ONTARIO POWER GENERATION

News
from Ontario Power Generation

700 University Avenue Toronto, ON M5G 1X6
Tel: 416-592-4008 or 1-800-592-4008 Fax: 416-592-2178
www.opg.com

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OPG REPORTS 2018 THIRD QUARTER FINANCIAL RESULTS

Darlington Refurbishment Project Remains on Time and on Budget at Two-Year Mark

Toronto: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $279 million for the third quarter of 2018, compared to $131 million for the same quarter in 2017.

"Darlington Refurbishment remains on time and on budget as we mark the second anniversary of the 10-year mega-project. This remarkable achievement is the result of the dedicated team of professionals who are delivering Canada's largest clean energy project, while generating billions in economic benefits for Ontarians, through the creation of thousands of jobs," said Jeff Lyash, OPG President and CEO. "We are also pleased that for the ninth consecutive year, Darlington Nuclear has achieved the highest possible safety rating from our regulator, the Canadian Nuclear Safety Commission. Pickering Nuclear also achieved the highest possible safety rating for the third year in a row. Both of these accomplishments are a reflection of OPG's commitment to protecting the public, the environment and our staff."

The International Atomic Energy Agency also confirmed that Pickering Nuclear Generation Station (GS) demonstrated strong operational safety performance. Lyash commented, "This quarter, I was pleased to hear the results of an international safety review that recognized Pickering Nuclear's safe and reliable operations. Continued strong operational safety performance will ensure we deliver on our commitment to secure Ontario's clean power future."

The Company's net income for the third quarter of 2018 was favourably impacted by the new regulated prices for OPG's nuclear and most of its hydroelectric generation, resulting from the Ontario Energy Board's decision on OPG's application for new regulated prices for the 2017-2021 period issued in December 2017. Partially offsetting the increase in earnings due to the new regulated prices, nuclear electricity generation in the third quarter of 2018 was lower compared to the same period in 2017 due to a combination of higher unplanned outage days at the Pickering GS and planned outage days at the Darlington GS.

Taking into account the impact of the new regulated prices, OPG continues to provide electricity at a price that is approximately 40 per cent less than the average of other generators in Ontario.

Generation and Operating Performance

Electricity generated during the three months ended September 30, 2018 was 18.3 terawatt hours (TWh), compared to 19.4 TWh for the same quarter in 2017. Total electricity generated during the nine months ended September 30, 2018 decreased to 54.3 TWh from 56.0 TWh for the same period in 2017.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 0.7 TWh for the third quarter of 2018, compared to the same quarter in 2017, was primarily due to a combination of increased unplanned outage days at the Pickering GS and planned outage days at the Darlington GS. The lower nuclear generation of 1.0 TWh for the nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to an increase in planned outage days at the Pickering GS in the first half of 2018 in accordance with the station's cyclical maintenance schedule, and unplanned outage days at the Pickering GS in the third quarter of 2018, partially offset by greater generation at the Darlington GS.

For the third quarter of 2018, the unit capability factor for the operating units at the Darlington GS was 91.7 per cent, compared to 96.2 per cent for the same quarter in 2017. For the nine months ended September 30, 2018, the unit capability factor for the operating units at the Darlington GS was 85.2 per cent, compared to 82.1 per cent for the same period in 2017. The decrease for the third quarter of 2018 was primarily due to a higher number of planned outage days at the station as part of the station's cyclical maintenance schedule. The increase for the nine months ended September 30, 2018 was due to fewer planned outage days at the station during the first quarter of 2018.

At the Pickering GS, the unit capability factor decreased to 87.9 per cent and 77.9 per cent for the three and nine month periods ended September 30, 2018, respectively, compared to 88.7 per cent and 83.8 per cent for the same periods in 2017. The decrease in the third quarter of 2018 was largely due to the increase in unplanned outage days at the station. The decrease in the nine months ended September 30, 2018 was primarily due to a higher number of planned outage days in the station's cyclical maintenance schedule in the first half of 2018.

Regulated – Hydroelectric Segment

Lower generation from the regulated hydroelectric stations of 0.3 TWh and 1.2 TWh during the three and nine month periods ended September 30, 2018, respectively, compared to the same periods in 2017, was primarily due to lower water flows across most river systems in the Province.

The availability of 82.6 per cent at these stations in the third quarter of 2018 was lower than 87.6 per cent for the same quarter in 2017. For the nine months ended September 30, 2018, the availability of the stations decreased to 86.1 per cent, from 89.0 per cent for the same period in 2017. The decrease in the availability was primarily due to a higher number of outage days at the eastern and northwestern Ontario regions' regulated hydroelectric stations.

Contracted Generation Portfolio Segment

Generation from the Contracted Generation Portfolio for the third quarter of 2018 was comparable to the same quarter in 2017. The increase in generation of 0.5 TWh for the nine months ended September 30, 2018, compared to the same period in 2017, was partially due to less generation forgone as a result of higher electricity market demand in Ontario in the current period.

The availability of these hydroelectric stations for the three months ended September 30, 2018 was 67.7 per cent, compared to 66.1 per cent for the same quarter in 2017. The stations' availability for the nine months ended September 30, 2018 was 78.1 per cent, compared to 76.9 per cent for the same period in 2017. The increase was primarily due to a lower number of planned outage days at the northeastern Ontario region's contracted hydroelectric stations and unplanned outage days at the northwestern Ontario region's contracted hydroelectric stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for the three months ended September 30, 2018 was $53.64, compared to $46.65 for the same quarter in 2017. The increase in Enterprise Total Generating Cost per MWh in 2018 was primarily due to the lower nuclear electricity generation as a result of a higher number of unplanned outage days at the Pickering GS and a higher number of planned outage days at the Darlington GS in 2018, lower hydroelectric electricity generation due to higher water flows in 2017, and higher sustaining capital expenditures in 2018.

The Enterprise Total Generating Cost per MWh for the nine months ended September 30, 2018 was $53.02, compared to $47.77 for the same period in 2017. The increase in Enterprise Total Generating Cost per MWh in 2018 was primarily due to an increase in planned outage days at the Pickering GS in the first half of 2018 in accordance with the station's cyclical maintenance schedule, increase in unplanned outage days at the Pickering GS in the third quarter of 2018, and lower hydroelectric electricity generation due to higher water flows in 2017, partially offset by greater generation at the Darlington GS.

Acquisition of Eagle Creek Renewable Energy

In August 2018, OPG signed a purchase and sale agreement to acquire 100 per cent of the equity of Eagle Creek Renewable Energy LLC (Eagle Creek), an operator of small hydropower facilities in the United States, for US$298 million, subject to customary working capital and other adjustments.

Eagle Creek currently owns and operates 63 small hydropower facilities representing 216 megawatts (MW) of capacity, primarily located in the U.S. Northeast and Midwest. Eagle Creek also has ownership interests in 13 other hydroelectric assets and two solar facilities in New England, representing 10 MW of capacity.

In the third quarter of 2018, OPG received Hart-Scott-Rodino Act antitrust regulatory approval, and is currently awaiting final federal regulatory approvals from the Committee on Foreign Investment in the United States (CFIUS) prior to the closing of the acquisition. The transaction is expected to close by the end of 2018.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the third quarter of 2018 included the following:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by at least 30 years. In October 2018, OPG completed the installation of new calandria tubes and is progressing as planned through the third major segment of the project, the installation and reassembly of reactor components. The installation of new fuel channels is now underway. The Darlington Refurbishment project, the execution of which began in 2016, continues to track on schedule and to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG continues to progress with the planning and prerequisite activities for the refurbishment of Unit 3, incorporating the experience learned to date on Unit 2's execution, and is continuing to enter into commitments to procure major components that require long lead times. The Unit 3 refurbishment is expected to commence upon the return to service of Unit 2. As of September 30, 2018, $213 million has been expended in planning and prerequisite activities related to the refurbishment of Unit 3.

Total life-to-date capital expenditures on the project were approximately $5.2 billion as at September 30, 2018.

Ranney Falls Hydroelectric GS

In the third quarter of 2018, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues with concrete placement of the expanded forebay, powerhouse and spillway. Sectional gates, unit head gates and spillway gates installation is in progress. The substation construction is completed, and turbine and generator unit fabrication and factory acceptance testing are in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

Sir Adam Beck 1 GS

The Sir Adam Beck 1 GS, located at Niagara Falls, was originally placed in service in the 1920s. A project to rehabilitate two of the older units at the station (G1 and G2) is in its early stages of planning. These two units used outdated technology prior to being decommissioned in 2009. The conversion of these units to newer technology is expected to add approximately 100 MW of incremental generating capacity, providing many more decades of cost effective, clean power from one of the cornerstone stations in the Company's hydroelectric fleet. Detailed cost and schedule commitment estimates are currently under development for the project.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2018**	**2017**	**2018**	**2017**
Revenue	**1,373**	1,217	**4,062**	3,539
Fuel expense	**175**	185	**496**	518
Operations, maintenance and administration	**638**	635	**2,103**	2,054
Depreciation and amortization	**200**	178	**584**	517
Other expenses (gains), net [1]	**27**	39	**(169)**	(249)
Income before interest and income taxes	**333**	180	**1,048**	699
Net interest expense	**19**	21	**56**	56
Income tax expense	**31**	19	**44**	128
Net income	**283**	140	**948**	515
Net income attributable to the Shareholder	**279**	131	**935**	498
Net income attributable to non-controlling interest [2]	**4**	9	**13**	17
Income (loss) before interest and income taxes				
Electricity generating business segments	**370**	217	**866**	436
Regulated – Nuclear Waste Management	**(26)**	(36)	**(91)**	(123)
Fair Hydro Trust	**7**	-	**19**	-
Other	**(18)**	(1)	**254**	386
Total income before interest and income taxes	**333**	180	**1,048**	699
Cash flow				
Cash flow provided by operating activities	**524**	459	**1,163**	716
Electricity generation (TWh)				
Regulated – Nuclear Generation	**10.6**	11.3	**29.6**	30.6
Regulated – Hydroelectric	**7.0**	7.3	**22.3**	23.5
Contracted Generation Portfolio [3]	**0.7**	0.8	**2.4**	1.9
Total electricity generation	**18.3**	19.4	**54.3**	56.0
Nuclear unit capability factor (per cent) [4]				
Darlington Nuclear GS	**91.7**	96.2	**85.2**	82.1
Pickering Nuclear GS	**87.9**	88.7	**77.9**	83.8
Availability (per cent)				
Regulated – Hydroelectric	**82.6**	87.6	**86.1**	89.0
Contracted Generation Portfolio – hydroelectric stations	**67.7**	66.1	**78.1**	76.9
Equivalent forced outage rate				
Contracted Generation Portfolio – thermal stations [5]	**6.4**	2.6	**2.8**	6.0
Enterprise Total Generating Cost (TGC) per MWh ($/MWh) for the three and nine months ended September 30, 2018 and September 30, 2017 ($/MWh) [6]	**53.64**	46.65	**53.02**	47.77
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended September 30, 2018 and December 31, 2017 (%) [6]			**10.8**	7.6

[1] For the nine months ended September 30, 2018, includes the pre-tax gain on the sale of the former Lakeview GS site. For the nine months ended September 30, 2017, includes the pre-tax gain on the sale of OPG's head office property.

