purchases from non-utility generators.

6 Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.

7 Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.

8 The majority of non-regular staff are construction trades persons.

CUSTOMERS SERVED BY ONTARIO HYDRO AND ASSOCIATED MUNICIPAL UTILITIES

	1994[1]	1993	1992	1991	1990
Total number of customers *in thousands*					
Residential	3,298	3,252	3,205	3,163	3,129
Farm	103	103	104	105	105
Commercial and industrial	438	436	430	428	420
	3,839	3,791	3,739	3,696	3,654
Average annual use *in kilowatt-hours per customer*					
Residential	10,917	10,965	11,024	11,581	11,668
Farm	23,138	23,660	23,496	23,945	23,945
Commercial and industrial	201,000	198,841	201,112	205,982	212,193
Average revenue[2] *in cents per kilowatt-hour*					
Residential	8.82	8.77	8.12	7.23	6.68
Farm	8.93	8.82	8.19	7.34	6.80
Commercial and industrial	6.75	6.76	6.31	5.70	5.22
All customers	7.38	7.38	6.86	6.16	5.67

1 Figures for 1994 are preliminary.
2 Includes rural rate assistance.




ONTARIO HYDRO | 1995 ANNUAL REPORT

Finding New Paths To The Customer





Consolidated Statement of Operations

for the year ended December 31 (millions of dollars)

	1995	1994
Revenues		
Primary power and energy		
Municipal utilities	5,899	5,829
Retail customers	1,635	1,688
Direct industrial customers	914	866
	8,448	8,383
Secondary power and energy (note 2)	233	349
Other revenues	315	264
	8,996	8,996
Costs		
Operation, maintenance and administration	1,931	1,935
Fuel used for electric generation	592	586
Power purchased	495	341
Provincial government levies (note 3)	283	284
Depreciation and amortization (note 4)	1,640	1,595
	4,941	4,741
Income before financing charges	4,055	4,255
Financing charges (note 5)	3,427	3,400
Income before corporate restructuring charge	628	855
Corporate restructuring charge (note 6)	–	268
Net income	628	587

See accompanying notes to financial statements.

Consolidated Statement of Financial Position

as at December 31 (millions of dollars)

Assets	1995	1994
Fixed assets (note 7)		
Fixed assets in service	**50,485**	49,678
Less accumulated depreciation	**12,662**	11,239
	37,823	38,439
Construction in progress	**1,476**	1,468
	39,299	39,907
Current assets		
Accounts receivable	**1,144**	1,282
Fuel for electric generation (note 8)	**377**	519
Materials and supplies, at cost	**282**	283
	1,803	2,084
Other assets		
Deferred debt costs	**840**	1,046
Deferred pension costs (note 17)	**149**	169
Deferred demand management costs, net of accumulated amortization	**411**	396
Long-term accounts receivable and other assets	**482**	498
	1,882	2,109
	42,984	44,100

See accompanying notes to financial statements.

LIABILITIES	1995	1994
Long-term debt (note 9)	28,726	30,202
Current liabilities		
Bank indebtedness (note 10)	604	603
Accounts payable and accrued charges	1,007	1,271
Short-term notes payable (note 11)	934	1,129
Accrued interest	879	891
Long-term debt payable within one year (note 9)	2,704	2,765
	6,128	6,659
Other liabilities		
Unamortized swaption premiums (note 12)	657	696
Long-term accounts payable and accrued charges	514	583
Accrued fixed asset removal and used nuclear fuel disposal costs (note 13)	2,419	2,048
	3,590	3,327

CONTINGENCIES & COMMITMENTS (NOTES 12 & 14)

EQUITY

Retained earnings (note 15)	4,540	3,912
	42,984	44,100

On behalf of the Board,

Chairman, Board of Directors

President & Chief Executive Officer

Toronto, Canada,
April 16, 1996

Consolidated Statement of Changes in Cash Position

for the year ended December 31 (millions of dollars)

	1995	1994
Operating activities		
Net income	628	587
Adjust for non-cash items		
Depreciation and amortization	1,640	1,595
Provision for corporate restructuring	–	33
Amortization of foreign exchange gains and losses	55	52
Provision for used nuclear fuel disposal costs	73	93
Other	63	(112)
	2,459	2,248
Change in non-cash balances related to operations (note 16)	20	8
	2,479	2,256
Financing activities		
Debt for long-term financing		
Issued	2,494	2,737
Retired	(3,206)	(3,700)
	(712)	(963)
Redemption of debt for long-term financing, net of re-issuances	(1,229)	(210)
Cash paid on settlement of swaptions	–	(72)
	(1,941)	(1,245)
Investing activities		
Fixed assets	(932)	(1,089)
Other assets	138	16
	(794)	(1,073)
Change in cash position during the year	(256)	(62)
Cash position at beginning of year	(868)	(806)
Cash position at end of year (note 16)	(1,124)	(868)

See accompanying notes to financial statements.

Notes to Financial Statements

1. Summary of significant accounting policies

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in Canada, applied on a basis consistent with that of the preceding year. The significant accounting policies followed by Ontario Hydro are described below.

a) Rate setting

Ontario Hydro has broad powers to generate, supply and deliver electric power throughout the Province of Ontario. The Corporation operates under the Power Corporation Act and is subject to the provisions of the Ontario Energy Board Act.

Under the provisions of the Power Corporation Act, the price payable by municipal and other customers for power is the cost of supplying the power. Such cost is defined in the Act to include the cost of operating and maintaining the system, the cost of energy conservation programs, depreciation, interest, and the annual amounts for debt retirement and stabilization of rates and contingencies. The annual amounts for debt retirement and stabilization of rates and contingencies are accounted for as net income.

Under the provisions of the Ontario Energy Board Act, a public hearing before the Ontario Energy Board is required to review any changes in electricity rates proposed by Ontario Hydro which affect its municipal utilities, direct industrial customers, or, if the Minister of Energy so directs, rural retail customers. The Ontario Energy Board then submits its recommendations to the Minister of Environment and Energy. After considering the recommendations of the Ontario Energy Board, Ontario Hydro's Board of Directors, under the authority of the Power Corporation Act, establishes the electricity rates to be charged to customers.

The Board of Directors may specify that an amount related to an item be included in electricity rates of a period which differs from the period in which it would be recognized under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment. If so, the accounting treatment given the item is the same as its treatment for rate-setting purposes. This authority of the Board of Directors may be used in respect of a specific transaction or an accounting policy.

Ontario Hydro's accounting policies relating to discounts and premiums arising from the acquisition of debt prior to maturity and foreign exchange gains and losses on United States dollar-denominated short-term financing replacing United States dollar-denominated long-term debt which has been redeemed prior to maturity, reflect the rate-setting treatment of these items as specified by the Board of Directors. Under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment these amounts would be included as gains or losses of the current period. The Board of Directors has also used its rate-setting authority to specify that costs of the rehabilitation program for steam generators at Pickering "A" and "B" and Bruce "A" Nuclear Generating Stations shall be deferred for recovery in future periods. Under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment these costs would be expensed as incurred.

b) Consolidation

The consolidated financial statements include the financial statements of Ontario Hydro and its wholly-owned subsidiary Ontario Hydro International Inc. (OHI Inc.). OHI Inc. was incorporated under the Ontario Business Corporations Act and was established as a subsidiary of Ontario Hydro in September, 1993. OHI Inc. publishes separate financial statements.

c) Fixed assets

Fixed assets in service include operating facilities and non-operating reserve facilities, and heavy water held for use in nuclear generating stations. Construction in progress includes fixed assets under construction.

Fixed assets are capitalized at cost which comprises material, labour, engineering costs, overheads, depreciation on service equipment, interest applicable to capital construction activities, and for new facilities, the costs of training initial operating staff. In the case of generating facilities, the cost also includes the net cost of commissioning which comprises the cost of start-up less the value attributed to energy produced by generation facilities during their commissioning period. For multi-unit facilities, a proportionate share of the cost of common facilities is placed in service with each major operating unit. The cost of heavy water comprises the direct cost of production and applicable overheads, as well as interest and depreciation on the heavy water production facilities and the estimated removal costs of these facilities. Leases which transfer the benefits and risks of ownership of assets to Ontario Hydro are capitalized.

Interest is capitalized on construction in progress at rates (1995 – 10.1 per cent; 1994 – 10.2 per cent) which approximate the average cost of all long-term funds borrowed. If the construction period of a project is extended and the construction activities are continued, interest is capitalized during the period of extension provided that the project has a reasonable expectation of being completed.

If a project is cancelled or deferred indefinitely with a low probability of resuming construction, all costs, including the costs of cancellation, are written off to operations.

If fixed assets are removed from operations and mothballed for future use, classified as non-operating reserve facilities, the costs of mothballing are charged to operations.

d) Depreciation

The capital costs of fixed assets in service are depreciated on a straight-line basis, with the exception of heavy water held to replace losses occurring during the operation of Ontario Hydro's nuclear generating stations. Heavy water held for this purpose is depreciated on a sinking fund basis over the period through to the first year heavy water from an out-of-service nuclear station is estimated to be available for replacement purposes. Depreciation rates for the various classes of assets are based on their estimated service lives. Major components of fossil and nuclear generating stations are depreciated over the lesser of the service life expectancy of the major component or the remaining service life of the associated generating station; for hydroelectric generating stations, major components are depreciated over the service life expectancy of the component, ranging from 25 to 100 years. The estimated service lives of assets in the major classes are:

Generating stations	– fossil	– 40 years
	– nuclear	– 40 years
Heavy water	– in nuclear generating stations	– over the period ending in the year 2040
	– held for use in nuclear generating stations	– over the period ending in the year 2011
Transmission and distribution facilities		– 10 to 100 years
Administration and service facilities		– 5 to 50 years

In accordance with group depreciation practices, for normal retirements the cost of fixed assets retired is charged to accumulated depreciation with no gain or loss reflected in operations. However, gains and losses on sales of fixed assets and losses on premature retirements are charged to operations in the year incurred as adjustments to depreciation expense.

When the costs of removal less residual value on retirements of fixed assets can be reasonably estimated and are significant, provisions for these costs are charged to depreciation expense on an annuity basis over the remaining service life of the related fixed assets. Removal costs that are provided for include the estimated costs of decommissioning nuclear and fossil stations and the estimated costs of removing certain nuclear reactor fuel channels. Other removal costs are charged to depreciation expense as incurred.

The estimated service lives of fixed assets and the significant assumptions underlying the estimates of fixed asset removal costs are subject to periodic review which could result in changes. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in electricity prices.

Non-operating reserve facilities are amortized so that any estimated loss in value is charged to depreciation expense on a straight-line basis over their expected non-operating period.

e) Heavy water sales

Ontario Hydro has produced sufficient quantities of heavy water to meet future needs of its existing nuclear generating stations and is now producing heavy water for sales to external parties. Revenues from external sales contracts requiring the production of heavy water far in advance of delivery dates are recognized on a percentage-of-completion basis and revenues from all other heavy water sales are recognized at the point of sale. Resulting profits or losses are credited or charged to operations in the year incurred.

f) Fuel for electric generation

Fuel used for electric generation comprises the average inventory costs of fuel consumed, the value attributed to commissioning energy produced, and provisions for disposal of nuclear fuel used during the period. The inventory cost of fuel comprises fuel purchases, transportation and handling costs.

The costs for disposal of nuclear fuel used in each period are charged to operations based on estimated future expenditures and interest accumulating to the estimated date of disposal. Estimates of expenditures, interest and escalation rates, and the date of disposal are subject to periodic review. Adjustments resulting from changes in estimates are charged to operations on an annuity basis over the period from the year the changes can first be reflected in electricity prices to the estimated in-service date of the disposal facility.

g) Foreign currency translation

Current monetary assets and liabilities in foreign currencies are translated to Canadian currency at year-end rates of exchange, and the resultant exchange gains or losses are credited or charged to operations. Long-term debt payable in foreign currencies is translated to Canadian currency at year-end rates of exchange. Resulting unrealized exchange gains or losses are deferred and included in deferred debt costs, and are amortized to operations on an annuity basis over the remaining life of the related debt.

Foreign exchange gains or losses on hedges of long-term debt payable in foreign currencies are deferred and included in deferred debt costs. The deferred gains or losses on hedges are amortized to operations on an annuity basis in the periods the hedges provide benefit.

Foreign exchange gains or losses on early redemption of long-term debt, including subsequent gains and losses on short-term replacement financing, are deferred and included in deferred debt costs if the exposure in the foreign currency related to the redeemed debt is continued by refinancing the redeemed debt in the same currency. These deferred gains or losses are amortized on an annuity basis over the period to the original maturity date of the redeemed debt. If the foreign currency exposure is reduced as a result of the early redemption of debt, the resulting foreign exchange gains or losses related to the redeemed debt are credited or charged to operations.

h) Deferred debt costs

Deferred debt costs include the unamortized amounts related to unrealized foreign exchange gains or losses resulting from the translation of foreign currency long-term debt; deferred foreign exchange gains or losses on hedges; deferred foreign exchange gains or losses on the early redemption of long-term debt; discounts or premiums arising from the issuance of debt or the acquisition of debt prior to maturity; discounts or premiums accrued on foreign currency hedges; and net unamortized premiums on settled, exercised or expired swaption contracts.

Discounts or premiums arising from the issuance of debt are amortized over the period to maturity of the debt on an annuity basis when the term of the debt exceeds one year and on a straight-line basis when the term is one year or less. Discounts or premiums on debt acquired prior to the date of maturity are amortized on an annuity basis over the period from the acquisition date to the original maturity date of the debt. Discounts or premiums on foreign currency hedges are credited or charged to operations on an annuity basis over the terms of the individual hedges. Net unamortized premiums on settled, exercised or expired swaption contracts are amortized on an annuity basis over the period from the settlement, exercise or expiry date to the original maturity date of the related debt.

i) Demand management

Demand management activities undertaken by Ontario Hydro encourage customers to conserve or use electricity more efficiently. Demand management costs that have reasonably assured and specifically identifiable future benefits to Ontario Hydro are deferred and amortized to operations on a straight-line basis over the periods that benefit. All other costs are charged to operations as incurred. The benefit periods of deferred demand management costs are subject to periodic review which could result in changes. Any changes arising out of such a review are implemented on a remaining benefit period basis from the year the changes can first be reflected in electricity prices.