[2] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[3] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[4] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[5] For the three and nine months ended September 30, 2018, includes unplanned outage days at the Thunder Bay GS prior to the commencement of cessation of operations in July 2018.

[6] Enterprise TGC per MWh and ROE Excluding AOCI are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three and nine month periods ended September 30, 2018, in the sections *Highlights – Return on Equity Excluding Accumulated Other Comprehensive Income*, *Highlights – Enterprise Total Generating Cost per MWh*, and *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2018 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact:	Investor Relations	416-592-6700 webmaster@opg.com
	Media Relations	416-592-4008 1-877-592-4008

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2018 THIRD QUARTER REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2018, compared to the same periods in 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, Annual Information Form, and MD&A as at and for the year ended December 31, 2017.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards (IFRS). In April 2018, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2024. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2024. For details, refer to the section, *Changes in Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP.* This MD&A is dated November 13, 2018.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management*, and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC), health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Act) and forecasts of earnings, cash flows, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC), Operations, Maintenance and Administration (OM&A) expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2018, OPG's electricity generation portfolio had an in-service capacity of 16,218 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS), and OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP. Income from these leased stations is included as revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2017 annual MD&A in the section, *Business Segments*.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of September 30, 2018 and December 31, 2017 was as follows:

(MW)	As at **September 30 2018**	 **December 31 2017**
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,426
Contracted Generation Portfolio [2]	**4,064**	4,056
Total	**16,218**	16,210

[1] The in-service generating capacity as of September 30, 2018 and December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS (Darlington GS). The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach. Also includes in-service generating capacity of 153 MW for the Thunder Bay GS, for which the Energy Supply Agreement (ESA) has been terminated.

During the nine months ended September 30, 2018, the total in-service capacity increased by 8 MW. The increase was due to the completion of the overhaul and upgrade of Unit 1 of the Harmon hydroelectric GS, which returned to service in the first quarter of 2018.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results and summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2018, compared to the same periods in 2017, are discussed below. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted)	**2018**	**2017**	**2018**	**2017**
Revenue	**1,373**	1,217	**4,062**	3,539
Fuel expense	**175**	185	**496**	518
Operations, maintenance and administration	**638**	635	**2,103**	2,054
Depreciation and amortization	**200**	178	**584**	517
Other expenses (gains), net	**27**	39	**(169)**	(249)
Income before interest and income taxes	**333**	180	**1,048**	699
Net interest expense	**19**	21	**56**	56
Income tax expense	**31**	19	**44**	128
Net income	**283**	140	**948**	515
Net income attributable to the Shareholder	**279**	131	**935**	498
Net income attributable to non-controlling interest [1]	**4**	9	**13**	17
Electricity production (TWh) [2]	**18.3**	19.4	**54.3**	56.0
Cash flow				
Cash flow provided by operating activities	**524**	459	**1,163**	716
Segment Results				
Regulated – Nuclear Generation	**179**	20	**170**	(267)
Regulated – Hydroelectric	**121**	122	**470**	474
Contracted Generation Portfolio	**70**	75	**226**	229
Total electricity generating business segments	**370**	217	**866**	436
Regulated – Nuclear Waste Management	**(26)**	(36)	**(91)**	(123)
Fair Hydro Trust	**7**	-	**19**	-
Other	**(18)**	(1)	**254**	386
Income before interest and income taxes	**333**	180	**1,048**	699

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $279 million for the third quarter of 2018, an increase of $148 million compared to the same quarter in 2017. Income before interest and income taxes for the third quarter of 2018 was $333 million, an increase of $153 million compared to the same quarter in 2017. The following summarizes the significant factors which contributed to the variance:

Significant factor that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $220 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices.

Significant factors that reduced income before interest and income taxes:

- Lower electricity generation of 0.7 terawatt hours (TWh) from the Regulated – Nuclear Generation segment, resulting in lower revenue of approximately $40 million. The lower electricity generation from the segment primarily reflected a combination of increased unplanned outage days at the Pickering Nuclear GS (Pickering GS) and planned outage days at the Darlington GS in the third quarter of 2018.
- Higher depreciation and amortization expenses of $8 million, excluding amortization expense related to the recovery of OEB-authorized regulatory variance and deferral account (regulatory account) balances, mainly due to new assets in service.
- Initial incremental costs and adjustments to asset carrying values of $6 million incurred in the Contracted Generation Portfolio segment in the third quarter of 2018, resulting from the cessation of operations as part of the closure of the Thunder Bay GS.

Net interest expense decreased by $2 million during the third quarter of 2018, compared to the same quarter in 2017, primarily due to a higher amount of interest costs capitalized related to the Darlington Refurbishment project expenditures, partially offset by a higher amount of interest costs on net debt issuances and a lower amount of interest costs deferred in regulatory accounts.

Income tax expense increased by $12 million for the three months ended September 30, 2018, compared to the same period in 2017. The increase was primarily due to higher income before taxes, partially offset by a higher amount of deferred income tax expense recorded as a regulatory asset.

Year-To-Date

Net income attributable to the Shareholder was $935 million for the first nine months of 2018, an increase of $437 million compared to the same period in 2017. Income before interest and income taxes for the first nine months of 2018 was $1,048 million, an increase of $349 million compared to the same period in 2017. The following summarizes the significant factors which contributed to the variance:

Significant factors that increased income before interest and income taxes:

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $608 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices.
- A pre-tax gain on the sale of the former Lakeview GS site of $273 million recognized in net income upon completion of the transaction in the first quarter of 2018. The sale of this non-core real estate asset was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG is required to transfer the proceeds from the disposition, net of prescribed

deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of the designated proceeds under the Trillium Trust Act to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on the sale of $205 million.

- Higher earnings of $32 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Significant factors that reduced income before interest and income taxes:

- A pre-tax gain on the sale of OPG's head office premises and associated parking facility of $378 million recorded in the second quarter of 2017. The proceeds from the disposition, net of prescribed deductions under the Trillium Trust Act, were transferred into the Province's Consolidated Revenue Fund in March 2018 in the form of a special dividend.
- Lower electricity generation of 1.0 TWh from the Regulated – Nuclear Generation segment, resulting in lower revenue of approximately $60 million. The lower electricity generation from the segment was primarily due to an increase in planned outage days at the Pickering GS in the first half of 2018 in accordance with the station's cyclical maintenance schedule, and unplanned outage days at the Pickering GS in the third quarter of 2018, partially offset by greater generation at the Darlington GS.
- Higher OM&A expenses of $49 million, primarily in the Regulated – Nuclear Generation and Regulated – Hydroelectric segments, reflecting services and materials costs associated with increased outage activity at the Pickering GS, and higher hydroelectric project expenses and increased maintenance work programs.
- Higher depreciation and amortization expenses of $34 million, excluding amortization expense related to the recovery of the regulatory account balances, mainly due to new assets in service.
- Initial incremental costs and adjustments to asset carrying values of $6 million incurred in the Contracted Generation Portfolio segment in the third quarter of 2018, resulting from the cessation of operations as part of the closure of the Thunder Bay GS.

Net interest expense for the nine months ended September 30, 2018 was comparable to the same period in 2017. The higher amount of interest costs capitalized related to the Darlington Refurbishment project expenditures was largely offset by a lower amount of interest costs deferred in regulatory accounts and a higher amount of interest costs on net debt issuances.

Income tax expense decreased by $84 million for the nine months ended September 30, 2018, compared to the same period in 2017. The decrease was primarily due to a reduction in income taxes due to a refundable tax credit of $86 million and a higher amount of deferred income tax expense recorded as a regulatory asset, partially offset by the impact of higher income before taxes.

Recent Developments

Acquisition of Eagle Creek Renewable Energy

On August 8, 2018, OPG entered into a purchase and sale agreement with Power Energy Eagle Creek, LLC and Hudson Clean Energy Partners LP to acquire 100 percent of the equity in Eagle Creek Renewable Energy LLC (Eagle Creek) for US$298 million, subject to customary working capital and other adjustments. Eagle Creek is a hydropower platform, with 226 MW of capacity spread across 76 hydroelectric facilities and two solar facilities throughout the United States, and represents an opportunity to expand OPG's renewable generation portfolio to new geographies, with additional carbon-free generation aligning to OPG's strategic imperatives. The majority of facilities within Eagle Creek's fleet have operated as merchant based plants in the New England, Michigan and New York market areas. In the third quarter of 2018, OPG received Hart-Scott-Rodino Act antitrust regulatory approval, and is currently awaiting final federal regulatory approvals from the Committee on Foreign Investment in the United States (CFIUS) prior to the closing of the acquisition. The transaction is expected to close by the end of 2018.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual report on the regulatory oversight and safety performance for nuclear power generating sites. For the first time, the CNSC's regulatory oversight report assessed the safety performance not only of Canada's nuclear power plants, but also of adjacent waste management facilities. The report assesses how well licensees are meeting regulatory requirements and program expectations in areas such as human performance, radiation and environmental protection, and emergency management and fire protection. On September 6, 2018, the CNSC issued its 2017 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory", and the Darlington, Pickering, and Western waste management facilities the safety rating of "Satisfactory". The Darlington GS achieved this rating for the ninth consecutive year, while the Pickering GS achieved this rating for the third consecutive year.