1. Summary of Significant Accounting Policies *(continued)*

j) Pension plan
The pension plan is a contributory, defined benefit plan covering all regular employees of Ontario Hydro. Pension costs for accounting purposes are actuarially determined using the projected benefit method prorated on services and based on assumptions that reflect management's best estimate of the effect of future events on the actuarial present value of accrued pension benefits. Pension plan assets are valued using current fair values and pension plan adjustments are amortized on a straight-line basis over the expected average remaining period of service of the employees covered by the Ontario Hydro pension plan.

k) Research and development
Research and development (R&D) costs are charged to operations in the year incurred, except for: R&D costs related directly to the design or construction of a specific capital facility, which are capitalized as part of the cost of the facility; R&D costs incurred to discharge long-term obligations, and for which specific provision has already been made, which are charged to the appropriate accumulated provision; and development costs incurred for products being developed for resale provided they meet specific criteria related to technical, market and financial feasibility, which are deferred and amortized to operations over a maximum period of 10 years from the date of completion of the project.

2. Secondary Power and Energy

Secondary power and energy revenues include $231 million (1994 - $345 million) from sales of electricity to United States utilities.

3. Provincial Government Levies *(millions of dollars)*

	1995	1994
Provincial water rentals	113	110
Provincial debt guarantee fee	170	174
	283	284

Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydroelectric generation. The Province of Ontario has legislated that Ontario Hydro pay to the Province an annual debt guarantee fee of one half of one percent on the total debt guaranteed by the Province, outstanding as of the preceding December 31.

4. Depreciation and Amortization *(millions of dollars)*

	1995	1994
Depreciation of fixed assets in service	1,469	1,423
Amortization of deferred demand management costs	31	31
Fixed asset removal costs	98	137
Other removal costs	53	13
	1,651	1,604
Less:		
Depreciation charged to construction in progress	9	8
Other	2	1
	11	9
	1,640	1,595

5. Financing Charges *(millions of dollars)*

		1995	1994
Interest on bonds, notes and other debt	– long-term	3,227	3,331
	– short-term	149	101
Interest on accrued fixed asset removal and used nuclear fuel disposal costs		198	112
		3,574	3,544
Less:			
Interest charged to	– construction in progress	74	117
	– fuel for electric generation	4	6
Interest earned on investments		123	63
		201	186
Interest charged to operations		3,373	3,358
Foreign exchange		54	42
		3,427	3,400

6. Corporate Restructuring Charge *(millions of dollars)*

	1995	1994
Staff reduction and relocation costs	–	268
	–	268

In 1994 through a review of the restructuring program initiated in 1993 and the business planning process, the Corporation identified the need for additional staff reductions of approximately 2,400 positions. A Special Separation Plan was approved by the Board of Directors in December 1994 to attract as many voluntary staff departures as possible, with the balance to be achieved through involuntary measures, if required. A provision of $268 million was charged against income for 1994 to cover the estimated cost of the voluntary and involuntary staff reductions as well as costs related to surplus assets, lease cancellations and relocation costs related to the staff reductions.

7. Fixed Assets *(millions of dollars)*

1995

		Fixed Assets in Service	Accumulated Depreciation	Construction in Progress
Generating stations	– hydroelectric	2,512	832	624
	– fossil	5,442	2,287	42
	– nuclear	24,738	4,873	490
Heavy water	– in nuclear generating stations	4,025	721	–
	– held to replace losses	1,321	60	–
Transmission and distribution facilities		10,611	2,890	300
Administration and service facilities		1,836	999	20
		50,485	12,662	1,476

1994

		Fixed Assets in Service	Accumulated Depreciation	Construction in Progress
Generating stations	– hydroelectric	2,405	800	601
	– fossil	5,344	2,083	36
	– nuclear	24,375	4,141	486
Heavy water	– in nuclear generating stations	4,025	617	–
	– held to replace losses	1,318	28	–
Transmission and distribution facilities		10,363	2,646	342
Administration and service facilities		1,848	924	3
		49,678	11,239	1,468

Nuclear steam generator rehabilitation costs

Ontario Hydro has undertaken a major program to rehabilitate steam generators at Pickering "A" and "B" and Bruce "A" Nuclear Generating Stations. Costs of the program, which will continue until 1998, have been deferred and will be amortized over the remaining service lives of the individual generators commencing as each generator is returned to service. Deferred nuclear steam generator rehabilitation costs of $125 million are included in nuclear generating station construction in progress as at December 31, 1995 (December 31, 1994 - $71 million).

8. Fuel for electric generation *(millions of dollars)*

		1995	1994
Inventories	– uranium	**111**	135
	– coal	**225**	319
	– oil	**41**	65
		377	519

9. Long-term debt *(millions of dollars)*

	1995	1994
Bonds and notes payable	**31,395**	32,928
Other long-term debt	**35**	39
	31,430	32,967
Less payable within one year	**2,704**	2,765
	28,726	30,202

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity in the following table:

(millions of dollars)

Years of Maturity	1995 Principal Outstanding Canadian	1995 Principal Outstanding Foreign	1995 Principal Outstanding Total	1995 Weighted Average Interest Rate (percent)	1994 Principal Outstanding Total	1994 Weighted Average Interest Rate (percent)
1995	–		–	–	2,762	
1996	2,546	155	2,701		2,726	
1997	921	478	1,399		1,491	
1998	2,500	683	3,183		3,201	
1999	2,150	–	2,150		2,150	
2000	1,552	–	1,552		–	
1 – 5 years	9,669	1,316	10,985	9.0	12,330	9.3
6 – 10 years	7,815	926	8,741	9.8	9,584	10.1
11 – 15 years	3,340	–	3,340	10.6	2,929	10.2
16 – 20 years	970	2,086	3,056	11.1	3,777	11.3
21 – 25 years	1,075	–	1,075	10.5	–	–
26 years and over	4,198	–	4,198	9.7	4,308	10.1
	27,067	4,328	31,395	9.7	32,928	10.0

9. Long-term debt *(continued)*

As described in note 12, Ontario Hydro has used various derivative financial instruments to hedge the foreign exchange exposure related to long-term debt denominated in foreign currencies. The following table summarizes the currencies in which Ontario Hydro's long-term debt is payable, before and after giving effect to Ontario Hydro's hedging activities:

(millions of dollars)	*1995*		*1994*	
	Principal Outstanding		Principal Outstanding	
	Before Hedging	After Hedging	Before Hedging	After Hedging
Canadian dollars	**27,067**	**27,632**	27,608	29,484
United States dollars	**4,084**	**3,763**	5,088	3,444
Swiss francs	**178**	**–**	161	–
Japanese yen	**66**	**–**	71	–
	31,395	**31,395**	32,928	32,928

Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

Bonds and notes payable in United States dollars include $1,061 million (1994 - $1,091 million) of Ontario Hydro bonds held by the Province of Ontario having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

As described in note 12, Ontario Hydro has used various derivative financial instruments to manage the interest rate risk associated with its outstanding long-term debt.

10. Bank indebtedness

Bank indebtedness includes short-term bank lines of credit which are available to Ontario Hydro in the amount of $600 million (1994 - $600 million), of which $599 million was utilized at year end (1994 – $595 million). The lines of credit are unsecured and bear interest at less than the prime rate.

11. Short-term notes payable *(millions of dollars)*

	1995	*1994*
Short-term notes used for cash management	**520**	265
Short-term notes used for long-term financing	**414**	864
	934	1,129

Certain bond issues were called and refinanced at favourable interest rates by issuing short-term notes. Financial arrangements as described in note 12 were also entered into so as to achieve a fixed interest rate on most of the short-term notes used for long-term financing.

12. Derivative financial instruments *(millions of dollars in stated currency)*

Ontario Hydro has used a variety of derivative financial instruments to manage foreign exchange and interest rate risk. Derivative financial instruments expose Ontario Hydro to credit risk, since there is a risk of counterparty default. This risk is limited to the cost of replacing contracts in which Ontario Hydro has an unrealized gain. Credit risk is monitored and minimized by dealing only with highly rated counterparties. The following table summarizes outstanding positions in derivative financial instruments as at December 31, 1995:

	1995				*1994*	
	Notional Principal Outstanding					
	Maturing in 1996	Maturing beyond 1996	Total	Weighted Average Rate	Notional Principal Outstanding Total	Weighted Average Rate
Foreign exchange risk management instruments:						
Forward exchange contracts						
Purchased forward	**US$67**	**US$188**	**US$255**	**$1.29**	US$568	$1.33
	SF15	**–**	**SF15**	**$1.18**	–	–
Sold forward	**US$52**	**US$129**	**US$181**	**$1.35**	US$182	$1.35
Cross currency swap contracts						
Ontario Hydro receives foreign currency:						
United States dollar	–	**US$56**	**US$56**	**$1.36**[1]	US$656	$1.17[1]
Swiss franc	–	**SF150**	**SF150**	**$1.00**[1]	SF150	$1.00[1]
Japanese yen	–	**¥5,000**	**¥5,000**	**$0.013**[1]	¥5,000	$0.013[1]
[1]contracted rate for exchange of principal						
Foreign currency option combination contracts	–	–	–	–	US$549	n/a
Interest rate risk management instruments:						
Swaption contracts sold						
Ontario Hydro potentially pays fixed	–	**C$1,936**	**C$1,936**	**10.7%**	C$2,199	10.7%
	–	**US$777**	**US$777**	**14.8%**	US$777	14.8%
Interest rate swap contracts						
Ontario Hydro receives fixed	–	**C$3,245**	**C$3,245**	**7.1%**	C$3,115	7.1%
	–	**US$500**	**US$500**	**5.1%**	US$500	5.1%
Ontario Hydro pays fixed	**C$151**	**C$2,292**	**C$2,443**	**8.2%**	C$4,160	6.1%
	–	**US$803**	**US$803**	**6.8%**	US$795	4.9%
Forward rate agreements						
Ontario Hydro pays forward rate	–	–	–	–	C$795	6.2%
	–	–	–	–	US$177	6.0%

Foreign exchange risk management instruments

Forward exchange contracts. Ontario Hydro has entered into forward exchange contracts to purchase US dollars, the majority of which hedge US dollar principal and interest payments on bond issues. In addition, forward exchange contracts were entered into to sell US dollars to hedge some future US dollar revenues.

Cross currency swap contracts. Ontario Hydro has entered into cross currency swap contracts to effectively convert foreign currency principal and interest payments on selected debt issues into Canadian dollars.

Foreign currency option combination contracts. In 1994 Ontario Hydro entered into foreign currency option combination contracts to hedge against the impact of a potential decline in the value of the Canadian dollar in 1995. These contracts provided Ontario Hydro with protection against a decline in the value of the Canadian dollar within a particular range of exchange rates. As a result of these contracts, Ontario Hydro did not benefit from a rise in the value of the Canadian dollar beyond a particular level. There were no contracts outstanding at December 31, 1995.

Interest rate risk management instruments

Swaption contracts. Several of Ontario Hydro's outstanding bond issues are callable by Ontario Hydro at fixed prices on dates before their stated maturities. In 1993 Ontario Hydro converted future potential interest savings related to call options embedded in certain of its bonds to cash, by selling offsetting swaption contracts. These contracts permit holders to require Ontario Hydro to enter into interest rate swaps commencing on the call date. If exercised, the swaptions result in Ontario Hydro making payments based on a fixed interest rate equal to the related bonds' coupon rates, and receiving floating rate payments. Premiums received from the sale of these contracts are being amortized to income, as a reduction of interest expense, over the remaining terms of the related bond issues.

Interest rate swap contracts. As at December 31, 1995, the outstanding receive-fixed interest rate swap contracts have effectively converted fixed interest rates on long-term debt to floating interest rates. These contracts have maturity dates over the period 1997 to 2005 (December 31, 1994 – 1998 to 2004). The outstanding pay-fixed interest rate swap contracts have effectively converted floating interest rates on outstanding debt into fixed interest rates. The majority of the Canadian dollar pay-fixed interest rate swaps mature in 1999, while the US dollar pay-fixed interest rate swaps mature over the period 1997 to 2005 (December 31, 1994 – 1995 to 2002).

Forward rate agreements. In 1994 Ontario Hydro entered into forward rate agreements to hedge against a rise in short-term borrowing rates in early 1995. The agreements effectively fixed Ontario Hydro's interest costs for terms of three months or less beginning in early 1995. There were no agreements outstanding at December 31, 1995.

After giving effect to interest rate derivative financial instruments outstanding as at December 31, 1995, the total amount of long-term debt, bank indebtedness and short-term notes maturing or subject to interest rate resetting in 1996 is approximately $4,557 million. This amount will be affected by treasury activities and the borrowing program in 1996.

13. ACCRUED FIXED ASSET REMOVAL AND USED NUCLEAR FUEL DISPOSAL COSTS *(millions of dollars)*

	1995	*1994*
Accrued fixed asset removal costs		
– accrued decommissioning costs	**764**	621
– accrued fuel channel removal costs	**610**	519
	1,374	1,140
Accrued used nuclear fuel disposal costs	**1,045**	908
	2,419	2,048

Fixed asset removal costs

Fixed asset removal costs are the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives, and the costs of removing certain fuel channels which are expected to be replaced during the life of the nuclear reactors. The significant assumptions used in estimating fixed asset removal costs were:

- decommissioning of nuclear generating stations in the 2042 to 2062 period on a deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;

- dismantlement of Bruce Heavy Water Plants "A", "B" and "D" in the 1994 to 2005 period;
- interest rates through to 2065 ranging from 6% to 10% (1994 – 8% to 10%);
- escalation rates through to 2065 ranging from 1% to 7% (1994 – 2% to 7%); and
- removal of fuel channels in nuclear generating stations during the following periods (1994 comparative in brackets):

Bruce "A" Units 1,3 & 4	2000 to 2008 (1997 to 2007)
Pickering "B"	2009 to 2016 (2009 to 2016)
Bruce "B"	2011 to 2019 (2011 to 2019)
Darlington	2016 to 2024 (2016 to 2024).

The significant assumptions underlying the estimates of fixed asset removal costs are subject to periodic review which could result in changes to these costs, in addition to possible changes in the methods used for decommissioning and fuel channel removal.

Used nuclear fuel disposal costs

The significant assumptions used in estimating the future used nuclear fuel disposal costs were:

- an in-service date of the year 2025 (1994 – 2025) for used nuclear fuel disposal facilities;
- a transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 6% to 9% (1994 – 8% to 10%); and
- escalation rates through to the disposal date ranging from 1% to 7% (1994 – 2% to 7%).

The significant assumptions underlying the estimates of used nuclear fuel disposal costs are subject to periodic review which could result in changes to these costs, in addition to possible changes associated with the technology of disposal.