Continued Operations Plan for Pickering GS

In August 2018, OPG obtained a ten-year operating licence renewal for the Pickering GS from the CNSC, which supports the plan to extend safe and reliable commercial operation of the station to December 31, 2024 and subsequently place the station in a safe storage state by 2028. The CNSC directed that OPG present a comprehensive update on its licensed activities at the Pickering GS at the mid-point of the ten-year licence period and no later than 2023.

Termination of Thunder Bay GS Energy Supply Agreement

On July 26, 2018, OPG reached an agreement with the Independent Electricity System Operator (IESO) to terminate the ESA for the advanced biomass fuelled generating unit at the Thunder Bay GS, effective June 30, 2018. The termination of the ESA was determined to be the most cost effective alternative for electricity consumers and allowed OPG to avoid additional repair costs that would have been necessary to continue to operate the Thunder Bay GS for the remainder of the ESA term to January 2020. The termination agreement provides for payments to OPG for the remainder of 2018 to allow for the orderly cessation of activities as part of the station's closure, including disposition of fuel inventories and fuel contracts. During the third quarter of 2018, OPG provided a fuel mitigation plan to the IESO as required under the terms of the termination agreement which was subsequently approved by the IESO. OPG also commenced the de-registration process for the Thunder Bay GS with the IESO during the quarter. In October 2018, OPG received notice from the IESO approving the de-registration of the station. The station is expected to be de-registered by the end of 2018.

Response to Storm Damage at Calabogie GS

On September 21, 2018, a tornado occurred in eastern Ontario, impacting the Calabogie hydroelectric GS. Management has devised a plan to restore full control of the station's water flow equipment and is in the process of conducting a full assessment of the powerhouse and generating equipment to determine the path to restoration or redevelopment of the site.

Labour Relations

The Power Workers' Union (PWU) represents approximately 4,700 regular employees at OPG, and the Society of United Professionals (Society) represents approximately 3,000 regular employees at OPG, or approximately 52 and 36 percent, respectively, of OPG's regular workforce as at September 30, 2018.

The governing collective agreement between OPG and the PWU expired in March 2018. The parties reached a tentative renewal agreement in June 2018, but in August 2018, PWU membership did not ratify the agreement. The parties have since been unable to agree on any changes to the tentative renewal agreement, which the PWU will now again take to a membership vote for ratification. Results are expected to be known before the end of the year.

The governing collective agreement between OPG and the Society expires on December 31, 2018, and negotiations took place in mid-2018. The parties were unable to reach an agreement and proceeded to interest mediation/arbitration in October 2018. Results are expected to be known before the end of the year.

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2018 and 2017 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2018	**2017**	**2018**	**2017**
Regulated – Nuclear Generation	**10.6**	11.3	**29.6**	30.6
Regulated – Hydroelectric	**7.0**	7.3	**22.3**	23.5
Contracted Generation Portfolio [1]	**0.7**	0.8	**2.4**	1.9
Total OPG electricity generation	**18.3**	19.4	**54.3**	56.0
Total electricity generation by other generators in Ontario [2]	**19.3**	16.6	**55.8**	51.7

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation was lower by 1.1 TWh during the third quarter of 2018, compared to the same quarter in 2017, and lower by 1.7 TWh during the nine months ended September 30, 2018, compared to the same period in 2017. This decrease was due to lower electricity generation from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments, partially offset over the nine month period by higher electricity generation from the Contracted Generation Portfolio segment.

The decrease in electricity generation of 0.7 TWh from the Regulated – Nuclear Generation segment for the third quarter of 2018, compared to the same quarter in 2017, was primarily due to a combination of increased unplanned outage days at the Pickering GS and planned outage days at the Darlington GS. The decrease in electricity generation of 1.0 TWh from the Regulated – Nuclear Generation segment for the nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to an increase in planned outage days at the Pickering GS in accordance with the station's cyclical maintenance schedule, and unplanned outage days at the Pickering GS in the third quarter of 2018, partially offset by greater generation at the Darlington GS. There was a higher concentration of planned outages in the cyclical maintenance schedule at the Pickering GS for the first half of the year, which was partially offset by fewer planned outage days at the Darlington GS during the first quarter and at the Pickering GS during the third quarter of 2018. Fewer outage days are planned for the Regulated – Nuclear Generation segment for the last quarter of 2018, compared to the same quarter in 2017. The increase in unplanned outages at the Pickering GS during the third quarter of 2018 resulted from significant amounts of algae debris interfering with water intake screens following inclement weather. Affected units were safely returned to service over a period of eight days.

The decrease in electricity generation of 0.3 TWh and 1.2 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2018, respectively, compared to the same periods in 2017, was primarily due to lower water flows across most river systems in the province.

The electricity generation from the Contracted Generation Portfolio segment for the third quarter of 2018 was comparable to the same quarter in 2017. The increase in electricity generation of 0.5 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to lower electricity generation forgone as a result of SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2018, Ontario's electricity demand as reported by the IESO was 36.5 TWh and 103.5 TWh, respectively, compared to 33.6 TWh and 98.5 TWh for the same periods in 2017, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations, and other grid-connected renewable resources. Baseload generation supply surplus in Ontario has been lower in 2018 compared to 2017, resulting in total forgone hydroelectric electricity generation for OPG of 0.4 TWh and 2.4 TWh due to SBG conditions in the three and nine month periods ended September 30, 2018, respectively, compared to 1.1 TWh and 4.5 TWh during the same periods in 2017. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The new regulated prices for electricity generated from these segments approved by the OEB in its December 2017 decision and March 2018 payment amounts order, effective June 1, 2017, can be found in the section, *Core Business, Strategy, and Outlook* under the heading, *Financial Strength – Increasing Revenue, Reducing Costs and Achieving Appropriate Return* and are further discussed in OPG's 2018 First Quarter MD&A in the section, *Highlights* under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices*.

The average sales price for the Regulated – Nuclear Generation segment was 7.9 and 7.7 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2018, respectively, compared to 5.8 ¢/kWh during the same periods in 2017. The increase in the average sales price primarily reflected the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order. The increase in the average sales price during the nine months ended September 30, 2018 was partially offset by a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall recorded in the fourth quarter of 2017 to reflect management's best estimate of the impact of the OEB's December 2017 decision, based on OPG's submission of a draft payment amounts order to the OEB in January 2018. The partial reversal was recorded in the first quarter of 2018 to reflect the issuance of the final payment amounts order in March 2018, which made certain adjustments to OPG's draft payment amounts order. These adjustments did not have a material impact on the results of operations for the nine months ended September 30, 2018, as the revenue and income impact of the partial reversal of the interim period revenue shortfall regulatory asset was largely offset by the reversal of the regulatory liability for the Rate Smoothing Deferral Account recorded in the fourth quarter of 2017 based on the draft payment amounts order. Amounts deferred under rate smoothing are not included in the calculation of the average sales price until the period they are settled with ratepayers.

The average sales price for the Regulated – Hydroelectric segment was 4.4 and 4.3 ¢/kWh during the three and nine month periods ended September 30, 2018, respectively, compared to 4.1 ¢/kWh during the same periods in 2017. The higher average sales price in 2018 was mainly due to the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order.

Cash Flow from Operations

Cash flow provided by operating activities was $524 million and $1,163 million for the three and nine month periods ended September 30, 2018, respectively, compared to $459 million and $716 million for the same periods in 2017. The increase in cash flow provided by operating activities was mainly due to higher cash receipts from generation revenue reflecting the impact of the new regulated prices implemented following the issuance of the OEB's March 2018 payment amounts order, partially offset by the impact of lower electricity generation.

Return on Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for the twelve months ended September 30, 2018 was 10.8 percent, compared to 7.6 percent for the twelve months ended December 31, 2017. The increase in ROE Excluding AOCI was primarily due to higher net income attributable to the Shareholder as a result of increased revenue reflecting the impact of the new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, and the gain on the sale of the former Lakeview GS site recorded in the first quarter of 2018. ROE Excluding AOCI for the twelve months ended December 31, 2017 reflected the gain on the sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017. The gains on the sale of the former Lakeview GS site and the sale of the head office premises and associated parking facility, including the effect of the associated special dividend authorized and paid in March 2018, together with the income tax effects of these transactions, contributed approximately 2.2 percent to ROE Excluding AOCI for the twelve months ended September 30, 2018 and approximately 2.5 percent for the twelve months ended December 31, 2017, as applicable.

Enterprise Total Generating Cost per Megawatt Hour

The Enterprise TGC per megawatt hour (MWh) was $53.64 for the three months ended September 30, 2018, compared to $46.65 for the same quarter in 2017. The increase in Enterprise TGC per MWh in 2018 was primarily due to the lower nuclear electricity generation as a result of a higher number of unplanned outage days at the Pickering GS and a higher number of planned outage days at the Darlington GS in 2018, lower SBG-adjusted hydroelectric electricity generation due to higher water flows in 2017, and higher sustaining capital expenditures in 2018.

The Enterprise TGC per MWh was $53.02 for the nine months ended September 30, 2018, compared to $47.77 for the same period in 2017. The increase in Enterprise TGC per MWh in 2018 was primarily due to an increase in planned outage days at the Pickering GS in the first half of 2018 in accordance with the station's cyclical maintenance schedule, increase in unplanned outage days at the Pickering GS in the third quarter of 2018, and lower SBG-adjusted hydroelectric electricity generation due to higher water flows in 2017, partially offset by greater generation at the Darlington GS.