14. CONTINGENCIES & COMMITMENTS

Manitoba Hydro

In December 1992, due to a projected surplus in generating capacity, Ontario Hydro exercised its right to terminate its long-term power purchase contract with Manitoba Hydro. In Manitoba Hydro's certificate of costs for reimbursement, an amount of $49 million was claimed for costs incurred by Manitoba Hydro prior to entering into the contract with Ontario Hydro on December 7, 1989. Ontario Hydro is of the opinion that costs incurred by Manitoba Hydro before December 7, 1989 are not reimbursable by Ontario Hydro under the contract. As well, based on a review of the certificate of costs, it appears that the total cost claimed by Manitoba Hydro may have been overstated. Ontario Hydro has commenced an action against Manitoba Hydro for a declaration that Ontario Hydro is not obliged to pay costs incurred prior to entering into the contract and for a further judgment against Manitoba Hydro requiring the repayment of amounts which were improperly claimed by Manitoba Hydro and paid by Ontario Hydro under the contract. In July 1994, Manitoba Hydro issued its statement of defence and counterclaim to Ontario Hydro. Manitoba Hydro claims that they are entitled to an immediate payment from Ontario Hydro of $55 million, representing the claim for costs incurred by Manitoba Hydro prior to entering into the contract, plus interest. At this time, the outcome of these claims are not determinable, and as such, no provision has been accrued in Ontario Hydro's financial statements with respect to any amounts in dispute.

Power Purchase Agreements

Ontario Hydro purchases a portion of its electricity requirements pursuant to long-term contractual power purchase agreements (PPAs) with various independent power producers. The PPAs, representing in-service capacity of approximately 1,050 MW as at December 31, 1995, expire on various dates from 1999 to 2045. The obligations to purchase power under these contracts over the next 20 years have a total net present value of approximately $5,800 million with estimated payments over the next five years, in dollars of the year, as follows: 1996 – $470 million; 1997 – $640 million; 1998 – $650 million; 1999 – $670 million; and 2000 – $680 million.

Deliveries in the aggregate account for approximately 5.2 percent of Ontario Hydro's 1995 electric energy requirements (1994 - 3.7 percent). The amount of energy received and the total payments made under these agreements were:

14. CONTINGENCIES AND COMMITMENTS *(continued)*	*1995*	*1994*
Gigawatt-hours received	**7,565**	5,442
Power purchase payments *(millions of dollars)*	**418**	303

Loan Guarantees
Ontario Hydro is contingently liable under guarantees given to third party lenders who have provided long-term financing to certain independent power producers. These guarantees total approximately $193 million as at December 31, 1995.

15. RETAINED EARNINGS *(millions of dollars)*

	1995	*1994*
Balance at beginning of year	**3,912**	3,325
Net income	**628**	587
Balance at end of year	**4,540**	3,912

The balance in this account is retained for purposes prescribed under the Power Corporation Act.

16. CONSOLIDATED STATEMENT OF CHANGES IN CASH POSITION

Cash position is defined to be cash and short-term investments less bank indebtedness and short-term notes used for cash management.

Cash position is comprised of the following:

(millions of dollars)	*1995*	*1994*
Bank indebtedness	**(604)**	(603)
Short-term notes used for cash management (note 11)	**(520)**	(265)
	(1,124)	(868)

The changes in non-cash working capital and long-term accounts payable affecting operations consisted of the following:

(millions of dollars)	*1995*	*1994*
Accounts receivable – decrease (increase)	**138**	(75)
Fuel for electric generation, materials and supplies – decrease	**143**	143
Accounts payable and accrued charges – (decrease)	**(248)**	(18)
Accrued interest – (decrease)	**(12)**	(88)
Long-term accounts payable and accrued charges – (decrease) increase	**(1)**	46
	20	8

17. BENEFIT PLANS

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan, the long-term disability plan and the group health care plan.

Pension plan

Pension costs for 1995 were $74 million (1994 – $76 million). In 1995, $59 million (1994 – $50 million) of the pension costs were charged to operations and $15 million (1994 – $26 million) were capitalized as part of the cost of fixed assets.

The actuarial present value of the accrued pension benefits is estimated to be $6,290 million as at December 31, 1995 (1994 – $5,700 million), and the pension plan assets available for these benefits were $7,790 million (1994 – $6,791 million) based on current fair values.

The actuarial present value of the accrued pension benefits was determined for accounting purposes using the following significant assumptions which reflect management's best estimate and take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits – 7.75% (1994 – 8.00%);
- salary escalation rate – 3.00% (1994 – 3.00%) plus an age and service dependent increase in respect of promotion, progression and merit;
- average long-term rate used to estimate improvements in pension benefits to partially offset the effect of increase in cost of living – 2.06% (1994 – 1.69%); and
- average remaining service period of employees – 16 years (1994 – 17 years).

Deferred pension costs on the statement of financial position represent the cumulative difference between the funding contributions, including special payments, and pension costs. As at December 31, 1995, the deferred pension costs amounted to $149 million (1994 – $169 million) and primarily reflect special payments made in 1990 and 1991 relating to past service benefit improvements offset by costs associated with the 1993 voluntary staff reduction program. The costs of pension benefit improvements funded by the special payments are being amortized as a charge to pension costs on a straight-line basis over the average remaining service period of employees.

Long-term disability plan

The long-term disability plan is entirely funded by Ontario Hydro. For 1995 contributions to the plan amounted to $10 million (1994 – $4 million).

Group life insurance plan

Ontario Hydro paid $6 million (1994 – $3 million) in premiums for basic insurance coverage for employees. Premiums for additional coverage, if requested, are paid for by the employee.

Group health care plan

Ontario Hydro provides a group health care plan to its employees. In 1995, the cost of providing these benefits was $55 million (1994 – $61 million).

Other post-retirement benefits

In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as the benefits are paid. In 1995, the cost of providing these benefits was $21 million (1994 – $19 million).

18. RESEARCH AND DEVELOPMENT

In 1995, approximately $73 million of research and development costs were charged to operations, $9 million were capitalized and $35 million were charged to accrued provisions (1994 – $128 million, $14 million and $23 million, respectively).

19. COMPARATIVE FIGURES

Certain of the 1994 comparative figures in the financial statements have been reclassified to conform with the 1995 financial statement presentation.

Five-Year Summary of Financial and Operating Statistics

(millions of dollars)

	1995	1994	1993	1992	1991
Revenues					
Primary power and energy					
Municipal utilities	**5,899**	5,829	5,721	5,281	4,873
Retail customers	**1,635**	1,688	1,641	1,568	1,397
Direct industrial customers	**914**	866	873	863	811
	8,448	8,383	8,235	7,712	7,081
Secondary power and energy	**233**	349	128	56	62
Other revenues	**315**	264	112	104	96
	8,996	8,996	8,475	7,872	7,239
Costs					
Operation, maintenance and administration[1]	**1,931**	1,935	2,164	2,338	2,118
Fuel used for electric generation[1]	**592**	586	919	1,149	1,137
Power purchased	**495**	341	260	186	151
Provincial government levies	**283**	284	286	270	252
Depreciation and amortization	**1,640**	1,595	1,506	1,198	1,136
	4,941	4,741	5,135	5,141	4,794
Income before financing charges	**4,055**	4,255	3,340	2,731	2,445
Financing charges					
Gross interest	**3,574**	3,544	3,849	3,782	3,586
Capitalized interest	**(78)**	(123)	(462)	(1,231)	(1,194)
Investment income	**(123)**	(63)	(65)	(119)	(158)
Foreign exchange	**54**	42	8	(13)	7
	3,427	3,400	3,330	2,419	2,241
Income before restructuring charge	**628**	855	10	312	204
Corporate restructuring charge and writeoffs	**–**	268	3,614	–	–
Net income (loss)	**628**	587	(3,604)	312	204
Financial position					
Total assets	**42,984**	44,100	44,706	46,671	43,244
Fixed assets	**39,299**	39,907	40,740	40,690	38,170
Long-term debt[2]	**31,430**	32,967	33,685	34,034	32,160
Equity	**4,540**	3,912	3,325	6,931	6,619
Cash flows					
Cash provided from operating activities	**2,479**	2,256	1,332	1,691	1,381
Cash provided from (used for) financing activities	**(1,941)**	(1,245)	404	1,784	2,743
Cash used for investment in fixed assets	**932**	1,089	1,871	3,375	3,356
Investment in fixed assets	**881**	1,164	2,296	3,527	3,934

	1995	1994	1993	1992	1991
Financial indicators					
Interest coverage – before restructuring charge[3]	**1.19**	1.25	1.00	1.09	1.06
Interest coverage – after restructuring charge[3]	–	1.17	0.04	–	–
Debt ratio[4]	**0.886**	0.904	0.918	0.841	0.838
Energy sales[5] *millions of kilowatt-hours*					
Primary energy sales					
Municipal utilities	**94,606**	93,405	92,093	91,317	93,623
Retail customers	**18,390**	18,499	18,519	18,938	18,988
Direct industrial customers	**18,651**	17,552	17,415	18,094	18,353
	131,647	129,456	128,027	128,349	130,964
Secondary energy sales[6]	**9,203**	12,628	4,807	1,896	2,123
	140,850	142,084	132,834	130,245	133,087
Energy and Demand					
In-service capacity *megawatts*[6]	**29,244**	30,135	31,851	31,309	31,123
December primary peak demand *megawatts*	**22,613**	21,849	20,506	21,339	22,933
Primary energy made available *millions of kilowatt-hours*[7]	**137,038**	134,874	133,769	134,376	136,966
Number of primary customers[5]					
Municipal utilities	**306**	306	309	311	311
Retail customers	**962,426**	954,502	942,812	940,617	925,641
Direct industrial customers	**103**	103	104	107	109
Average revenue[5] *in cents per kilowatt-hour of total energy sales*					
Primary power and energy					
Municipal utilities	**6.235**	6.241	6.212	5.783	5.205
Retail customers	**9.376**	9.684	9.265	8.884	7.883
Direct industrial customers	**4.901**	4.934	5.013	4.770	4.419
All primary customers combined	**6.464**	6.529	6.473	6.070	5.459
Secondary power and energy	**2.532**	2.764	2.663	2.954	2.920
All classifications combined	**6.205**	6.192	6.334	6.024	5.419
Average rate increases (decreases) *expressed as a per cent*					
Municipal utilities	**0.0**	0.0	8.2	11.8	8.7
Retail customers	**0.0**	0.0	6.5	11.8	8.7
Direct industrial customers	**(0.7)**	0.0	8.2	11.8	7.8
All primary customers combined	**(0.1)**	0.0	7.9	11.8	8.6

	1995	*1994*	*1993*	*1992*	*1991*
Average cost[1,8] *in cents per kilowatt-hour of energy generated*					
Hydroelectric					
Operation, maintenance and administration	**.305**	.318	.277	.280	.299
Water rentals	**.344**	.336	.330	.317	.338
Depreciation, debt guarantee fee and financing charges	**.416**	.543	.488	.454	.424
Other revenues	**(.003)**	(.011)	–	–	–
	1.062	1.186	1.095	1.051	1.061
Nuclear					
Operation, maintenance and administration	**1.077**	1.066	1.026	1.236	1.033
Uranium	**.255**	.270	.514	.515	.502
Depreciation, debt guarantee fee and financing charges	**3.884**	3.529	3.910	3.080	2.756
Other revenues	**(.103)**	(.118)	(.009)	(.008)	–
	5.113	4.747	5.441	4.823	4.291
Fossil					
Operation, maintenance and administration	**1.201**	1.331	1.311	.989	.863
Coal, gas and oil	**2.394**	2.378	2.515	2.426	2.388
Depreciation, debt guarantee fee and financing charges	**3.228**	3.732	3.022	1.648	1.492
Other revenues	**(.121)**	(.020)	(.007)	(.029)	(.024)
	6.702	7.421	6.841	5.034	4.719
Average number of employees					
Regular	**21,505**	22,525	26,442	28,835	28,396
Non-regular[9]	**1,573**	2,082	3,331	6,004	7,309

1. Operations, maintenance and administration and fuel costs have been restated to exclude other revenues.

2. Long-term debt includes long-term debt payable within one year.

3. Interest coverage represents net income plus interest on bonds, notes, and other debt divided by interest on bonds, notes and other debt.

4. Debt ratio represents debt (bonds and notes payable, short-term notes payable, other long-term debt, unamortized swaption premiums, accrued fixed asset removal and used nuclear fuel disposal costs and bank lines of credit less unamortized foreign exchange gains and losses) divided by debt plus equity.

5. Figures for 1995 are preliminary.

6. In-service capacity represents the net output power supplied by all generating units, net firm power purchase contracts and purchases from non-utility generators. Excluded are non-operating reserve facilities of: 1995 – 5,043 MW; 1994 – 4,297 MW; 1993 – 2,686 MW; 1992 – 1,554 MW; and 1991 – 1,546 MW.

7. Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.

8. Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.