Nuclear Total Generating Cost per Megawatt Hour

The Nuclear TGC per MWh was $64.72 for the three months ended September 30, 2018, compared to $58.75 for the same quarter in 2017. The increase in Nuclear TGC per MWh in 2018 was primarily due to the lower nuclear electricity generation as a result of a higher number of unplanned outage days at the Pickering GS and a higher number of planned outage days at the Darlington GS in 2018, and higher sustaining capital expenditures in 2018.

The Nuclear TGC per MWh was $73.05 for the nine months ended September 30, 2018, compared to $67.87 for the same period in 2017. The increase in Nuclear TGC per MWh in 2018 was primarily due to an increase in planned outage days at the Pickering GS in the first half of 2018 in accordance with the station's cyclical maintenance schedule, and unplanned outage days at the Pickering GS in the third quarter of 2018, partially offset by greater generation at the Darlington GS, as well as higher OM&A expenses associated with this increase in outage activity.

Hydroelectric Total Generating Cost per Megawatt Hour

The Hydroelectric TGC per MWh was $31.48 and $24.87 for the three and nine month periods ended September 30, 2018, respectively, compared to $26.20 and $21.74 for the same periods in 2017. The increase in Hydroelectric TGC per MWh was primarily due to lower SBG-adjusted hydroelectric electricity generation due to higher water flows in 2017.

ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP, and should not be considered alternative measures to net income or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements*, at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder.

The following sections provide an update to OPG's disclosures in the 2017 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2017 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in a manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics. In November 2018, OPG received the Canadian Electricity Association (CEA) President's Award of Excellence for Employee Safety, recognizing OPG's top quartile safety performance within the comparator group.

Electricity Generation Production and Reliability

The status updates for OPG’s electricity generation portfolio as of September 30, 2018 are summarized below:

- In September 2018, the International Atomic Energy Agency (IAEA) conducted a follow-up operational safety review of Pickering GS. A previous review was completed in September 2016. On September 24, 2018, the IAEA confirmed in a press release that the review team noted a strong commitment to address issues identified by the September 2016 review. The team noted that several recommendations from the September 2016 review were fully implemented and significant progress has been made on several other recommendations. A draft report was provided to OPG and the CNSC, and the final report is expected by the end of this year. IAEA reviews are standard undertakings that assess operational safety performance and adherence to international safety standards.

- In August 2018, OPG and the New York Power Authority renewed the Joint Works Agreement to share the water, maintenance practices, safety experience and common operational costs and responsibilities, ensuring 15 more years of cross-border collaboration to generate clean power from the St. Lawrence River.

- OPG continues to invest prudently in the rehabilitation, overhaul and upgrades of its existing hydroelectric facilities. During the third quarter of 2018, OPG continued the execution of the automatic sluicegates system replacement at the Whitedog Falls GS, the overhaul and upgrade of Unit 2 of the Little Long GS, and the overhaul and upgrade of Unit 2 of the DeCew Falls 2 GS.

As part of the process to decommission the Lambton GS, a contract for the removal of the powerhouse and associated structures was issued in July 2018. The contractor has mobilized to site and the removal of saleable equipment, asbestos abatement and demolition activities are in progress. Demolition activities also continue for the powerhouse and associated structures of the Nanticoke GS. The costs of the decommissioning activities are charged to a previously established decommissioning provision.

Environmental Performance

In November 2018, OPG was recognized by the CEA with the 2018 Sustainable Electricity award for Commitment to Continuous Performance Improvement. This award recognizes OPG's leadership in decarbonizing the transportation sector with clean electricity.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. The status updates for OPG's major projects as of September 30, 2018 are outlined below.

Project *(millions of dollars)*	Capital expenditures Year-to-date	Capital expenditures Life-to-date	Approved budget	Expected in-service date	Current status
Darlington Refurbishment	777	5,211	12,800 [1]	First unit - 2020 Last unit - 2026	The reassembly of Unit 2 reactor components commenced in July 2018 and is in progress, with the new calandria tube installation series completed in October 2018 and the new fuel channel installation series underway. Planning activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and to the $12.8 billion budget.
Ranney Falls Hydroelectric GS	24	52	77	2019	Construction continues with concrete placement of the expanded forebay, powerhouse and spillway. Sectional gates, unit head gates and spillway gates installation is in progress. The substation construction is completed, and turbine and generator unit fabrication and factory acceptance testing are in progress. The project's expected in-service date is in the fourth quarter of 2019. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	56	59	107	2019	Construction continued during the third quarter of 2018. The main output transformer and all inverters have been safely delivered to site. The solar modules have also been delivered to site with installation onto the racking in progress. The facility is expected to be completed in the first quarter of 2019. The project is tracking on schedule and on budget.
Deep Geologic Repository for Low and Intermediate Level Radioactive Waste	7 [2]	211 [2]			In August 2017, as part of the Environmental Assessment approval process, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the SON's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG continues its engagement with the SON towards securing support for the project and to formulate a response to the information request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS, including the costs of the pre-requisite projects in support of the execution phase of the refurbishment. Project costs that do not meet capitalization criteria are charged to OM&A expenses in the period incurred.

[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by at least 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the prerequisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026.

OPG commenced the refurbishment of the first unit, Unit 2, in October 2016. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in the first half of 2017, signifying the completion of the first major segment of the Unit 2 refurbishment.

The second major segment included the disassembly and removal of the existing reactor components. In May 2018, OPG completed the removal of the reactor components, which included end fittings, pressure tubes and calandria tubes, signifying the completion of the second major segment of the Unit 2 refurbishment.

The Unit 2 refurbishment is now in the third major segment, the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies. In June 2018, OPG completed inspections and cleaning on the reactor vessel in preparation for the reassembly of the reactor components, and in July 2018, commenced the reassembly of Unit 2. The third segment is progressing as planned, with the new calandria tube installation series completed in October 2018 and the new fuel channel installation series underway. To date, 21 out of a total of 22 systems have been returned to service in preparation for the first Restart Control Hold Point (RCHP). The last system required for the first RCHP is expected to be returned to service before the end of the year. Construction activities on the Heavy Water Storage and Drum Handling Facility are continuing.

The planning and prerequisite activities for the refurbishment of the second unit, Unit 3, continue to progress in accordance with the overall project schedule, incorporating experience learned to date from the Unit 2 refurbishment. OPG is continuing to enter into commitments to procure major components that require long lead times. Receipt of long lead materials for the Re-tube and Feeder Replacement of Unit 3 has begun, as has construction on the Full Scale Maintenance Simulator for the turbine generator. The Unit 3 refurbishment execution is expected to commence upon the return to service of Unit 2. As of September 30, 2018, $213 million has been expended in planning and prerequisite activities related to the Unit 3 refurbishment.

The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

Sir Adam Beck 1 GS

The Sir Adam Beck 1 GS, located at Niagara Falls, was originally placed in service in the 1920s. A project to rehabilitate two of the older units at the station (G1 and G2) is in its early stages of planning. These two units used outdated technology prior to being decommissioned in 2009. The conversion of these units to newer technology is expected to add approximately 100 MW of incremental generating capacity, providing many more decades of cost effective, clean power from one of the cornerstone stations in the Company's hydroelectric fleet. Detailed cost and schedule commitment estimates are currently under development for the project.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking continued efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and growth of the asset base earning a return as part of the regulated prices.

The OEB's December 2017 decision and March 2018 payment amounts order on OPG's 2017-2021 rate application establishing new regulated prices effective June 1, 2017 provide substantial price certainty for the regulated business up to 2021. While the OEB set costs for determining the new regulated prices below OPG's forecasted levels, including through the use of stretch factors under incentive ratemaking, the new regulated prices will result in a substantial increase in revenue and net income compared to the previously approved prices.

The regulated prices authorized by the OEB's December 2017 decision and March 2018 payment amounts order are as follows:

($/MWh)	**2017 June 1 to December 31**	**2018**	**2019**	**2020**	**2021**
Regulated – Nuclear Generation					
Base regulated price	77.96	78.64	77.00	85.00	89.70
Interim period shortfall rider [1]	-	2.89	7.71	5.64	-
Variance and deferral account rate rider [2]	-	1.05	2.79	2.04	-
	77.96	82.58	87.50	92.68	89.70
Regulated – Hydroelectric					
Base regulated price [3]	41.67	42.05	n/a	n/a	n/a
Interim period shortfall rider [1]	-	0.13	0.35	0.24	-
Variance and deferral account rate rider [2]	-	0.52	1.44	1.01	-
	41.67	42.70	n/a	n/a	n/a

[1] As part of the payment amounts order process, the OEB authorized separate rate riders to allow for the recovery of the revenue shortfall between the new base regulated prices and the previously approved base regulated prices that OPG continued to receive during the interim period between June 1, 2017 and February 28, 2018, over the March 1, 2018 to December 31, 2020 period. The revenue shortfall was recorded as a regulatory asset in the fourth quarter of 2017 and the first quarter of 2018.

[2] Variance and deferral account riders reflect OEB's approval to recover the balances recorded in regulatory accounts as at December 31, 2015 that were requested for disposition in OPG's 2017-2021 rate application.

[3] Base regulated prices for the regulated hydroelectric facilities for the 2019-2021 period will be determined annually through a formulaic adjustment using the OEB-approved incentive regulation formula and OEB-published inflation indices.

On January 17, 2018, OPG filed a motion asking the OEB to review and vary the December 2017 decision in relation to the approval of an effective date of June 1, 2017 for the new regulated prices rather than the January 1, 2017 effective date requested in OPG's application. On August 30, 2018, the OEB released its decision that denied OPG's motion. As OPG had recognized the impact of the OEB's December 2017 and March 2018 payment amounts order on the basis of the June 1, 2017 effective date, the motion decision did not impact OPG's reported financial results for the three and nine months ended September 30, 2018.

Consistent with the OEB's December 2017 decision, on August 9, 2018, OPG filed an application with the OEB requesting disposition of the Pension & OPEB Cash to Accrual Differential Deferral Account balance as at December 31, 2017, as well as balances accumulated between January 1, 2016 and December 31, 2017 in other variance and deferral accounts. OPG requested the disposition of these balances through incremental nuclear and regulated hydroelectric rate riders commencing January 1, 2019. If approved by the OEB, these rate riders will contribute to improved cash flow from operating activities but will not have a material impact on net income, as the revenue from the recovery of the regulatory balances will be largely offset by amortization expense related to the regulatory assets and regulatory liabilities for these balances. In this application, OPG also applied for the annual formulaic adjustment to set the 2019 base regulated price for the regulated hydroelectric facilities. The decision on OPG's application will be made by the OEB following a public hearing process, which commenced in September 2018.

To further improve the financial strength of the regulated operations, OPG continues to focus on optimizing operational performance and outage plans across the generating fleet and to pursue further efficiency improvements in the Company's cost structure and operating model. This includes continuing to progress the multi-year OPG25 initiative, which involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering GS commercial operation in 2024.

Ensuring Availability of Cost Effective Funding

In April 2018, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2018, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG believes in building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with Indigenous communities. OPG seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of Indigenous communities.

On August 13, 2018, OPG held a reception for the recipients of the 2018 John Wesley Beaver Memorial (JWBM) Awards. The JWBM Award was founded in 1997 by the Indigenous Circle, whose members are comprised of Indigenous employees at OPG. Each year, the JWBM Award is given to one Indigenous male and one Indigenous female postsecondary student who demonstrates leadership and involvement in their communities.

In September 2018, OPG's participation in the Progressive Aboriginal Relations program (PAR) as a member of the Canadian Council for Aboriginal Business was assessed with a Silver certification. The certification is achieved by companies that demonstrate placing high value on the importance of positive relationships and partnerships with Aboriginal communities and businesses.

In October 2018, OPG and the Mohawk Council of Akwesasne (MCA) held an event to celebrate the ten-year anniversary of signing of the final settlement agreement between OPG and the MCA. The agreement was an important step in addressing the historical impacts to the Mohawks of Akwesasne related to the construction of the R.H. Saunders hydroelectric GS.

OPG's commitment in the area of Indigenous relations also includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements and other joint projects. In addition to the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand River, OPG has been working with the Kiashke Zaaging Anishinaabek (KZA), also known as the Gull Bay First Nation, to construct a new renewable micro grid that will utilize solar generation, battery storage, and micro grid control technology to reduce the community's reliance on diesel generation. As the lead developer of the project, OPG is working with several collaborators to construct the micro grid on KZA reserve land. In collaboration with the KZA, construction commenced in the third quarter of 2018 and will continue through the year. Following testing and commissioning, the micro grid will be transferred to KZA for ownership and operation in 2019. The micro grid project is OPG's fifth development project in partnership with an Indigenous community.

OPG is committed to undertaking proactive engagement and consultation with Indigenous communities on its new projects and is currently undertaking early community information sessions with the Moose Cree First Nation and the Taykwa Tagamou Nation on a planned project to strengthen dam safety on the Lower Mattagami River.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of the Company's applications for regulated prices to the OEB.

In 2018, the full-year effect of the new regulated prices established by the OEB's December 2017 decision and March 2018 payment amounts order will contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results. An improvement in cash flow from operating activities is also expected in 2018 as a result of the new regulated prices, including from the collection of the interim period revenue shortfall for the June 1, 2017 to February 1, 2018 period.

Several regulatory accounts will continue to reduce the relative variability of the Company's net income and ROE Excluding AOCI. Among others, these accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on continuing to strengthen the overall reliability and predictability of the fleet. Taking into account outage activity planned at the nuclear generating stations during the remainder of the year, OPG expects a year-over-year increase in earnings from the Regulated – Nuclear segment in 2018.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO or other long-term contracts. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities during the remainder of 2018.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC measures for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures, nuclear outage profile and water flows may also impact TGC measures in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by earnings on the Nuclear Segregated Funds established under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, which are reported in the Regulated – Nuclear Waste Management segment. Variations in rates of return for the funds based on financial market conditions, including changes in the Ontario consumer price index (CPI) that affect earnings on the portion of the Used Fuel Segregated Fund guaranteed by the Province, can be volatile and cause fluctuations in the Company's income in the near term. This volatility is reduced by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and during periods when the funds are in a fully funded or overfunded position. As at September 30, 2018, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by approximately one percent, based on the current ONFA reference plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's current results include the earnings and operating cash flow from the Fair Hydro Trust segment, primarily related to interest income from the Fair Hydro Trust (the Trust). The future financial impact of OPG's involvement with the Trust is expected to be significantly reduced once the Province's September 2018 announcement to cancel the Global Adjustment refinancing component of Ontario's Fair Hydro Plan (Fair Hydro Plan) is implemented, as discussed in the section, *Discussion of Operating Results by Business Segment*.

ENVIRONMENTAL, SOCIAL, GOVERNANCE, AND SUSTAINABILITY

OPG is in the process of developing its Environmental, Social, Governance (ESG), and Sustainability framework to best reflect and disclose information that is meaningful to stakeholders. OPG plans to structure its ESG and Sustainability framework around four core themes:

- **Metrics and targets** to assess and manage relevant climate-related risks and opportunities;
- **Risk management** processes to identify, assess and manage climate-related risks and opportunities;
- **Strategy** for incorporating climate change impacts into business planning and decision-making; and
- **Governance** for integrating the climate change strategy in the business.

In developing its ESG and Sustainability framework, OPG expects to leverage industry-specific and other emerging guidance on best practices related to ESG and Sustainability reporting and continues to monitor the Canadian Securities Administrators' project to review the disclosures of risks and financial impacts associated with climate change.

In October 2018, OPG confirmed its support for the Financial Stability Board's Task Force for Climate-related Financial Disclosures (TCFD), and continues to determine the most relevant climate-related impacts on the business in the evolution of the ESG and Sustainability framework. Developments in OPG's ESG and Sustainability activities during the quarter included the following:

Metrics and Targets

In October 2018, OPG released its annual sustainability report which discloses metrics and targets related to environmental performance in such priority sustainability areas as greenhouse gas emissions, nuclear emissions, and environmental compliance and spills. During the quarter, initial steps were taken to identify the appropriate metrics and targets that may be considered relevant to external stakeholders with respect to the impact of climate change on OPG's financial performance and sustainability that are in addition to the metrics and targets that are disclosed in the annual sustainability report. The metrics and targets will continue to evolve as the best practices and reporting standards in the industry continue to develop. The expected timeline for development of longer-term quantitative metrics and targets is in line with peers in the industry.

Risk Management

OPG has been engaged in activities to increase the level of awareness and understanding of climate change adaptation. In recent years, Ontario has experienced unprecedented changes in climate and an increase in extreme weather events. Changes in precipitation patterns and intensity, water temperatures, and ambient air temperatures all impact various aspects of OPG's operations and the environment in the host communities. In addition to the potential impacts on electricity production at hydroelectric stations and cooling water efficiency at nuclear and thermal stations, changes in climate may also significantly affect the reliability and life expectancy of major equipment and Ontario's electricity supply and demand profile. Initiatives are underway to incorporate consideration of changes in climate into business processes. Internal workshops have commenced to identify impacts by climate parameters to support the prioritization of adaptation needs.

OPG continues to participate in industry-wide initiatives and working groups to increase of resilience of critical infrastructure. These activities include the development of a standardized process for developing climate change adaptation plans and proposed changes to the Canadian Electrical Code.

In September 2018, the Province announced that a climate change plan will be released by the end of 2018. OPG will be monitoring developments in this area to determine the impact on OPG's operations, and assess how OPG's current climate change strategy aligns with the Province's plan.

Strategy

In August 2018, OPG entered into a purchase and sales agreement for the acquisition of Eagle Creek, an owner of and operator of small hydropower facilities in the United States. The acquisition further supports the integration of environmental and climate change strategy into OPG's business strategy and core business decisions.

In November 2018, OPG submitted an updated climate change strategy to the Board of Directors for approval. OPG's updated climate strategy will provide an integrated view of all relevant activities and initiatives across the Company. The strategy will aim to demonstrate OPG's ongoing leadership in supporting Ontario's economy, help Ontario achieve its environmental goals and position OPG as a trusted voice in transforming North America's electricity sector. OPG's updated climate change strategy is aligned with the recommendations made by the TCFD.

Governance

During the third quarter of 2018, OPG's ESG and Sustainability steering committee, consisting of expertise in the areas of finance, environment, social relations and governance, convened for the second time, having been established in May 2018. The committee continues to provide oversight on integrating identified climate-related risks and opportunities within the Company's long-term strategy and business plan, including in areas such as capital expenditures and allocation of capital, areas of growth and opportunity for the business, and identification of at-risk assets as a result of climate change.

In addition to the climate-related impacts above, in July 2018, OPG's Board of Directors formally adopted a Board Diversity and Inclusion Policy as a key policy statement of the Board. The Policy outlines OPG's commitment to ensuring a broader range of expertise within its Board, aligning with the diversity initiatives undertaken by the Canadian Securities Administrators.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Revenue	**898**	739	**2,512**	2,000
Fuel expense	**73**	81	**208**	217
Gross margin	**825**	658	**2,304**	1,783
Operations, maintenance and administration	**507**	511	**1,731**	1,693
Depreciation and amortization	**131**	116	**382**	333
Property taxes	**8**	7	**21**	20
Income (loss) before other losses, interest, and income taxes	**179**	24	**170**	(263)
Other losses	**-**	4	**-**	4
Income (loss) before interest and income taxes	**179**	20	**170**	(267)

Income before interest and income taxes from the segment increased by $159 million and $437 million for the three and nine month periods ended September 30, 2018, respectively, compared to the same periods in 2017. The increase in earnings was primarily a result of the new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, which increased revenue by $210 million and $585 million for the three and nine month periods ended September 30, 2018, respectively. This increase was partially offset by lower electricity generation from the segment, which resulted in a decrease in revenue of $40 million and $60 million for the three and nine month periods ended September 30, 2018, respectively.