9. The majority of non-regular staff are construction trades persons.

Customers served by Ontario Hydro and associated municipal utilities	*1995*[1]	*1994*	*1993*	*1992*	*1991*
Total number of customers *in thousands*					
Residential	**3,301**	3,293	3,252	3,205	3,163
Farm	**103**	103	103	104	105
Commercial and industrial	**438**	437	436	430	428
	3,842	3,833	3,791	3,739	3,696
Average annual use *in kilowatt-hours per customer*					
Residential	**10,525**	10,763	10,965	11,024	11,581
Farm	**22,432**	23,138	23,660	23,496	23,945
Commercial and industrial	**205,234**	201,265	198,841	201,112	205,982
Average revenue[2] *in cents per kilowatt-hour*					
Residential	**8.90**	8.83	8.77	8.12	7.23
Farm	**9.16**	8.93	8.82	8.19	7.34
Commercial and industrial	**6.48**	6.75	6.76	6.31	5.70
All customers	**7.19**	7.37	7.38	6.86	6.16

1. Figures for 1995 are preliminary.
2. Includes rural rate assistance.

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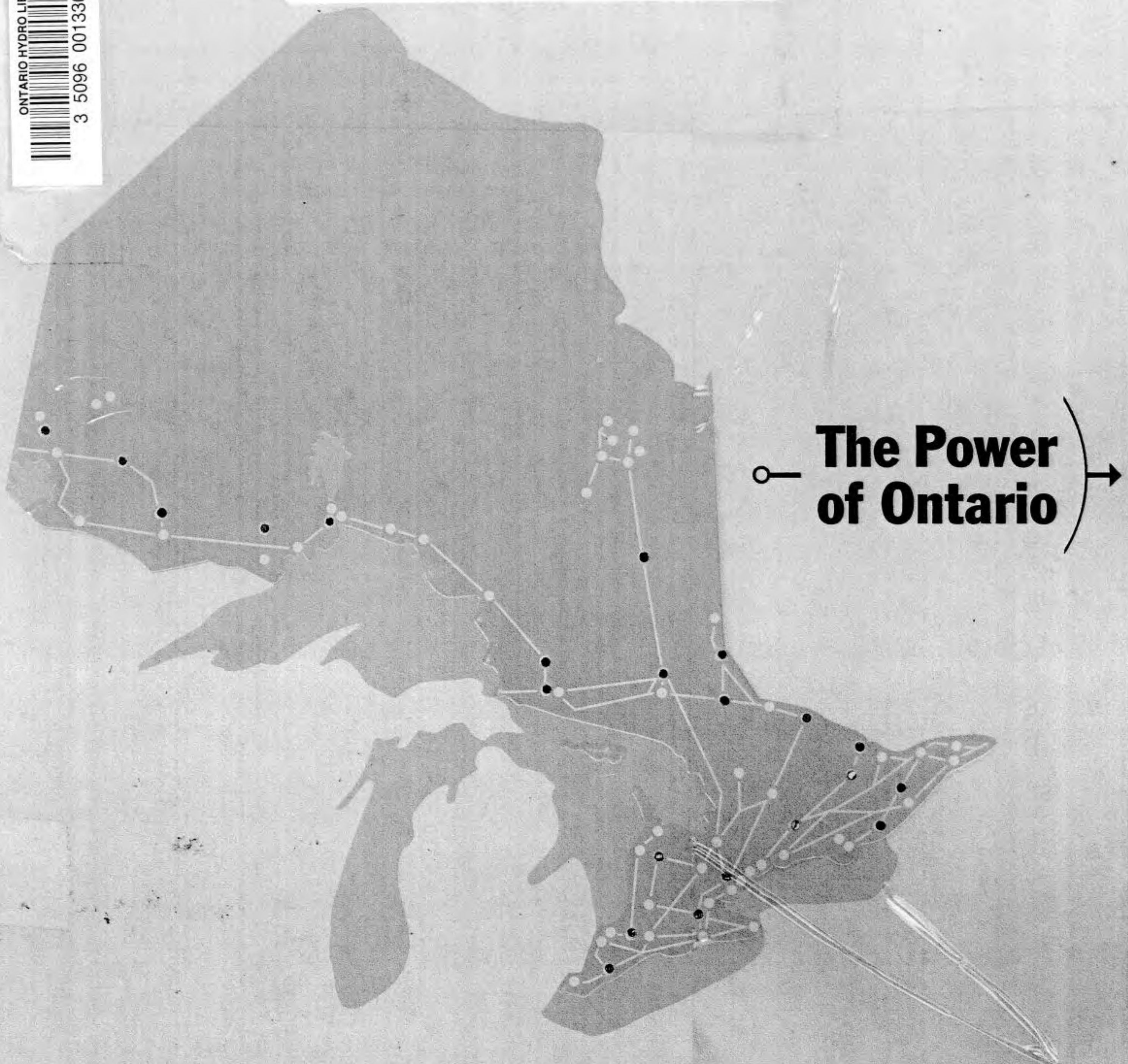

The Power of Ontario

Consolidated Statement of Operations

for the year ended December 31 (millions of dollars)

	1996	1995
Revenues		
Primary power and energy		
Municipal utilities	**5,857**	5,899
Retail customers	**1,647**	1,635
Direct industrial customers	**903**	914
	8,407	8,448
Secondary power and energy (note 2)	**172**	233
Other revenues	**307**	315
	8,886	8,996
Costs		
Operation, maintenance and administration	**2,008**	1,916
Fuel used for electric generation	**615**	607
Power purchased	**571**	495
Provincial government levies (note 3)	**282**	283
Depreciation and amortization (note 4)	**1,656**	1,640
	5,132	4,941
Income before financing charges and corporate write-offs	**3,754**	4,055
Financing charges (note 5)	**3,182**	3,427
Income before corporate write-offs	**572**	628
Corporate write-offs (note 6)	**2,560**	–
Net (loss) income	**(1,988)**	628

See accompanying notes to financial statements.

Consolidated Statement of Financial Position

as at December 31 (millions of dollars)

Assets	**1996**	1995
Fixed assets (note 7)		
Fixed assets in service	**49,266**	50,485
Less accumulated depreciation	**13,608**	12,662
	35,658	37,823
Construction in progress	**1,160**	1,476
	36,818	39,299
Current assets		
Accounts receivable	**1,082**	1,144
Fuel for electric generation (note 8)	**368**	377
Materials and supplies, at cost	**311**	282
	1,761	1,803
Other assets		
Deferred debt costs	**779**	840
Deferred pension costs (note 17)	**131**	149
Deferred demand management costs, net of accumulated amortization (note 6)	**–**	411
Long-term accounts receivable and other assets	**381**	482
	1,291	1,882
	39,870	42,984

See accompanying notes to financial statements.

LIABILITIES	1996	1995
Long-term debt (note 9)	**28,588**	28,726
Current liabilities		
Bank indebtedness (note 10)	**644**	604
Accounts payable and accrued charges	**1,025**	1,007
Short-term notes payable	**1,091**	934
Accrued interest	**772**	879
Long-term debt payable within one year (note 9)	**1,482**	2,704
	5,014	6,128
Other liabilities		
Unamortized swaption premiums (note 11)	**308**	657
Long-term accounts payable and accrued charges	**807**	514
Accrued fixed asset removal and used nuclear fuel disposal costs (note 13)	**2,601**	2,419
	3,716	3,590
CONTINGENCIES & COMMITMENTS (notes 11 & 14)		
EQUITY		
Retained earnings (note 15)	**2,552**	4,540
	39,870	42,984

On behalf of the Board,

Chairman, Board of Directors

President & Chief Executive Officer

Toronto, Canada,
February 18, 1997

Consolidated Statement of Changes in Cash Position

for the year ended December 31
(millions of dollars)

	1996	1995
Operating activities		
Net (loss) income	**(1,988)**	628
Adjust for non-cash items		
Depreciation and amortization	**1,656**	1,640
Corporate write-offs	**2,560**	–
Amortization of foreign exchange gains and losses	**57**	55
Provision for used nuclear fuel disposal costs	**59**	73
Other	**(30)**	63
	2,314	2,459
Change in non-cash balances related to operations (note 16)	**(86)**	20
	2,228	2,479
Financing activities		
Debt for long-term financing		
Issued	**2,417**	2,494
Retired	**(5,324)**	(2,951)
	(2,907)	(457)
Redemption of debt for long-term financing, net of reissuances	**1,732**	(1,229)
Cash paid on settlement of swaptions	**(358)**	–
	(1,533)	(1,686)
Investing activities		
Fixed assets	**(868)**	(932)
Other assets	**133**	138
	(735)	(794)
Change in cash position during the year	**(40)**	(1)
Bank indebtedness at beginning of year	**(604)**	(603)
Bank indebtedness at end of year (note 10)	**(644)**	(604)

See accompanying notes to financial statements.

Notes to Financial Statements

1. Summary of Significant Accounting Policies

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in Canada, applied on a basis consistent with that of the preceding year. The significant accounting policies followed by Ontario Hydro are described below.

a) Rate setting

Ontario Hydro has broad powers to generate, supply and deliver electric power throughout the Province of Ontario. The Corporation operates under the Power Corporation Act and is subject to the provisions of the Ontario Energy Board Act.

Under the provisions of the Power Corporation Act, the price payable by municipal and other customers for power is the cost of supplying the power. Such cost is defined in the Act to include the cost of operating and maintaining the system, the cost of energy conservation programs, depreciation, interest, and the annual amounts for debt retirement and stabilization of rates and contingencies. The annual amounts for debt retirement and stabilization of rates and contingencies are accounted for as net income.

Under the provisions of the Ontario Energy Board Act, a public hearing before the Ontario Energy Board is required to review any changes in electricity rates proposed by Ontario Hydro which affect its municipal utilities, direct industrial customers, or, if the Minister of Energy so directs, rural retail customers. The Ontario Energy Board then submits its recommendations to the Minister of Environment and Energy. After considering the recommendations of the Ontario Energy Board, Ontario Hydro's Board of Directors, under the authority of the Power Corporation Act, establishes the electricity rates to be charged to customers.

The Board of Directors may specify that an amount related to an item be included in electricity rates of a period which differs from the period in which it would be recognized under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment. If so, the accounting treatment given the item is the same as its treatment for rate-setting purposes. This authority of the Board of Directors may be used in respect of a specific transaction or an accounting policy.

Ontario Hydro's accounting policies relating to discounts and premiums arising from the acquisition of debt prior to maturity and foreign exchange gains and losses on United States dollar-denominated short-term financing replacing United States dollar-denominated long-term debt which has been redeemed prior to maturity, reflect the rate-setting treatment of these items as specified by the Board of Directors. Under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment, these amounts would be included as gains or losses of the current period. The Board of Directors has used its rate-setting authority to specify that costs of the rehabilitation program for steam generators at Pickering "A" and "B" and Bruce "A" Nuclear Generating Stations shall be deferred for recovery in future periods. Under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment, these costs would be expensed as incurred. The Board of Directors has also used its rate-setting authority to specify that the nuclear recovery expenditures planned to be incurred over the period 1997 to 2001 shall be charged to operations in 1996. Under generally accepted accounting principles for enterprises operating in a non-rate-regulated environment, these costs would be expensed as incurred.

b) Consolidation

The consolidated financial statements include the financial statements of Ontario Hydro and its wholly-owned subsidiaries Ontario Hydro International Inc. (OHI Inc.) and Ontario Hydro Interconnected Markets Inc. (OHIM Inc.). OHI Inc. was incorporated under the Ontario Business Corporations Act and was established as a subsidiary of Ontario Hydro in September 1993. OHIM Inc. was incorporated on July 9, 1996 under the General Corporation Law of the State of Delaware in the United States. Both OHI Inc. and OHIM Inc. publish separate financial statements.

c) Fixed assets

Fixed assets in service include operating facilities and non-operating reserve facilities, and heavy water held for use in nuclear generating stations. Construction in progress includes fixed assets under construction.

Fixed assets are capitalized at cost which comprises material, labour, engineering costs, overheads, depreciation on service equipment, interest applicable to capital construction activities, and for new facilities, the costs of training initial operating staff. In the case of generating facilities, the cost also includes the net cost of commissioning which comprises the cost of start-up less the value attributed to energy produced by generation facilities during their commissioning period. For multi-unit facilities, a proportionate share of the cost of common facilities is placed in service with each major operating unit. The cost of heavy water comprises the direct cost of production and applicable overheads, as well as interest and depreciation on the heavy water production facilities and the estimated removal costs of these facilities. Leases which transfer the benefits and risks of ownership of assets to Ontario Hydro are capitalized.

Interest is capitalized on construction in progress at rates (1996 - 9.9 per cent; 1995 - 10.1 per cent) which approximate the average cost of all long-term funds borrowed. If the construction period of a project is extended and the construction activities are continued, interest is capitalized during the period of extension provided that the project has a reasonable expectation of being completed.

If a project is deferred as a result of a management decision and there is a reasonable expectation of completion, interest capitalization ceases and amortization for any loss in value commences.

If a project is cancelled or deferred indefinitely with a low probability of resuming construction, all costs, including the costs of cancellation, are written off to operations.

If fixed assets are removed from operations and mothballed for future use, the costs of mothballing are charged to operations. These assets are classified as non-operating reserve facilities.

d) Depreciation

The capital costs of fixed assets in service are depreciated on a straight-line basis, with the exception of heavy water held to replace losses occurring during the operation of Ontario Hydro's nuclear generating stations. Heavy water held for this purpose is depreciated on a sinking fund basis over the period through to the first year heavy water from an out-of-service nuclear station is estimated to be available for replacement purposes.

Depreciation rates for the various classes of assets are based on their estimated service lives. Major components of fossil and nuclear generating stations are depreciated over the lesser of the service life expectancy of the major component or the remaining service life of the associated generating station; for hydroelectric generating stations, major components are depreciated over the service life expectancy of the component, ranging from 25 to 100 years. Heavy water in nuclear generating stations is depreciated over the remaining service life of the associated station. The estimated service lives of assets in the major classes are:

Generating stations	– fossil	– 40 years
	– nuclear	– 40 years
Transmission and distribution facilities		– 10 to 100 years
Administration and service facilities		– 5 to 50 years

In accordance with group depreciation practices, for normal retirements the cost of fixed assets retired is charged to accumulated depreciation with no gain or loss reflected in operations. However, gains and losses on sales of fixed assets and losses on premature retirements are charged to operations in the year incurred as adjustments to depreciation expense.

When the costs of removal less residual value on retirements of fixed assets can be reasonably estimated and are significant, provisions for these costs are charged to depreciation expense on an annuity basis over the remaining service life of the related fixed assets. Removal costs that are provided for include the estimated costs of decommissioning nuclear and fossil stations and the estimated costs of removing certain nuclear reactor fuel channels. Other removal costs are charged to depreciation expense as incurred.

The estimated service lives of fixed assets and the significant assumptions underlying the estimates of fixed asset removal costs are subject to periodic review. Any changes arising out of such a review are implemented on a remaining service life basis from the year the changes can first be reflected in electricity prices.

Non-operating reserve facilities are amortized so that any estimated loss in value is charged to depreciation expense on a straight-line basis over their expected non-operating period.

e) Heavy water sales

Ontario Hydro has produced sufficient quantities of heavy water to meet future needs of its existing nuclear generating stations and is now producing heavy water for sales to external parties. Revenues from external sales contracts requiring the production of heavy water far in advance of delivery dates are recognized on a percentage-of-completion basis and revenues from all other heavy water sales are recognized at the point of sale. Resulting profits or losses are credited or charged to operations in the year incurred.

f) Fuel for electric generation

Fuel used for electric generation comprises the average inventory costs of fuel consumed less the value attributed to commissioning energy produced, plus provisions for disposal of nuclear fuel used during the period. The inventory cost of fuel comprises fuel purchases, transportation and handling costs.