OM&A expenses decreased by $4 million during the third quarter of 2018 and increased by $38 million during the nine months ended September 30, 2018, compared to the same periods in 2017, primarily due to a higher concentration of planned outage days in the cyclical maintenance schedule at the Pickering GS in the first half of 2018, compared to 2017, resulting in higher services and materials costs in the first half of 2018 and lower services and materials costs in the remainder of 2018.

Higher depreciation and amortization expenses of $5 million and $26 million, excluding amortization expense related to the recovery of regulatory account balances, in the three and nine month periods ended September 30, 2018, respectively, compared to the same periods in 2017, were mainly due to increased depreciation from new assets in service. The increase in amortization expense related to regulatory account balances was largely offset by an increase revenue from the nuclear rate rider authorized in the OEB's December 2017 decision and March 2018 payment amounts order for the recovery of these balances.

In the fourth quarter of 2017, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 to December 31, 2022 for Units 1 and 4 and to December 31, 2024 for Units 5 to 8, and recorded a corresponding change in the nuclear asset retirement obligation and associated asset retirement costs capitalized as part of the carrying value of property, plant and equipment, effective December 31, 2017. The decrease in depreciation expense associated with this change in the end-of-life assumptions during the three and nine month periods ended September 30, 2018 was offset by the impact of regulatory accounts, including the new Impact Resulting from Changes to Pickering Station End-of-Life Dates Deferral Account authorized by the OEB.

The Unit Capability Factors for the Darlington GS and Pickering GS were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	**2017**	**2018**	**2017**
Unit Capability Factor *(%)* [1]				
Darlington GS	**91.7**	96.2	**85.2**	82.1
Pickering GS	**87.9**	88.7	**77.9**	83.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS decreased during the third quarter of 2018 and increased during the nine months ended September 30, 2018, compared to the same periods in 2017, primarily due to the impact of the station's cyclical maintenance schedule which had more planned outage days for the third quarter of 2018 and fewer planned outage days in the first quarter of 2018.

The decrease in the Unit Capability Factor at the Pickering GS during the third quarter of 2018 was largely due to an increase in unplanned outage days at the station after significant amounts of algae debris interfered with water intake screens following inclement weather. The decrease during the nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to a higher number of planned outage days in the station's cyclical maintenance schedule in the first half of 2018.

Regulated – Nuclear Waste Management Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Revenue	**33**	33	**98**	90
Operations, maintenance and administration	**33**	35	**98**	96
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**242**	230	**729**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(216)**	(196)	**(638)**	(579)
Loss before interest and income taxes	**(26)**	(36)	**(91)**	(123)

The segment loss before interest and income taxes was $26 million and $91 million during the three and nine month periods ended September 30, 2018, respectively, representing an increase in earnings of $10 million and $32 million compared to the same periods in 2017. The improvement in segment earnings was primarily a result of higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

The increase in earnings from the Nuclear Segregated Funds resulted from a higher amount of fund earnings deferred in regulatory accounts in 2017, due to fund earnings not included in the nuclear base regulated price in effect prior to the OEB's December 2017 decision, and the growth rate in the present value of the underlying funding liabilities per the current approved ONFA reference plan in effect since January 1, 2017. As the Decommissioning Segregated Fund and the Used Fuel Segregated Fund were in an overfunded position since the beginning of 2017, they were not impacted by market returns and the rate of return guaranteed by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA reference plan. Further details on the accounting for the Nuclear

Segregated Funds can be found in OPG's 2017 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The increase in accretion expense on the Nuclear Liabilities was mainly due to a higher amount of accretion expense deferred in regulatory accounts in 2017, due to costs not included in the nuclear base regulated price in effect prior to the OEB's December 2017 decision.

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Revenue [1]	**331**	327	**1,077**	1,069
Fuel expense	**87**	88	**242**	258
Gross margin	**244**	239	**835**	811
Operations, maintenance and administration	**83**	81	**245**	232
Depreciation and amortization	**39**	34	**115**	103
Property tax	**1**	1	**1**	1
Income before other losses, interest and income taxes	**121**	123	**474**	475
Other losses	**-**	1	**4**	1
Income before interest and income taxes	**121**	122	**470**	474

[1] During both the three and nine month periods ended September 30, 2018, the Regulated – Hydroelectric segment revenue included incentive payments of $8 million related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2017 – incentive payments of $4 million and $9 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Income before interest and income taxes from the segment decreased by $1 million during the third quarter of 2018, compared to the same quarter in 2017. The decrease in earnings was mainly a result of higher forgone generation that is not subject to recovery through OEB-approved regulatory accounts in the third quarter of 2018. The decrease in earnings from the segment was largely offset by an increase in revenue of approximately $10 million to reflect the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order.

The decrease in segment income before interest and income taxes of $4 million during the nine months ended September 30, 2018, compared to the same period in 2017, was mainly a result of higher forgone generation that is not subject to recovery through OEB-approved regulatory accounts. The decrease in earnings from the segment was partially offset by an increase in revenue of approximately $23 million to reflect the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	**2017**	**2018**	**2017**
Hydroelectric Availability *(%)*	**82.6**	87.6	**86.1**	89.0

The Hydroelectric Availability decreased in the three and nine month periods ended September 30, 2018, compared to the same periods in 2017, primarily due to a higher number of outage days at the eastern and northwestern Ontario regions' regulated hydroelectric stations.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Revenue	**142**	141	**440**	431
Fuel expense	**15**	15	**46**	42
Gross margin	**127**	126	**394**	389
Operations, maintenance and administration	**43**	39	**127**	118
Depreciation and amortization	**21**	20	**60**	59
Accretion on fixed asset removal liabilities	**2**	3	**6**	7
Property taxes	**1**	-	**5**	5
Income from investments subject to significant influence	**(12)**	(11)	**(32)**	(29)
Income before other losses, interest and income taxes	**72**	75	**228**	229
Other losses	**2**	-	**2**	-
Income before interest and income taxes	**70**	75	**226**	229

Income before interest and income taxes from the segment decreased by $5 million and $3 million during the three and nine month periods ended September 30, 2018, respectively, compared to the same periods in 2017. The decrease in earnings was primarily due to initial incremental costs and adjustments to asset carrying values of $6 million incurred in the third quarter of 2018 on the cessation of operations as part of the closure of the Thunder Bay GS.

The decrease in earnings during the nine months ended September 30, 2018, compared to the same period in 2017, was partially offset by revenue generated from the Peter Sutherland Sr. hydroelectric GS that was placed in-service at the end of the first quarter of 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	**2017**	**2018**	**2017**
Hydroelectric Availability *(%)*	**67.7**	66.1	**78.1**	76.9
Thermal EFOR *(%)* [1]	**6.4**	2.6	**2.8**	6.0

[1] For the three and nine month periods ended September 30, 2018, includes unplanned outage days at the Thunder Bay GS prior to the commencement of cessation of operations in July 2018.

The Hydroelectric Availability increased during the three and nine month periods ended September 30, 2018, compared to the same periods in 2017. The increase was primarily due to a lower number of planned outage days at the northeastern Ontario region's contracted hydroelectric stations and unplanned outage days at the northwestern Ontario region's contracted hydroelectric stations.

The Thermal EFOR increased during the three months ended September 30, 2018, compared to the same quarter in 2017. The increase was primarily due to a higher number of unplanned outage days at the Thunder Bay GS prior to the commencement of cessation of operations in July 2018, partially offset by a lower number of planned outage days at the Lennox GS.

The lower Thermal EFOR during the nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to a lower number of unplanned and planned outage days at the Lennox GS, partially offset by a higher number of unplanned outage days at the Thunder Bay GS prior to the commencement of cessation of operations in July 2018.

Fair Hydro Trust Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Operations, maintenance and administration	**1**	-	**1**	-
Earnings from Fair Hydro Trust	**(8)**	-	**(20)**	-
Income before interest and income taxes	**7**	-	**19**	-

The Fair Hydro Trust was established in December 2017 as the financing entity contemplated by the Fair Hydro Act, for the purpose of acquiring Investment Interests from the IESO, being the irrevocable right to recover Global Adjustment costs deferred by the IESO under the Fair Hydro Act and associated financing and other costs. In order for the Trust to finance such acquisitions, it incurs senior debt from capital markets and subordinated debt from OPG. The Company consolidates the financial results of the Trust in accordance with US GAAP. Earnings from Fair Hydro Trust primarily comprise interest income, partially offset by interest costs on debt incurred by OPG to fund purchases of the Trust's subordinated debt.

In September 2018, the Province announced its intention to make future proposed legislative changes to the Fair Hydro Act to cancel the Global Adjustment refinancing component of the Fair Hydro Plan. The Province also announced that all debt issued under the Fair Hydro Trust, including the subordinated debt issued to OPG, will remain outstanding. The Province stated that it intends to fund all of the Trust's obligations issued and outstanding as of the date the limited guarantee is invoked. No future debt issuances are expected to be made by the Trust. The limited guarantee was provided by the Province to specified creditors of the Trust and is triggered by certain events, including through changes made to the Fair Hydro Act that would adversely affect the Trust's ability to meet its payment obligations.

During the three months ended September 30, 2018, there were no Investment Interest acquisitions or debt issuances undertaken by the Fair Hydro Trust, and no future debt issuances are expected to be made. OPG will continue to monitor any developments to the Fair Hydro Act and related regulations.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's current financing arrangements.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuances. These sources are used for multiple purposes, including investment in plants and technologies, funding to undertake major projects and acquisitions, funding long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, making payments under the OPEB plans, funding expenditures on the Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, servicing and repaying long-term debt, and providing general working capital.

Changes in cash, cash equivalents and restricted cash for the three and nine month periods ended September 30, 2018 and 2017 were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Cash, cash equivalents and restricted cash, beginning of period	**585**	242	**234**	186
Cash flow provided by operating activities	**524**	459	**1,163**	716
Cash flow used in investing activities	**(489)**	(437)	**(1,632)**	(738)
Cash flow (used in) provided by financing activities	**(99)**	16	**756**	116
Net (decrease) increase in cash, cash equivalents and restricted cash	**(64)**	38	**287**	94
Cash, cash equivalents and restricted cash, end of period	**521**	280	**521**	280

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Cash flow used in investing activities during the third quarter of 2018 was $489 million, compared to $437 million for the same quarter in 2017. Cash flow used in investing activities during the nine months ended September 30, 2018 was $1,632 million, compared to $738 million for the same period in 2017.

The increase in cash flow used in investing activities for the third quarter of 2018, compared to the same quarter in 2017, was primarily due to higher capital expenditures on the construction of the Nanticoke solar facility and investments in equipment at the Darlington GS, including heat exchangers and emergency power generators, partially offset by lower expenditures on the Darlington Refurbishment project. The increase in cash flow used in investing activities for the nine months ended September 30, 2018, compared to the same period in 2017, was primarily due to the purchases of Investment Interests from the IESO by the Fair Hydro Trust during the first and second quarters of 2018, and the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017. The increase in cash flow used in investing activities for the nine months ended September 30, 2018, compared to the same period in 2017, was partially offset by the receipt of proceeds from the sale of the former Lakeview GS site in March 2018.

Financing Activities

As at September 30, 2018, long-term debt outstanding including the Fair Hydro Trust's senior debt reported on OPG's interim consolidated balance sheets was $7,320 million, with $303 million representing amounts due within one year. The balance included $1,400 million outstanding under OPG's $2,350 million general corporate credit facility agreement with the OEFC that expires on December 31, 2018. The Fair Hydro Trust's senior debt outstanding was $912 million as at September 30, 2018.

Equity Financing

In March and April 2018, OPG issued 4,627,343 and 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injections in OPG, generating proceeds of $202 million and $66 million, respectively.

Corporate Financing, OEFC and Public Debt Offerings

During the first quarter of 2018, OPG issued a total of $600 million senior notes payable to the OEFC maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent. During the second quarter of 2018, OPG issued $450 million senior notes under its Medium Term Notes Program, maturing in 2048. The effective and coupon interest rates on these notes were 3.92 percent and 3.84 percent, respectively. The notes were issued under OPG's Green Bond Framework to provide funding for eligible hydroelectric projects.

Credit Facility and Project Financing

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. There were no amounts outstanding under the bank credit facility as at September 30, 2018.

As at September 30, 2018, short-term debt outstanding was $68 million, representing external commercial paper outstanding under Lower Mattagami Energy Limited Partnership's commercial paper program.

Fair Hydro Trust

In September 2018, the Province announced its intention to make future proposed legislative changes to the Fair Hydro Act to cancel the Global Adjustment refinancing component of the Fair Hydro Plan, as discussed in the section, *Discussion of Operating Results by Business Segment* under the heading, *Fair Hydro Trust Segment*. Detailed below are the debt financing arrangements currently in place for the Fair Hydro Trust. OPG will continue to monitor any developments to the Fair Hydro Act and related regulations.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving senior warehouse facility agreement expiring in December 2019. During the third quarter of 2018, there were no borrowings issued under this facility and as at September 30, 2018, there were outstanding senior notes of $12 million. In October 2018, the capacity of the facility was decreased to $12 million as a result of the Province's September 2018 announcement.

In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust to provide a portion of the funding requirement for its first purchase of Investment Interest from the IESO in December 2017. In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility after the acquisition of Investment Interest in April 2018. The Province announced in September 2018 that all debt issued by the Fair Hydro Trust will remain outstanding, and has stated that it will be responsible for making all interest and principal payments due on these bonds in the future. The Province also announced that it intends to fund all obligations of the Trust that are issued and outstanding as of the date the guarantee is invoked. No future debt issuances are expected to be made by the Trust.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2018, with an effective date of January 1, 2018. The annual funding requirements in accordance with the new actuarial valuation are $195 million for 2018, $199 million for 2019, and $203 million for 2020. The next actuarial valuation must have an effective date no later than January 1, 2021.

BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

(millions of dollars)	**As At September 30 2018**	**As At December 31 2017**
Property, plant and equipment – net	**22,101**	21,322
The increase was primarily due to capital expenditures on the Darlington Refurbishment and other projects, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**17,287**	16,724
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Long-term debt *(current and non-current portions)*	**7,295**	6,319
The increase was primarily due to the issuance of senior notes payable by the Fair Hydro Trust, senior notes payable to the OEFC, and the issuance of senior notes payable under the Company's Medium Term Note Program. The increase was partially offset by debt repayments.		
Fixed asset removal and nuclear waste management liabilities	**21,046**	20,421
The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to OPG's audited consolidated financial statements as at and for the year ended December 31, 2017. A discussion of recent accounting pronouncements and changes in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2018. Disclosure regarding OPG's critical accounting policies is included in OPG's 2017 annual MD&A.

Exemptive Relief for Reporting under US GAAP

In April 2018, OPG received an extension to its exemptive relief from the OSC requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than IFRS, without becoming a Securities and Exchange Commission registrant. This exemption replaces the exemptive relief received by OPG from the OSC in February 2014. The exemption will terminate on the earliest of the following:

- January 1, 2024;
- the financial year that commences after OPG ceases to have activities subject to rate regulation; and
- the effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

The IASB's current standard-setting project related to entities with rate-regulated activities is ongoing.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2017 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Operational Excellence

Labour Relations

The governing collective agreement between OPG and the PWU expired in March 2018. Before the end of 2018, the PWU will be taking a second membership vote for ratification of the tentative renewal agreement reached in June 2018. The governing collective agreement between OPG and the Society expires on December 31, 2018. The parties have proceeded to interest mediation/arbitration.

The outcome of negotiations with the PWU and interest mediation/arbitration with the Society may have adverse financial or reputational implications for OPG. In the event of a labour disruption by the PWU, OPG has contingency plans in place to mitigate the impact. The Society does not have a right to strike or lock-out.

Risks to Maintaining Financial Strength

Ontario's Fair Hydro Plan

Given OPG's role as the Financial Services Manager of the Trust, the proposed legislative changes to the Fair Hydro Act announced by the Province in September 2018 may impact OPG's reputation through stakeholder opinions related to its involvement in the Fair Hydro Plan. OPG will continue to monitor any developments to the Fair Hydro Act and related regulations.

Rate Regulation

OPG records certain differences between the OEB-approved revenue requirements and its actual results in OEB-authorized deferral and variance accounts. The recovery of balances in these accounts is subject to future review by the OEB. In August 2018, OPG filed an application requesting recovery of approved balances as at December 31, 2017 in the deferral and variance accounts, less amounts previously approved for recovery. There is inherent uncertainty associated with the outcome of proceedings for the recovery and refund of these balances. OPG also applied for an annual increase in 2019 for output from its rate regulated hydroelectric facilities based on an OEB approved formula. The OEB will hold a public hearing to disposition OPG's application.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2018 [1]	**2019**	**2020**
Estimated fuel requirements hedged [2]	78%	75%	76%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2018 and forecast for the remainder of the year.

[2] Represents the approximate portion of MWh of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to rate regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in or tied to US dollars. To manage this risk, OPG periodically employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at September 30, 2018, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2018, the VaR utilization ranged between nil and $0.1 million.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit exposure relating to energy markets transactions as at September 30, 2018 was $437 million, including $422 million to the IESO. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $15 million remaining exposure as at September 30, 2018, over 95 percent was with investment grade counterparties. Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the outstanding common shares and Class A shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited (Hydro One), the IESO, and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As a wholly owned government business enterprise of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2018		**2017**	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	2	-
Services	**-**	**2**	-	3
Dividends	**1**	**-**	2	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**(39)**	-	(44)
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**(48)**	-	(39)
Hydroelectric gross revenue charge	**-**	**24**	-	27
ONFA guarantee fee	**-**	**-**	-	2
Other	**-**	**-**	-	2
OEFC				
Hydroelectric gross revenue charge	**-**	**61**	-	62
Interest expense on long-term notes	**-**	**38**	-	40
Income taxes	**-**	**58**	-	23
IESO				
Electricity related revenue	**1,300**	**-**	1,122	-
Fair Hydro Trust	**19**	**-**	-	-
	1,322	**96**	1,126	76

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2018 and December 31, 2017, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,597 million and $4,462 million, respectively.

	Nine Months Ended September 30			
	2018		2017	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	7	-
Services	**-**	**9**	1	8
Dividends	**5**	**-**	6	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**63**	-	164
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**72**	-	217
Hydroelectric gross revenue charge	**-**	**80**	-	84
ONFA guarantee fee	**-**	**-**	-	6
Other	**-**	**-**		3
OEFC				
Hydroelectric gross revenue charge	**-**	**156**	-	156
Interest expense on long-term notes	**-**	**112**	-	122
Income taxes	**-**	**152**	-	132
IESO				
Electricity related revenue	**3,694**	**-**	3,217	-
Fair Hydro Trust	**47**	**-**	-	-
	3,754	**644**	3,231	892

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2018 and December 31, 2017, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,597 million and $4,462 million, respectively.