The costs for disposal of nuclear fuel used in each period are charged to operations based on estimated future expenditures and interest accumulating to the estimated date of disposal. Estimates of expenditures, interest and escalation rates, and the date of disposal are subject to periodic review. Adjustments resulting from changes in estimates are charged to operations on an annuity basis over the period from the year the changes can first be reflected in electricity prices to the estimated in-service date of the disposal facility.

g) Foreign currency translation

Current monetary assets and liabilities in foreign currencies are translated to Canadian currency at year-end rates of exchange and the resultant exchange gains or losses are credited or charged to operations. Long-term debt payable in foreign currencies is translated to Canadian currency at year-end rates of exchange. Resulting unrealized exchange gains or losses are deferred and included in deferred debt costs, and are amortized to operations on an annuity basis over the remaining life of the related debt.

Foreign exchange gains or losses on hedges of long-term debt payable in foreign currencies are deferred and included in deferred debt costs. The deferred gains or losses on hedges are amortized to operations on an annuity basis in the periods the hedges provide benefit.

Foreign exchange gains or losses on early redemption of long-term debt, including subsequent gains and losses on short-term replacement financing, are deferred and included in deferred debt costs if the exposure in the foreign currency related to the redeemed debt is continued by refinancing the redeemed debt in the same currency. These deferred gains or losses are amortized on an annuity basis over the period to the original maturity date of the redeemed debt. If the foreign currency exposure is reduced as a result of the early redemption of debt, the resulting foreign exchange gains or losses related to the redeemed debt are credited or charged to operations.

h) Deferred debt costs

Deferred debt costs include the unamortized amounts related to unrealized foreign exchange gains or losses resulting from the translation of foreign currency long-term debt; deferred foreign exchange gains or losses on hedges; deferred foreign exchange gains or losses on the early redemption of long-term debt; discounts or premiums arising from the issuance of debt or the acquisition of debt prior to maturity; discounts or premiums accrued on foreign currency hedges; and net unamortized premiums on settled, exercised or expired swaption contracts.

Discounts or premiums arising from the issuance of debt are amortized over the period to maturity of the debt on an annuity basis when the term of the debt exceeds one year and on a straight-line basis when the term is one year or less. Discounts or premiums on debt acquired prior to the date of maturity are amortized on an annuity basis over the period from the acquisition date to the original maturity date of the debt. Discounts or premiums on foreign currency hedges are credited or charged to operations on an annuity basis over the terms of the individual hedges. Net unamortized premiums on settled, exercised or expired swaption contracts are amortized on an annuity basis over the period from the settlement, exercise or expiry date to the original maturity date of the related debt.

1. Summary of Significant Accounting Policies *(continued)*

i) Demand management

Demand management activities undertaken by Ontario Hydro encourage customers to conserve or use electricity more efficiently as an alternative to more expensive generation or to address transmission limitations. Given an expected future move away from the existing rate-regulated, monopoly operating environment toward a more commercial operating environment for Ontario Hydro's generation-related business, Ontario Hydro has implemented an accounting policy change, effective January 1, 1997, whereby generation-related demand management expenditures will be charged to operations as incurred. Transmission-related demand management costs that have reasonably assured and specifically identifiable future benefits to Ontario Hydro will continue to be deferred and amortized to operations on a straight-line basis over the periods that benefit. All other costs are charged to operations as incurred. The benefit periods of deferred demand management costs are subject to periodic review which could result in changes. Any changes arising out of such a review are implemented on a remaining benefit period basis from the year the changes can first be reflected in electricity prices.

j) Pension plan

The pension plan is a contributory, defined benefit plan covering all regular employees of Ontario Hydro. Pension costs for accounting purposes are actuarially determined using the projected benefit method prorated on services and based on assumptions that reflect management's best estimate of the effect of future events on the actuarial present value of accrued pension benefits. Pension plan assets are valued using current fair values and pension plan adjustments are amortized on a straight-line basis over the expected average remaining period of service of the employees covered by the Ontario Hydro pension plan.

k) Other post-employment benefits

In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. As well, Ontario Hydro provides long-term disability benefits to qualifying employees during extended absences from work due to sickness or injury.

Effective January 1, 1997, Ontario Hydro will implement accrual accounting for other post-employment benefits in anticipation of new recommendations from the Canadian Institute of Chartered Accountants, whereby the expected costs of providing those benefits will be charged to operations as employees render services. Accordingly, the costs of other post-employment benefits will be actuarially determined for accounting purposes based on assumptions that reflect management's best estimates of the effect of future events on the actuarial present value of the accrued benefits. The transition obligation which arises on conversion to accrual accounting will be charged to retained earnings on January 1, 1997 (see note 15). Prior to January 1, 1997, the costs of other post-employment benefits were charged to operations as the benefits were paid.

l) Research and development

Research and development (R&D) costs are charged to operations in the year incurred, except for: R&D costs related directly to the design or construction of a specific capital facility, which are capitalized as part of the cost of the facility; and R&D costs incurred to discharge long-term obligations, and for which specific provision has already been made, which are charged to the appropriate accumulated provision.

2. Secondary Power and Energy

Secondary power and energy revenues include $152 million (1995 - $231 million) from sales of electricity to United States utilities.

3. Provincial Government Levies (millions of dollars)

	1996	1995
Provincial water rentals	**120**	113
Provincial debt guarantee fee	**162**	170
	282	283

Provincial water rentals are the amounts paid to the Province of Ontario for the use of water for hydroelectric generation. The Province of Ontario has legislated that Ontario Hydro pay to the Province an annual debt guarantee fee of one-half of one per cent on the total debt guaranteed by the Province, outstanding as of the preceding December 31.

4. Depreciation and Amortization (millions of dollars)

	1996	1995
Depreciation of fixed assets in service	**1,465**	1,458
Amortization of deferred demand management costs	**35**	31
Fixed asset removal costs	**89**	98
Other removal costs	**67**	53
	1,656	1,640

5. Financing Charges (millions of dollars)

	1996	1995
Interest on bonds, notes and other debt – long-term	**2,895**	3,227
– short-term	**141**	149
Interest on accrued fixed asset removal and used nuclear fuel disposal costs	**170**	198
	3,206	3,574
Less:		
Interest charged to – construction in progress	**52**	74
– fuel for electric generation	**2**	4
Interest earned on investments	**52**	123
	106	201
Interest charged to operations	**3,100**	3,373
Foreign exchange	**82**	54
	3,182	3,427

6. Corporate Write-Offs (millions of dollars)

	1996
Future Use Heavy Water	**1,203**
Nuclear Recovery Expenditures	**400**
Deferred Demand Management Expenditures	**398**
Mattagami Development	**282**
Bruce Nuclear Generating Station "A", Unit 1	**277**
	2,560

In December 1996, the Board of Directors of Ontario Hydro approved a number of operational decisions in light of future uncertainties, such as possible changes in the volume of electricity sales and energy production plans. The decisions resulted in a number of charges and write-offs to net income in 1996.

Given the early shutdown of Bruce Unit 2 in 1995 and the planned shutdown of Unit 1 in the year 2000, Hydro has sufficient heavy water available from these units to meet loss replacement requirements of other in-service units until additional heavy water becomes available at the completion of the service life of Pickering Nuclear Generating Station "A". Therefore, Hydro's existing supply of heavy water, held to replace losses, has been written off based on the December 31, 1996 expiration of its service life.

Hydro has embarked on a program to ensure that adequate nuclear recovery plan expenditures are made in future years to allow for the achievement of its Nuclear Excellence Strategy. Costs of the program, which are planned to be incurred over the period 1997 to 2001, have been accrued and charged to 1996 operations as approved by the Board of Directors under its rate-setting authority.

Effective January 1, 1997, Ontario Hydro changed its accounting for demand management expenditures such that generation-related demand management expenditures will no longer be deferred and amortized. As such, deferred generation-related demand management expenditures have been written off as at December 31, 1996.

In 1991, Ontario Hydro purchased the Smoky Falls Generating Station and the rights for future development along the Mattagami River. Work on Hydro's capital project involving development on the Mattagami has been deferred since January 1996 pending a decision on whether or not to proceed. Ontario Hydro has decided to limit the scope of the Mattagami redevelopment to Smoky Falls, rather than pursue the full expansion of the Mattagami plants, resulting in a partial write-off of the construction in progress costs related to this project.

Bruce Nuclear Generating Station "A" Unit 1 will be laid up in April of the year 2000. The Bruce Unit 1 loss includes the write-off of related capital amounts, accrual of staff reduction expenditures and adjustment of decommissioning provisions.

7. Fixed Assets (millions of dollars)

1996

	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress
Generating stations – hydroelectric	**2,546**	**837**	**347**
– fossil	**5,360**	**2,460**	**41**
– nuclear	**24,430**	**5,340**	**431**
Heavy water	**4,014**	**755**	**–**
Transmission and distribution facilities	**11,123**	**3,219**	**304**
Administration and service facilities	**1,793**	**997**	**37**
	49,266	**13,608**	**1,160**

1995

	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress
Generating stations – hydroelectric	2,512	832	624
– fossil	5,442	2,287	42
– nuclear	24,738	4,873	490
Heavy water	5,346	781	–
Transmission and distribution facilities	10,611	2,890	300
Administration and service facilities	1,836	999	20
	50,485	12,662	1,476

Pickering relicensing
In December 1996, the Atomic Energy Control Board granted a six-month renewal of the current license at the Pickering Nuclear Generating Station, after which time a number of performance factors will be reassessed. Management has committed to making the necessary Nuclear Recovery Plan expenditures at Pickering Nuclear Generating Station (note 6).

Nuclear steam generator rehabilitation costs
Ontario Hydro has undertaken a major program to rehabilitate steam generators at Pickering "A" and "B" and Bruce "A" Nuclear Generating Stations. The costs of the program, which will continue until 2001, are being deferred and amortized over the remaining service lives of the individual generators commencing as each generator is returned to service. As at December 31, 1996, deferred nuclear steam generator rehabilitation costs included in nuclear generating station construction in progress and fixed assets in service are $135 million and $120 million respectively (1995 - $125 million and $nil, respectively). Accumulated depreciation related to the in-service balance amounts to $1 million as at December 31, 1996 (1995 - $nil).

8. Fuel for Electric Generation (millions of dollars)

		1996	1995
Inventories	– uranium	136	111
	– coal	205	225
	– oil	27	41
		368	377

9. Long-Term Debt (millions of dollars)

	1996	1995
Bonds and notes payable	30,037	31,395
Other long-term debt	33	35
	30,070	31,430
Less payable within one year	1,482	2,704
	28,588	28,726

Bonds and notes payable, expressed in Canadian dollars, are summarized by years of maturity in the following table:

(millions of dollars)

	1996				1995	
	Principal Outstanding			Weighted Average Interest Rate (per cent)	Principal Outstanding Total	Weighted Average Interest Rate (per cent)
Years of Maturity	Canadian	Foreign	Total			
1996	-	-	-		2,701	
1997	1,000	479	1,479		1,399	
1998	2,500	782	3,282		3,183	
1999	2,050	590	2,640		2,150	
2000	1,552	-	1,552		1,552	
2001	1,540	838	2,378			
1 - 5 years	8,642	2,689	11,331	9.0	10,985	9.3
6 - 10 years	6,509	59	6,568	9.6	8,741	9.8
11 - 15 years	3,365	82	3,447	10.7	3,340	10.8
16 - 20 years	648	1,660	2,308	10.0	3,056	11.2
21 - 25 years	2,675	-	2,675	10.5	1,075	10.7
26 years and over	3,708	-	3,708	9.1	4,198	9.8
	25,547	4,490	30,037	9.5	31,395	9.9

9. Long-Term Debt *(continued)*

The weighted average interest rate represents the effective rate of interest on fixed-rate bonds and notes and the current interest rate in effect at December 31 for floating-rate bonds and notes, all before considering the effect of derivative financial instruments used to manage interest rate risk. Bonds and notes payable are either held, or guaranteed as to principal and interest, by the Province of Ontario.

Bonds and notes payable in United States dollars include $633 million (1995 - $1,061 million) of Ontario Hydro bonds held by the Province of Ontario having terms identical with Province of Ontario issues sold in the United States on behalf of Ontario Hydro.

Bonds and notes payable include Canadian $3,633 million and US $522 million of bonds callable by Ontario Hydro at fixed prices on dates before their stated maturities (1995 - Canadian $3,730 million and US $777 million). The callable bonds have stated maturities over the period 2001 to 2013 and have a weighted average coupon rate of 11.6% (1995 - 12.1%). The bonds are callable by Ontario Hydro at a weighted average call price equal to 101% of the bonds' principal amounts and are callable on specific dates within the period 1997 to 2005.

As described in note 11, Ontario Hydro has used various derivative financial instruments to hedge the foreign exchange exposure related to long-term debt denominated in foreign currencies and to manage the interest rate risk associated with its outstanding long-term debt.

10. Bank Indebtedness

Bank indebtedness includes short-term bank lines of credit which are available to Ontario Hydro in the amount of $600 million (1995 -$600 million), of which $600 million was utilized at year end (1995 - $599 million). The lines of credit are unsecured and bear interest at less than the prime rate. Two United States dollar-denominated revolving lines of credit, one a 364-day credit facility and the other a five-year credit facility, are also available to Ontario Hydro. Each of the lines of credit are in the amount of US $1 billion, none of which was utilized at year end (1995 - nil). Both lines of credit are unsecured and bear interest at the London Interbank Offered Rate (LIBOR) plus 22.5 basis points when fully drawn.

11. Derivative Financial Instruments

Ontario Hydro has used a variety of derivative financial instruments to manage foreign exchange and interest rate risk.

Foreign exchange risk management instruments (millions of stated currency)
The following table summarizes outstanding positions in foreign exchange derivative financial instruments:

	1996			1995
	Notional Principal Outstanding			Notional Principal Outstanding
	Maturing in 1997	Maturing beyond 1997	Total	Total
Forward exchange contracts				
Purchased forward	**US $126**	**US $157**	**US $283**	US $255
	SF 13	–	**SF 13**	SF 15
Sold forward	**US $194**	**US $55**	**US $249**	US $181
Cross currency swap contracts				
Ontario Hydro receives:				
United States dollar	–	**US $104**	**US $104**	US $104
Swiss franc	–	**SF 150**	**SF 150**	SF 150
Japanese yen	–	**¥5,000**	**¥5,000**	¥5,000
New Zealand dollar	–	**NZ $100**	**NZ $100**	–
Australian dollar[1]	–	**AU $568**	**AU $568**	–
Canadian dollar	–	**CDN $423**	**CDN $423**	–
Foreign currency option combination contracts	**US $240**	–	**US $240**	–

1 Periodic swap payments denominated in Japanese yen.

Forward exchange contracts. Ontario Hydro has entered into forward exchange contracts to manage the foreign exchange risk associated with its long-term debt. Forward exchange contracts have also been entered into to hedge firm commitments for future purchases and sales denominated in a foreign currency.

Cross currency swap contracts. Ontario Hydro has entered into cross currency swap contracts to effectively convert principal and interest payments on selected debt issues into Canadian or United States dollars.

Foreign currency option combination contracts. Ontario Hydro has entered into foreign currency option combination contracts (range forwards) to hedge against the impact of a potential decline in the value of the Canadian dollar.

The following table summarizes the currencies in which Ontario Hydro's long-term debt, bank indebtedness and short-term notes are payable, before and after giving effect to Ontario Hydro's foreign exchange risk management activities related to debt:

11. Derivative Financial Instruments *(continued)*

(millions of dollars)	1996		1995	
	Principal Outstanding		Principal Outstanding	
	Before Hedging	After Hedging	Before Hedging	After Hedging
Canadian dollars	27,015	27,170	28,341	29,009
United States dollars	3,891	4,635	4,383	3,959
Australian dollars[1]	590	–	–	–
Swiss francs	153	–	178	–
New Zealand dollars	97	–	–	–
Japanese yen	59	–	66	–
	31,805	31,805	32,968	32,968

1 Coupon payments denominated in Japanese yen.

Interest rate risk management instruments (millions of stated currency)
The following table summarizes outstanding positions in interest rate derivative financial instruments.

	1996			1995
	Notional Principal Outstanding			Notional Principal Outstanding
	Maturing in 1997	Maturing beyond 1997	Total	Total
Swaption contracts sold				
Ontario Hydro potentially pays fixed	CDN$157	CDN$692	CDN$849	CDN$1,936
	US $269	US $193	US $462	US$777
Interest rate swap contracts				
Ontario Hydro receives fixed	–	CDN$3,683	CDN$3,683	CDN$3,245
	US $37	US $744	US $781	US$500
Ontario Hydro pays fixed	CDN$1,498	CDN$3,170	CDN$4,668	CDN$2,443
	US $54	US $653	US $707	US$803

11. Derivative Financial Instruments *(continued)*

Swaption contracts. In 1993 Ontario Hydro converted future potential interest savings related to call options embedded in certain of its bonds to cash, by selling offsetting swaption contracts. These contracts permit holders to require Ontario Hydro to enter into interest rate swaps commencing on the call date. If exercised, the swaptions result in Ontario Hydro making payments based on a fixed interest rate equal to the related bonds' coupon rates, and receiving floating rate payments. United States dollar-denominated swaptions may be cash settled on their exercise dates. Premiums received from the sale of these contracts are being amortized to income, as a reduction of interest expense, over the remaining terms of the related bond issues.

Interest rate swap contracts. As at December 31, 1996, the outstanding receive-fixed interest rate swap contracts have effectively converted fixed interest rates on long-term debt to floating interest rates. These contracts have maturity dates over the period 1998 to 2026 (1995: 1997 to 2005). The outstanding pay-fixed interest rate swap contracts have effectively converted floating interest rates on outstanding debt into fixed interest rates. The majority of the Canadian dollar pay-fixed interest rate swaps mature over the period 1997 to 2004 (1995: 1996 to 2004), while the United States dollar pay-fixed interest rate swaps mature over the period 1997 to 2026 (1995: 1997 to 2005).

The following table summarizes the total amount of long-term debt, bank indebtedness and short-term notes maturing or subject to interest rate resetting within one year and after one year, before and after giving effect to Ontario Hydro's interest rate risk management activities:

	1996				1995			
	Before interest rate risk management activities	**Weighted average interest rate (per cent)**	**After interest rate risk management activities**	**Weighted average interest rate (per cent)**	Before interest rate risk management activities	Weighted average interest rate (per cent)	After interest rate risk management activities	Weighted average interest rate (per cent)
Matures or reprices								
– within one year	**3,217**	**6.4**	**4,571**	**5.9**	4,242	8.5	4,781	8.5
– after one year	**28,588**	**9.5**	**27,234**	**9.4**	28,726	9.8	28,187	9.7
	31,805	**9.2**	**31,805**	**8.9**	32,968	9.6	32,968	9.5

The 1996 amounts in the above table will be affected by treasury activities and the borrowing program in 1997.

12. Fair Value of Financial Instruments and Credit Risk (millions of dollars)

Fair value

The following table presents the carrying amounts and fair values of Ontario Hydro's financial instruments:

	1996		1995	
	Carrying Value	Fair Value[1]	Carrying Value	Fair Value[1]
Financial assets				
Forward exchange contracts	19	12	27	21
Foreign currency option combination contracts	1	1	–	–
Cross currency swap contracts	19	20	42	51
Interest rate swap contracts	4	213	–	95
Financial liabilities				
Long-term debt	30,070	36,500	31,430	37,300
Swaption contracts	308	516	657	979
Forward exchange contracts	1	2	–	4
Foreign currency option combination contracts	1	1	–	–
Cross currency swap contracts	38	18	–	–
Interest rate swap contracts	72	387	33	185

1 Year-end quoted market prices for specific or similar instruments are used to estimate the fair value of each class of financial instrument for which it is practical to estimate that value. For over-the-counter derivative financial instruments, the fair value is determined using pricing models that take into account the current value of the underlying instruments, the time value of money, and mid-market yield curve and volatility factors. The carrying values of cash, short-term investments, accounts receivable, bank indebtedness, short-term notes payable and accounts payable approximate fair value because of the short maturity of those instruments.

Credit risk

Financial assets expose Ontario Hydro to credit risk and concentration of credit risk. As at December 31, 1996, there were no significant concentrations of credit risk with respect to any class of financial assets. Derivative financial instruments expose Ontario Hydro to credit risk, since there is a risk of counter-party default. This risk is limited to the cost of replacing contracts in which Ontario Hydro has an unrealized gain.

Credit risk is monitored and minimized by dealing only with a diverse group of highly rated counter parties. In addition, as a means of further reducing its credit exposure on derivative financial instruments, Ontario Hydro enters into master netting agreements with its counter parties to enable it to settle derivative financial assets and liabilities with the counter party on a net basis in the event that the counter party defaults. The existence of these master netting agreements had the effect of reducing Ontario Hydro's current credit risk exposure on derivative financial assets from $246 million to $107 million as at December 31, 1996.

13. Accrued Fixed Asset Removal and Used Nuclear Fuel Disposal Costs

(millions of dollars)	1996	1995
Accrued fixed asset removal costs		
– accrued decommissioning costs	**907**	764
– accrued fuel channel removal costs	**558**	610
	1,465	1,374
Accrued used nuclear fuel disposal costs	**1,136**	1,045
	2,601	2,419

Accrued fixed asset removal costs

Accrued fixed asset removal costs are the costs of decommissioning nuclear and fossil generating stations and heavy water production facilities after the end of their service lives, and the costs of removing certain fuel channels which are expected to be replaced during the life of the nuclear reactors. The significant assumptions used in estimating future fixed asset removal costs were:

- decommissioning of nuclear generating stations in the 2042 to 2062 period on a deferred dismantlement basis (dismantlement following storage with surveillance for a 30-year period after shutdown of the reactors), and an average transportation distance of 1,000 kilometres from nuclear generating facilities to disposal facilities (1995 - 1000 kilometres);
- interest rates through to 2065 ranging from 7% to 10% (1995 - 6% to 10%);
- escalation rates through to 2065 ranging from 1% to 7% (1995 - 1% to 7%); and
- removal and replacement of fuel channels in nuclear generating stations during the following periods :

	1996	1995
Bruce "A" Units 3 & 4	**2006 to 2008**	2000 to 2008
Pickering "B"	**2009 to 2014**	2009 to 2016
Bruce "B"	**2011 to 2017**	2011 to 2019
Darlington	**2016 to 2022**	2016 to 2024

The significant assumptions underlying the estimates of accrued fixed asset removal costs are subject to periodic review. These assumptions, as well as the existing methods and technology used for decommissioning and fuel channel removal and replacement, may change and could result in changes to these costs.

Accrued used nuclear fuel disposal costs

The significant assumptions used in estimating the future used nuclear fuel disposal costs were:

- an in-service date of the year 2025 (1995 - 2025) for used nuclear fuel disposal facilities;
- an average transportation distance of 1,000 kilometres (1995 -1,000 kilometres) from nuclear generating facilities to disposal facilities;
- interest rates through to the disposal date ranging from 7% to 9% (1995 - 6% to 9%); and
- escalation rates through to the disposal date ranging from 1% to 7% (1995 - 1% to 7%).

The significant assumptions underlying the estimates of accrued used nuclear fuel disposal costs are subject to periodic review. These assumptions, as well as the existing methods and technology used for used fuel disposal, may change and could result in changes to these costs.

14. Contingencies and Commitments

Manitoba Hydro

In December 1992, due to a projected surplus in generating capacity, Ontario Hydro exercised its right to terminate its long-term power purchase contract with Manitoba Hydro. In Manitoba Hydro's certificate of costs for reimbursement, an amount of $55 million was claimed for costs incurred by Manitoba Hydro prior to entering into the contract with Ontario Hydro on December 7, 1989. Ontario Hydro is of the opinion that costs incurred by Manitoba Hydro before December 7, 1989 are not reimbursable by Ontario Hydro under the contract. As well, based on a review of the certificate of costs, it appears that the total cost claimed by Manitoba Hydro may have been overstated. Ontario Hydro has commenced an action against Manitoba Hydro for a declaration that Ontario Hydro is not obliged to pay costs incurred prior to entering into the contract and for a further judgment against Manitoba Hydro requiring the repayment of amounts which were improperly claimed by Manitoba Hydro and paid by Ontario Hydro under the contract. In July 1994, Manitoba Hydro issued its statement of defence and counterclaim to Ontario Hydro. Manitoba Hydro claims that they are entitled to an immediate payment from Ontario Hydro of $57 million, representing the claim for costs incurred by Manitoba Hydro prior to entering into the contract, plus interest. At this time, the outcome of these claims are not determinable, and as such, no provision has been accrued in Ontario Hydro's financial statements with respect to any amounts in dispute.

Power purchase agreements

Ontario Hydro purchases a portion of its electricity requirements pursuant to long-term contractual power purchase agreements (PPAs) with various independent power producers. The PPAs, representing in-service capacity of approximately 1,225 megawatts as at December 31, 1996 (1995 - 1,050 megawatts), expire on various dates from 1999 to 2045. The obligations to purchase power under these contracts over the next 20 years have a total net present value of approximately $6,550 million with estimated payments over the next five years, in dollars of the year, as follows: 1997 - $685 million; 1998 - $706 million; 1999 - $726 million; 2000 - $741 million; and 2001 - $756 million.

Deliveries in the aggregate accounted for approximately 5.5% of Ontario Hydro's 1996 electric energy requirements (1995 - 5.2%). The amount of energy received and the total payments made under these agreements were:

	1996	1995
Gigawatt-hours received	**7,927**	7,565
Power purchases (millions of dollars)	**482**	428

Loan guarantees

Ontario Hydro is contingently liable under guarantees given to third-party lenders who have provided long-term financing to certain independent power producers. These guarantees total approximately $182 million as at December 31, 1996 (December 31, 1995 -$193 million).

15. Retained Earnings (millions of dollars)

	1996	1995
Balance at beginning of year	**4,540**	3,912
Net (loss) income	**(1,988)**	628
Balance at end of year	**2,552**	4,540

The balance in this account is retained for purposes prescribed under the Power Corporation Act. On January 1, 1997, the retained earnings balance of $2,552 million will be reduced by $763 million to $1,789 million as a result of charging the transition obligation associated with the change in accounting for other post-employment benefits (see note 17).

16. Consolidated Statement of Changes in Cash Position

The changes in non-cash working capital and long-term accounts payable affecting operations consisted of the following:

(millions of dollars)	**1996**	1995
Accounts receivable - decrease	**62**	138
Fuel for electric generation, materials and supplies - (increase) decrease	**(20)**	143
Accounts payable and accrued charges - (decrease)	**(10)**	(248)
Accrued interest -(decrease)	**(104)**	(12)
Long-term accounts payable and accrued charges - (decrease)	**(14)**	(1)
	(86)	20

17. Benefit Plans

Ontario Hydro's employee benefit programs include the pension plan, the group life insurance plan, the long-term disability plan and the group health care plan.

Pension plan
Pension costs for 1996 were $111 million (1995 - $74 million). In 1996, $89 million (1995 - $59 million) of the pension costs were charged to operations and $22 million (1995 - $15 million) were capitalized as part of the cost of fixed assets.

The actuarial present value of the accrued pension benefits is estimated to be $5,987 million as at December 31, 1996 (1995 - $6,290 million), and the pension plan assets available for these benefits were $8,964 million (1995 - $7,790 million) based on current fair values.

The actuarial present value of the accrued pension benefits was determined for accounting purposes using the following significant assumptions which reflect management's best estimate and take into consideration the long-term nature of the pension plan:

- rate used to discount future pension benefits 8.25% (1995 - 7.75%);
- salary escalation rate 3.00% (1995-3.00%) plus an age and service dependent increase in respect of promotion, progression and merit
- average long-term rate used to estimate improvements in pension benefits to partially offset the effect of increase in cost of living 2.06% (1995 - 2.06%); and
- average remaining service period of employees - 15 years (1995 - 16 years).

Deferred pension costs on the statement of financial position represent cumulative difference between funding contributions, including special payments, and pension costs. As at December 31, 1996, deferred pension costs amounted to $131 million (1995 -$149 million) and primarily reflect special payments made in 1990 and 1991 relating to past service benefit improvements offset by costs associated with the 1993 voluntary staff reduction program. The costs of pension benefit improvements funded by the special payments are being amortized as a charge to pension costs on a straight-line basis over the average remaining service period of employees.

Group life insurance plan
Ontario Hydro paid $1 million (1995 -$6 million) in premiums for basic insurance coverage for employees. Premiums for additional coverage, if requested, are paid for by the employee.

Group health care plan
Ontario Hydro provides a group health care plan to its employees. In 1996, the cost of providing these benefits was $62 million (1995 - $55 million).

Other post-employment benefits
In addition to pension benefits, Ontario Hydro provides group life insurance and health care benefits to its retired employees and, in certain cases, their surviving spouses and unmarried dependents. The cost of providing the group life insurance and health care benefits is charged to operations as the benefits are paid. In 1996, the cost of providing these benefits was $22 million (1995 -$21 million).

As well, Ontario Hydro provides long-term disability benefits to qualifying employees during extended absences from work due to sickness or injury. The long-term disability plan is entirely funded by Ontario Hydro. For 1996, contributions to the plan amounted to $12 million (1995 -$10 million).

17. Benefit Plans *(continued)*

In December 1996, Ontario Hydro decided to adopt accrual accounting for other post-employment benefits in anticipation of new recommendations from the Canadian Institute of Chartered Accountants on the accounting for other post-employment benefits. Effective January 1, 1997, the costs of other post-employment benefits will be actuarially determined for accounting purposes based on assumptions that reflect management's best estimates of the effect of future events on the actuarial present value of the accrued benefits. The transition obligation of $763 million which arises on conversion to accrual accounting will be charged to retained earnings on January 1, 1997.

18. Research and Development

In 1996, approximately $91 million of research and development expenditures were charged to operations, $4 million were capitalized and $30 million were charged to accrued provisions (1995 -$73 million; $9 million and $35 million, respectively).

19. Stranded Debt, Industry Changes and Asset Impairment

Given recent and expected changes in the nature of the Ontario electricity industry, Hydro has recognized that its existing debt load is too great and that it is over-leveraged to compete in a future restructured market. In a future competitive marketplace, certain of Hydro's assets may no longer be recoverable from revenues. This situation has resulted from a combination of recent load growth being less than predicted and the effects of external industry restructuring.

Moreover, Ontario Hydro has operated a a rate-regulated, non-tax-paying monopoly since the Corporation was formed over 90 years ago with a mandate to supply power at cost upon demand. Accordingly, Hydro has developed the asset base necessary to meet the predicted needs of Ontario's electricity customers. In common with many government-owned public utilities, the development of this asset base has resulted in a highly leveraged financial structure for the Corporation.

Consistent with changes occurring in other North American jurisdictions, it is anticipated that Hydro's regulated and monopoly status will change during the next several years to allow for more competition and reduced regulation in certain parts of its operations, in particular, in power generation. These external changes are expected to result in significant additional financial and organizational restructuring of Hydro and the introduction of some form of corporate taxation.

The Advisory Committee on Competition in Ontario's Electricity System (the Macdonald Committee) was asked to make recommendations on options for introducing competition within Ontario's electricity industry. The Macdonald Committee estimated that a $15-billion reduction in Hydro's existing debt would be required to restructure Hydro along more commercial lines and to offset unrecoverable assets. Ontario Hydro has carried out further analysis and has estimated that a debt level that is between $10 billion and $21 billion less than the current level would result in a more appropriate financial structure for the Corporation when competition is introduced into Ontario. Hydro has adopted a $16-billion estimate of potentially stranded debt for strategic discussion purposes.

A number of mechanisms exist to address stranded debt, such as a debt to equity conversion, an exit fee imposed on departing customers, a transition charge collected as a component of transmission tariffs, or a transition charge collected as a surcharge on distribution tariffs, some of which are used or have been proposed in other North American jurisdictions. Hydro expects that a suitable mechanism can be put in place to allow any stranded debt to be discharged over a reasonable time frame without the need for rate increases.

Of Hydro's $16-billion stranded debt estimate, about $2 billion can be related to assets that may not be recoverable in a future competitive environment and to uneconomic power purchase agreements with independent power producers. Specifically, Hydro has estimated the potential loss on these power purchase agreements to be within the range of nil to $2.1 billion. Given the significant amount of uncertainty regarding future electricity prices, the existence and amount of any potential future loss is not reasonably determinable.

The possibility that certain assets and power purchase agreement costs may in future no longer be fully recoverable does not pose a risk for holders of Ontario Hydro's bonds and notes, which are either held, or guaranteed as to principal and interest, by the Province of Ontario.

20. Comparative Figures

Certain of the 1995 comparative figures in the financial statements have been reclassified to conform with the 1996 financial statement presentation.

Five-Year Summary of Financial and Operating Statistics

(millions of dollars)	1996	1995	1994	1993	1992
Revenues					
Primary power and energy					
Municipal utilities	**5,857**	5,899	5,829	5,721	5,281
Retail customers	**1,647**	1,635	1,688	1,641	1,568
Direct industrial customers	**903**	914	866	873	863
	8,407	8,448	8,383	8,235	7,712
Secondary power and energy	**172**	233	349	128	56
Other revenues	**307**	315	264	112	104
	8,886	8,996	8,996	8,475	7,872
Costs					
Operation, maintenance and administration[1]	**2,008**	1,916	1,913	2,131	2,296
Fuel used for electric generation[1]	**615**	607	608	952	1,191
Power purchased	**571**	495	341	260	186
Provincial government levies	**282**	283	284	286	270
Depreciation and amortization	**1,656**	1,640	1,595	1,506	1,198
	5,132	4,941	4,741	5,135	5,141
Income before financing charges	**3,754**	4,055	4,255	3,340	2,731
Financing charges					
Gross interest	**3,206**	3,574	3,544	3,849	3,782
Capitalized interest	**(54)**	(78)	(123)	(462)	(1,231)
Investment income	**(52)**	(123)	(63)	(65)	(119)
Foreign exchange	**82**	54	42	8	(13)
	3,182	3,427	3,400	3,330	2,419
Income before corporate write-offs	**572**	628	855	10	312
Corporate write-offs	**2,560**	–	268	3,614	–
Net (loss) income	**(1,988)**	628	587	(3,604)	312

(millions of dollars)	**1996**	1995	1994	1993	1992
Financial position					
Total assets	**39,870**	42,984	44,100	44,706	46,671
Fixed assets	**36,818**	39,299	39,907	40,740	40,690
Long-term debt[2]	**30,070**	31,430	32,967	33,685	34,034
Equity	**2,552**	4,540	3,912	3,325	6,931
Cash flows					
Cash provided from operating activities	**2,228**	2,479	2,256	1,332	1,691
Cash (used for) provided from financing activities	**(1,533)**	(1,686)	(1,245)	404	1,784
Cash used for investment in fixed assets	**868**	932	1,089	1,871	3,375
Investment in fixed assets	**844**	881	1,164	2,296	3,527
Financial indicators					
Interest coverage before corporate write-offs[3]	**1.19**	1.19	1.25	1.00	1.09
Interest coverage after corporate write-offs[3]	**0.35**	-	1.17	0.04	-
Debt ratio[4]	**0.930**	0.886	0.904	0.918	0.841
Energy sales[5] millions of kilowatt-hours					
Primary energy sales					
Municipal utilities	**94,565**	94,606	93,405	92,093	91,317
Retail customers	**18,603**	18,390	18,499	18,519	18,938
Direct industrial customers	**18,490**	18,651	17,552	17,415	18,094
	131,658	131,647	129,456	128,027	128,349
Secondary energy sales[5]	**6,112**	9,203	12,628	4,807	1,896
	137,770	140,850	142,084	132,834	130,245

	1996	1995	1994	1993	1992
Energy and demand					
In-service capacity megawatts[6]	**29,844**	29,244	30,135	31,851	31,309
December primary peak demand megawatts	**20,895**	22,613	21,849	20,506	21,339
Primary energy made available millions of kilowatt-hours[7]	**137,418**	137,038	134,874	133,769	134,376
Number of primary customers[5]					
Municipal utilities	**306**	306	306	309	311
Retail customers	**963,043**	962,426	954,502	942,812	940,617
Direct industrial customers	**103**	103	103	104	107
Average revenue[5] in cents per kilowatt-hour of total energy sales					
Primary power and energy					
Municipal utilities	**6.194**	6.235	6.241	6.212	5.783
Retail customers	**9.431**	9.376	9.684	9.265	8.884
Direct industrial customers	**4.884**	4.901	4.934	5.013	4.770
All primary customers combined	**6.441**	6.464	6.529	6.473	6.070
Secondary power and energy	**2.814**	2.532	2.764	2.663	2.954
All classifications combined	**6.279**	6.205	6.192	6.334	6.024
Average rate increases (decreases) expressed as a per cent					
Municipal utilities	**0.0**	0.0	0.0	8.2	11.8
Retail customers	**(0.6)**	0.0	0.0	6.5	11.8
Direct industrial customers	**(0.2)**	(0.7)	0.0	8.2	11.8
All primary customers combined	**(0.1)**	(0.1)	0.0	7.9	11.8

	1996	1995	1994	1993	1992
Average cost[1,5,8] in cents per kilowatt-hour of energy generated					
Hydroelectric					
Operation, maintenance and administration	**.312**	.316	.318	.277	.280
Water rentals	**.335**	.344	.336	.330	.317
Depreciation, debt guarantee fee and financing charges	**.313**	.415	.543	.488	.454
Other revenues	**(.006)**	(.003)	(.011)	–	–
	0.954	1.072	1.186	1.095	1.051
Nuclear					
Operation, maintenance and administration	**1.228**	1.066	1.032	.973	1.152
Uranium	**.255**	.268	.285	.541	.554
Depreciation, debt guarantee fee and financing charges	**4.143**	3.946	3.530	3.910	3.080
Other revenues	**(.118)**	(.103)	(.118)	(.009)	(.008)
	5.508	5.177	4.729	5.415	4.778
Fossil					
Operation, maintenance and administration	**1.051**	1.166	1.331	1.311	.989
Coal, gas and oil	**2.218**	2.394	2.378	2.515	2.426
Depreciation, debt guarantee fee and financing charges	**2.496**	3.229	3.732	3.022	1.648
Other revenues	**(.073)**	(.121)	(.020)	(.007)	(.029)
	5.692	6.668	7.421	6.841	5.034
Average number of employees					
Regular	**21,313**	21,505	22,525	26,442	28,835
Non-regular[9]	**1,873**	1,573	2,082	3,331	6,004

1 Operation, maintenance and administration and fuel costs have been restated to exclude other revenues.
2 Long-term debt includes long-term debt payable within one year.
3 Interest coverage represents net income plus interest on bonds, notes, and other debt divided by interest on bonds, notes and other debt.
4 Debt ratio represents debt (bonds and notes payable, short-term notes payable, other long-term debt, unamortized swaption premiums, accrued fixed asset removal and used nuclear fuel disposal costs and bank lines of credit less unamortized foreign exchange gains and losses) divided by debt plus equity.
5 Figures for 1996 are preliminary.
6 In-service capacity represents the net output power supplied by all generating units, net firm power purchase contracts and purchases from independent power producers. Excluded are non-operating reserve facilities of: 1996 - 4,300 MW; 1995 - 5,043 MW; 1994 - 4,297 MW; 1993 - 2,686 MW; and 1992 - 1,554 MW.
7 Primary energy made available represents primary energy sales plus transmission losses and energy used for heavy water production and generation projects.
8 Average cost per kilowatt-hour represents the costs attributable to generation but excludes the costs related to transmission, distribution and corporate administrative activities. These figures reflect the historical accounting costs of operating facilities and the actual energy generated by these facilities during the year.
9 The majority of non-regular staff are construction trades persons.

Customers Served by Ontario Hydro and Associated Municipal Utilities	1996[1]	1995	1994	1993	1992
Total number of customers in thousands					
Residential	**3,369**	3,329	3,293	3,252	3,205
Farm	**101**	103	103	103	104
Commercial and industrial	**439**	441	437	436	430
	3,909	3,873	3,833	3,791	3,739
Average annual use in kilowatt-hours per customer					
Residential	**10,318**	10,421	10,763	10,965	11,024
Farm	**23,933**	22,432	23,138	23,660	23,496
Commercial and industrial	**204,103**	205,123	201,265	198,841	201,112
Average revenue[2] in cents per kilowatt-hour					
Residential	**8.87**	8.84	8.83	8.77	8.12
Farm	**9.33**	8.96	8.93	8.82	8.19
Commercial and industrial	**6.54**	6.80	6.75	6.76	6.31
All customers	**7.23**	7.27	7.37	7.38	6.86

1 Figures for 1996 are preliminary.
2 Includes rural rate assistance.

UNDERTAKING JTX3.17

Undertaking

TO CLARIFY THE WAGE AND SHARE COMPENSATION CALCULATIONS IN EX. L-6.6-15 SEC-079.

Response

Attachment 1 provides the details requested to clarify the calculations. Attachment 1 contains confidential information.

ATTACHMENT 1 - L-6.6-15 SEC-79 Details
Estimate of Expected Wage Increases Including Value of Hydro One Share Performance Plan

Line #	**PWU CALCULATIONS** (Note 1)	**Actual Mar 31 2015**	**Estimate for Contract Year Beginning Apr 1**						
			2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
1	Number of employees (Total OPG per 2016-2018 BP)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Wage Escalation %		1.0%	1.0%	1.0%	[redacted]	[redacted]	[redacted]	[redacted]
3	Modelled Average Salary per Employee before Share Award (Previous Line 3 x (1 + Line 2))	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	**Modelled Wages** (Line 1 x Line 3) / (1,000,000)			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Estimated No. of Employees Eligible for Shares (starting in 2017)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	% of Base Salary Used to Determine # of Shares (Ex. F4-3-1, p. 17)		2.75%						
7	Hydro One IPO Share Price		$ 20.50						
8	Average No. of Shares Awarded per Employee (starting in 2017) (Line 3 x Line 6) / (Line 7)		[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Cost per Share (Ex. F4-3-1, pp. 17-18)				$ 23.65	$ 23.65	$ 23.65	$ 23.65	$ 23.65
10	Average Share Cost per Employee (starting in 2017) (Line 8 x Line 9)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	**Modelled Share Value Awarded to Employees** (Line 5 x Line 10)				[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	**Sum of Modelled Wages and Share Value** (Line 4 + Line 11)			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	**Total Modelled Wages and Share Value per Employee** (Line 12 / Line 1)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	**Implied Escalation (year over year)** (Current Line 13 - Previous Line 13) / (Previous Line 13)		**1.0%**	**1.0%**	**3.9%**	[redacted]	[redacted]	[redacted]	[redacted]

Note 1: Calculation is based on illustrative, modelled data in order to approximate implied expected year over year increases in wages inclusive of Hydro One share awards. Modelled data may differ from actual compensation cost data reflected elsewhere in OPG's evidence.

Line #	**SOCIETY CALCULATIONS** (Note 1)	**Actual**	**Estimate for Contract Year Begining January 1**

ATTACHMENT 1 - L-6.6-15 SEC-79 Details

Estimate of Expected Wage Increases Including Value of Hydro One Share Performance Plan

Line #	SOCIETY CALCULATIONS (Note 1)	Dec 31 2015	2016	2017	2018	2019	2020	2021
1	Number of employees (Total OPG per 2016-2018 BP)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Wage Escalation %		1.0%	1.0%	1.0%	[redacted]	[redacted]	[redacted]
3	Modelled Average Salary per Employee before Share Award (Previous Line 3 x (1 + Line 2))	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	**Modelled Wages** (Line 1 x Line 3) / (1,000,000)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Estimated No. of Employees Eligible for Shares (starting in 2018)				[redacted]	[redacted]	[redacted]	[redacted]
6	% of Base Salary Used to Determine # of Shares (Ex. F4-3-1, p. 17)		2.00%					
7	Hydro One IPO Share Price		$ 20.50					
8	Average No. of Shares Awarded per Employee (starting in 2018) (Line 3 x Line 6) / (Line 7)		[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
9	Cost per Share (Ex. F4-3-1, pp. 17-18)				$ 23.65	$ 23.65	$ 23.65	$ 23.65
10	Average Share Cost per Employee (starting in 2018) (Line 8 x Line 9)				[redacted]	[redacted]	[redacted]	[redacted]
11	**Modelled Share Value Awarded to Employees** (Line 5 x Line 10)				[redacted]	[redacted]	[redacted]	[redacted]
12	**Sum of Modelled Wages and Share Value** (Line 4 + Line 11)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	**Total Modelled Wages and Share Value per Employee** (Line 12 / Line 1)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	**Implied Escalation (year over year)** (Current Line 13 - Previous Line 13) / (Previous Line 13)		**1.0%**	**1.0%**	**2.7%**	[redacted]	[redacted]	[redacted]

Note 1: Calculation is based on illustrative, modelled data in order to approximate implied expected year over year increases in wages inclusive of Hydro One share awards. Modelled data may differ from actual compensation cost data reflected elsewhere in OPG's evidence.

UNDERTAKING JTX3.18

Undertaking

TO GIVE MORE INFORMATION AS TO WHY OPG PICKED THE COMPARATORS INSTEAD OF AON HEWITT IN EX. L-6.6-1 STAFF-157, ATTACHMENT 2.

Response

AON provides guidance to its clients in selecting appropriate comparators, providing information such as industry sector, size and geography to assist in that decision; however the final selection of peers is the client's decision.

The organizations OPG selected focused primarily on public sector organizations, with some private utilities included. The emphasis on public sector arose following the review conducted by the Auditor General in 2013 which utilized the Ontario Public Service as the primary comparator in their assessment.

UNDERTAKING JTX3.19

Undertaking

To advise whether sick days are included as a benefit or is that excluded from the study at Ex.L-6.6 -1 Staff-157, Attachment 2 .

Response

Sick days are included in the benefits listed under the Disability grouping, in Ex. L-6.6-1 Staff 157, Attachment 2, p.91.

UNDERTAKING JT3.20

Undertaking

TO PROVIDE STAFFING PLANS INCLUDING BOTTOM LINE NUMBERS UNDERLYING THE BUSINESS PLAN FOR THIS APPLICATION.

Response

Attachment 1 presents the staffing plans for the Nuclear 2016 business plan, including bottom line numbers. Attachment 1 is being filed confidentially in its entirety in accordance with the OEB's practice direction on confidential filings.

JT3.20 ATTACHMENT 1

IS CONFIDENTIAL IN ITS ENTIRETY

UNDERTAKING JT3.21

Undertaking

TO REQUEST CONCENTRIC'S COMMENT ON MR. JANIGAN'S QUESTION ABOUT THE CRVA AND THE INCREASE IN EQUITY THICKNESS

Response

This response was prepared by Concentric Energy Advisors.

Yes, Concentric's opinion is that an appropriate equity ratio for OPG is no less than 49%, assuming continuation of all applicable existing Deferral and Variance accounts for both OPG's prescribed hydroelectric and nuclear facilities during the 2017-2021 period, including the Capacity Refurbishment Variance Account ("CRVA"). The CRVA was put in place in EB-2007-0905, and was in effect when OPG's rates were set in EB-2010-0008 and EB-2013-0321. As discussed in Exhibit C1-1-1, Attachment 1 (i.e., Concentric's report on the Common Equity Ratio for OPG's Regulated Generation), Concentric's recommendations were based on a risk analysis of OPG's overall regulated operations, including, but not limited to, the Darlington Refurbishment Project. Concentric's analysis focused on changes to OPG's risk profile since EB-2013-0321, including the increase in nuclear rate base relative to hydroelectric rate base, and also considered the equity ratios of a proxy group of regulated utilities. Concentric did not consider the existence of the CRVA to be reflective of a change in risk for OPG, nor does Concentric consider the CRVA to decrease the risk of nuclear generation relative to hydroelectric generation. In regards to the Darlington Refurbishment Project ("DRP") specifically, it is a mega project that will more than double OPG's rate base and that involves multiple complex work packages, numerous third-party vendors, and the coordination of multiple scopes of work, all within the highly regulated and safety-conscious environment of a nuclear facility. The CRVA allows the recovery of the return on and of the difference between forecast and actual costs until the project is moved into rate base. This mitigates the potential lag between (a) changes in projected costs and actuals, and (b) the recovery of those costs differentials. All costs, however, remain subject to prudence review, which is not a risk that is mitigated by the CRVA.

UNDERTAKING JT3.22

Undertaking

WITH REFERENCE TO CCC INTERROGATORY #8, TO PROVIDE A LIST OF THE PIRS COMPLETED AND APPROVED FOR THE NUCLEAR BUSINESS WITHIN THE LAST 12 MONTHS, INCLUDING THE DATE OF THE PIR, THE BUDGET, AND THE ACTUAL COST OF THE PROJECT

Response

Project Title	PIR Approval Date	Budget ($M)	Actual Cost ($M)
Radiation Sheilding Structure	26-Nov-15	4.0	4.0
PN Clean Water Supply for EHPSW and ELPSW Lube Lines	26-Nov-15	0.6	0.1
PA Dryer Beetle Power Supply Modification	27-Nov-15	0.4	0.2
Standby Generator Governor Upgrades	5-Jan-16	22.9	22.8
TMB Fire Code Compliance	18-Jan-16	0.4	0.3
PN Post Accident Gamma Monitoring	23-Jan-16	3.8	2.8
Radioactive Emission Reduction (Stack Monitors)	28-Jan-16	13.4	10.6
Modified 37-Element Bundles	4-Jul-16	9.0	6.0
PA Unit 4 FM Service Room Grating Modification	23-Jul-16	0.4	0.3
Pickering 'A' Machine Shop Modification	28-Jul-16	1.6	1.6
PA Turbine Steam Release Valve Solenoid Reliability Improvement	25-Aug-16	0.9	0.6
Severe Accident Management Guidance (SAMG) Implementation	22-Sep-16	19.5	15.4
Power Operated Valve Program Recovery Project	30-Sep-16	6.9	6.8
PA RB Ventilation Dampers Alternative Containment Boundary Configuration	3-Oct-16	0.3	0.1
PA EQ Containment Damper Deficiency - Installation of New Maintenance Dampers	18-Oct-16	1.5	1.4

UNDERTAKING JT3.23

Undertaking

TO CONFIRM WHETHER LEI STUDIED THE IMPACT OF CYCLICAL MACRO-ECONOMIC VARIABLES ON PRODUCTIVITY GROWTH IN THE HYDROELECTRIC GENERATION INDUSTRY AND, IF SO, TO PROVIDE ANY RELEVANT RESEARCH

Response

LEI did not analyse "cyclical macro-economic variables" in its TFP growth study for the hydroelectric generation industry.

LEI's study measured the TFP growth of a specific industry. This is an important consideration when comparing and contrasting LEI's study to other potential TFP studies, like Statistics Canada's business sector studies of MFP. While a study of total factor productivity in the economy at large may be affected by business cycles, this is not likely the case for an industry-specific study, such as the one performed by LEI for hydroelectric generation.

UNDERTAKING JT3.24

Undertaking

PART 1: TO ADVISE IF LEI CAN PROVIDE THE INFORMATION REQUESTED; NAMELY, FOR EACH UTILITY IN THE SAMPLE OF LEI'S STUDY FOR EACH YEAR, ADVISE WHAT IS THE ANNUAL PRODUCTIVITY GROWTH RATE THAT LEI HAS CALCULATED FOR THAT UTILITY IN THAT YEAR AND, IF POSSIBLE, TO SEPARATE THE CANADIAN UTILITIES FROM THE AMERICAN UTILITIES; ALSO, IF POSSIBLE, TO HIGHLIGHT WHICH DATA ARE SPECIFIC TO OPG

AND

PART 2: TO ADVISE IF LEI CAN PROVIDE THE STANDARD DEVIATION OF ANNUAL PRODUCTIVITY GROWTH RATES OF UTILITIES IN THEIR SAMPLE, ON A BEST EFFORTS BASIS

AND

PART 3: TO ADVISE IF LEI CAN CONFIRM EP'S CALCULATION THAT THE STANDARD DEVIATION OF ANNUAL PRODUCTIVITY GROWTH RATES AROUND THE MEAN OF NEGATIVE 1.01 IS IN THE RANGE OF 8.05 PERCENTAGE POINTS TO 8.4 PERCENTAGE POINTS, ON A BEST EFFORTS BASIS

Response

The following response was provided by LEI.

PART 1

Please find below the annual productivity growth rate that LEI has calculated for each utility in the sample of LEI's industry TFP study. OPG is the only Canadian peer.

Chart 1 - TFP index Growth - Average growth method (%)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	AVG
OPG	-3.2	5.9	-5.3	1.1	-4.2	11.1	-1.7	-16.7	6.6	-6.6	6.1	0.8	**-0.49**
AB Power	33.6	-27.0	0.4	-37.4	-82.8	50.2	97.0	-51.4	-12.0	-19.2	72.5	-40.9	**-1.41**
AP Power	50.7	-17.7	-15.2	-7.0	-5.2	-12.1	19.6	-6.4	-3.3	6.2	13.8	-33.3	**-0.82**
Ameren MI - Union	-8.8	30.4	2.7	-76.7	46.8	6.2	2.6	8.0	-6.1	-26.6	21.0	-23.7	**-2.02**
Avista	-14.8	6.5	-5.9	12.4	-11.3	3.9	-3.2	-6.9	24.3	-9.6	-14.2	15.1	**-0.30**
Duke	21.5	-26.7	8.8	-12.8	-6.6	4.7	-1.3	-2.9	-10.8	-6.3	26.5	-3.1	**-0.76**
GA Power	50.7	-35.7	8.0	-35.0	-18.2	-36.5	110.3	-22.2	-13.4	5.8	65.1	-38.1	**3.41**
ID Power	1.7	-2.9	2.8	39.4	-40.4	11.0	16.3	-10.0	40.6	-32.6	-34.5	9.4	**0.06**
PacifiCorp	5.5	-16.1	-3.5	36.5	-21.7	0.0	-7.0	8.3	21.4	-4.7	-32.8	20.4	**0.53**
PG&E	10.3	-7.4	14.5	17.8	-61.0	-0.3	9.6	16.1	13.3	-50.1	-2.3	-25.8	**-5.44**
Portland	-1.3	3.3	-9.4	23.2	-14.9	0.1	-1.1	6.2	7.7	-9.8	-14.9	-4.9	**-1.32**
SCE&G	28.9	-12.2	12.2	-26.5	8.0	-13.9	-3.7	0.8	-13.4	6.7	2.5	-28.4	**-3.26**
Seattle	-12.9	-1.1	-7.5	19.1	-4.2	-4.2	-6.9	-2.9	28.3	-9.7	-16.8	17.1	**-0.15**
SEPA	50.2	-10.8	12.2	-58.7	-0.9	-17.2	28.4	14.8	-13.9	-11.4	34.6	-5.7	**1.80**
SoCal Edison	14.2	-13.2	37.2	-2.5	-70.1	2.1	33.5	11.3	9.6	-48.7	-20.8	-24.3	**-5.98**
VA Electric	6.6	-14.3	-20.6	9.5	15.0	-40.5	30.3	19.8	-12.5	48.1	-38.9	-1.7	**0.06**

PART 2

Please find below the sample standard deviation of the annual productivity growth rate of each utility in the sample of LEI's industry TFP study.[1] Note the calculation of standard deviation is based on 12 data points for year over year changes in the TFP index, from 2002 to 2014. LEI used the following formula to calculate the sample standard deviation:

$$s = \sqrt{\sum (x-\mu)^{-2} / n - 1}$$

where: x = each value in the data set; μ = mean value of the data set; Σ = summation (or total); n = number data points

Standard deviation of annual productivity growth rates of utilities, 2002-2014, in LEI's sample (%)

Year	STDEV
OPG	7.5
AB Power	54.0
AP Power	21.5
Ameren MI - Union	31.5
Avista	12.7
Duke	14.6
GA Power	47.9
ID Power	26.4
PacifiCorp	19.5
PG&E	26.6
Portland	10.8
SCE&G	16.6
Seattle	14.0
SEPA	28.7
SoCal Edison	31.6
VA Electric	26.8

[1] As discussed in Section 6.3 of LEI's report, the index method for calculating TFP trends is not a parametric statistical technique. Furthermore, utilizing statistical techniques such as standard deviation with an inadequate sample size can influence quality and accuracy of conclusions. The 12 data points used in the above calculation for standard deviation may not meet the prerequisites for sample size for purposes of hypothesis testing. Furthermore, as also discussed in Section 6.3 of LEI's report, in a multi-firm analysis of this nature, numerical differences when comparing individual peer TFP growth rates should generally not be given too much significance.

PART 3

The standard deviation between annual industry TFP growth rates from 2002 to 2014 (12 data points) using the sample formula was 8.40% and using the population formula was 8.05%.[2] Note, utilizing statistical techniques such as standard deviation with an inadequate sample size can influence quality and accuracy of conclusions.

Year	Peer Industry
2002-2003	7.11%
2003-2004	-4.35%
2004-2005	1.58%
2005-2006	1.17%
2006-2007	-16.98%
2007-2008	3.40%
2008-2009	9.61%
2009-2010	-5.85%
2010-2011	7.97%
2011-2012	-14.42%
2012-2013	2.22%
2013-2014	-3.60%
AVERAGE TFP	**-1.01%**
STDEV sample	**8.40%**
STDEV population	**8.05%**

Sample Standard Deviation formula: $s = \sqrt{\sum(x-\mu)^2/n-1}$
Population Standard Deviation formula: $\sigma = \sqrt{\sum(x-\mu)^2/n}$

where:
x = each value in the data set
μ = mean value of the data set
Σ = summation (or total)
n = number data points

[2] Although LEI reported the result of the application of the population formula, it should not be used in this case since the 12 data points are only a sample of the underlying population.