The receivables, financing receivables, equity securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars)	**September 30 2018**	**December 31 2017**
Receivables from related parties		
Hydro One	**1**	1
IESO - Electricity related receivables	**422**	354
IESO - Fair Hydro Trust [1]	**2**	7
OEFC	**5**	-
PEC	**2**	4
Province of Ontario	**3**	3
Financing receivables		
IESO - Fair Hydro Trust	**1,788**	1179
Equity securities		
Hydro One shares	**148**	188
Accounts payable and accrued charges		
Hydro One	**4**	1
OEFC	**35**	52
Province of Ontario	**8**	9
IESO - Electricity related payables	**5**	11
IESO - Fair Hydro Trust	**13**	3
Long-term debt (including current portion)		
Notes payable to OEFC	**3,420**	3195

[1] Balance consists of unbilled cost recovery revenue.

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2018, the Nuclear Segregated Funds held $1,414 million of Province of Ontario bonds (December 31, 2017 – $1,502 million) and no Province of Ontario treasury bills (December 31, 2017 – $9 million). As at September 30, 2018, the registered pension fund did not hold Province of Ontario bonds or treasury bills (December 31, 2017 − $1 million of Province of Ontario treasury bills). The Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In March and April 2018, the Fair Hydro Trust purchased Investment Interests from the IESO for an exchange amount of $460 million and $149 million, respectively, which have been classified as financing receivables on OPG's unaudited interim consolidated balance sheets. The transactions were settled in cash using proceeds from the Trust's issuance of senior debt to third parties and subordinated debt to OPG.

In September 2018, the Province announced its intention to make future proposed legislative changes to the Fair Hydro Act to cancel the Global Adjustment refinancing component of the Fair Hydro Plan. In addition, the Province stated that it intends to fund all of the Trust's obligations issued and outstanding as of the date the limited guarantee is invoked. No future debt issuances are expected to be made by the Trust. The limited guarantee was provided by the Province to specified creditors of the Trust and is triggered by certain events, including through changes made to the Fair Hydro Act that would adversely affect the Trust's ability to meet its payment obligations. OPG will continue to monitor any developments to the Fair Hydro Act and related regulations.

As at September 30, 2018, OPG's unaudited interim consolidated balance sheets included approximately $2 million of unbilled cost recovery revenue from the IESO (December 31, 2017 – $7 million), primarily for OPG's general fee for 2018 as the Financial Services Manager under the Fair Hydro Act relating to management fees, incurred third-party costs, and certain direct labour costs.

INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal control over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

(millions of dollars – except where noted)	**September 30 2018**	**June 30 2018**	**March 31 2018**	**December 31 2017**
Revenue	**1,373**	1,282	1,407	1,619
Net income	**283**	126	539	366
Less: Net income attributable to non-controlling interest	**4**	5	4	4
Net income attributable to the Shareholder	**279**	121	535	362
Earnings per share, attributable to the Shareholder *(dollars)*	**$1.02**	$0.44	$1.99	$1.41

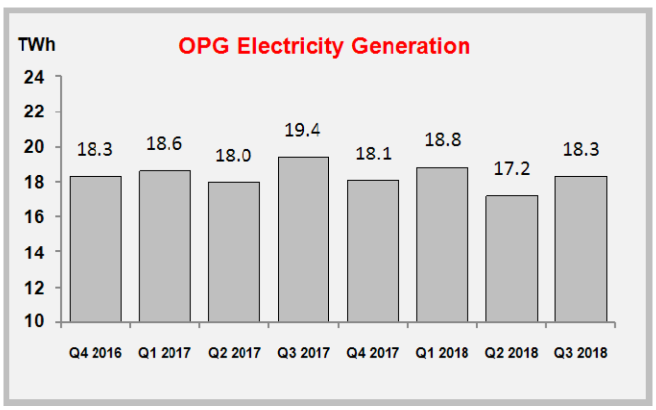
(millions of dollars – except where noted)	**September 30 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	1,217	1,146	1,176	1,388
Net income (loss)	140	307	68	(8)
Less: Net income attribute to the non-controlling interest	9	4	4	5
Net income (loss) attributable to the Shareholder	131	303	64	(13)
Earnings (loss) per share, attributable to the Shareholder *(dollars)*	$0.51	$1.18	$0.25	($0.05)

Trends

OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by the OEB-authorized regulatory accounts.

The outage cycle at each of OPG's nuclear generating stations determines the number and frequency of planned outages in a particular year. The outage cycle is designed to ensure the continued safe and reliable long-term operations of the plant and its compliance with CNSC regulatory requirements. The frequency of planned outages under the outage cycle may result in year-over-year variability in OPG's operating results, including the impact on revenue and OM&A expenses. In addition, the timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year. The Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is continuing, has reduced electricity generation starting in the fourth quarter of 2016.

OPG's financial results are also affected by earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of earnings on the Nuclear Segregated Funds is mitigated by their funded status, as discussed in the 2017 annual M&DA in the section, *Risk Management* under the heading, *Risks to Maintaining Financial Strength – Nuclear Liabilities and Nuclear Segregated Funds*.



SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP, and therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted)	**Twelve Months Ended September 30 2018**	**Twelve Months Ended December 31 2017**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**1,297**	860
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**12,053**	11,351
ROE Excluding AOCI *(percent)*	**10.8**	7.6

(2) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project and business development costs, the impact of regulatory accounts, the Fair Hydro Trust segment, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted)	**2018**	**2017**	**2018**	**2017**
Enterprise TGC				
Total OM&A expenses	**638**	635	**2,103**	2,054
Total fuel expense	**175**	185	**496**	518
Total capital expenditures	**527**	476	**1,282**	1,335
Less: Darlington Refurbishment capital and OM&A costs	**(290)**	(328)	**(807)**	(943)
Less: Other generation development project and business development capital and OM&A costs	**(59)**	(17)	**(104)**	(53)
Add (less): OM&A and fuel expenses deferred in (refundable through) regulatory variance and deferral accounts	**10**	4	**38**	(19)
Less: Nuclear fuel expense for non OPG-operated stations	**(16)**	(13)	**(48)**	(42)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**8**	13	**29**	47
Less: OM&A expenses ancillary to electricity generation business	**(5)**	(4)	**(12)**	(13)
Less: OM&A expenses related to Fair Hydro Trust	**(1)**	-	**(1)**	-
Other adjustments	**(1)**	(3)	**(2)**	(7)
	986	948	**2,974**	2,877
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**18.3**	19.4	**54.3**	56.0
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.1**	0.9	**1.8**	4.2
	18.4	20.3	**56.1**	60.2
Enterprise TGC per MWh *($/MWh)* [1]	**53.64**	46.65	**53.02**	47.77

[1] Amounts may not calculate due to rounding.

(3) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted)	**2018**	**2017**	**2018**	**2017**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**507**	511	**1,731**	1,693
Regulated – Nuclear Generation fuel expense	**73**	81	**208**	217
Regulated – Nuclear Generation capital expenditures	**409**	409	**1,041**	1,150
Less: Darlington Refurbishment capital and OM&A costs	**(290)**	(328)	**(807)**	(943)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**11**	5	**46**	6
Less: Nuclear fuel expense for non OPG-operated stations	**(16)**	(13)	**(48)**	(42)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(1)**	(1)	**(4)**	(3)
Other adjustments	**(2)**	1	**(4)**	(1)
	691	665	**2,163**	2,077
Nuclear electricity generation (TWh)	**10.6**	11.3	**29.6**	30.6
Nuclear TGC per MWh (*$/MWh*) [1]	**64.72**	58.75	**73.05**	67.87

[1] Amounts may not calculate due to rounding.

(4) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Ranney Falls GS and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2018**	**2017**	**2018**	**2017**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**83**	81	**245**	232
Regulated – Hydroelectric fuel expense	**87**	88	**242**	258
Contracted Generation Portfolio OM&A expenses	**43**	39	**127**	118
Contracted Generation Portfolio fuel expense	**15**	15	**46**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**104**	56	**204**	141
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(53)**	(17)	**(99)**	(52)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(44)**	(39)	**(130)**	(119)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts	**(1)**	(1)	**(8)**	(25)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**8**	13	**29**	47
Other adjustments	**-**	(1)	**-**	-
	242	234	**656**	642
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.0**	7.3	**22.3**	23.5
Contracted Generation Portfolio electricity generation	**0.7**	0.8	**2.4**	1.9
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**-**	0.8	**1.7**	4.1
	7.7	8.9	**26.4**	29.5
Hydroelectric TGC per MWh *($/MWh)* [1]	**31.48**	26.20	**24.87**	21.74

[1] Amounts may not calculate due to rounding.

(5) **Gross margin** is defined as revenue less fuel expense.

For further information, please contact:	Investor Relations	416-592-6700
		webmaster@opg.com
	Media Relations	416-592-4008
		1-877-592-4008

www.opg.com
www.sedar.com

ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2018

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	Three Months Ended September 30 2018	Three Months Ended September 30 2017	Nine Months Ended September 30 2018	Nine Months Ended September 30 2017
Revenue	**1,373**	1,217	**4,062**	3,539
Fuel expense	**175**	185	**496**	518
Gross margin	**1,198**	1,032	**3,566**	3,021
Operations, maintenance and administration	**638**	635	**2,103**	2,054
Depreciation and amortization	**200**	178	**584**	517
Accretion on fixed asset removal and nuclear waste management liabilities	**245**	235	**739**	709
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(216)**	(196)	**(638)**	(579)
Earnings from Fair Hydro Trust *(Note 16)*	**(8)**	-	**(20)**	-
Property taxes	**10**	8	**28**	30
Income from investments subject to significant influence	**(12)**	(11)	**(32)**	(29)
	857	849	**2,764**	2,702
Income before other gains/losses, interest and income taxes	**341**	183	**802**	319
Other losses (gains) *(Note 19)*	**8**	3	**(246)**	(380)
Income before interest and income taxes	**333**	180	**1,048**	699
Net interest expense *(Note 5)*	**19**	21	**56**	56
Income before income taxes	**314**	159	**992**	643
Income tax expense *(Note 8)*	**31**	19	**44**	128
Net income	**283**	140	**948**	515
Net income attributable to the Shareholder	**279**	131	**935**	498
Net income attributable to non-controlling interest	**4**	9	**13**	17
Basic and diluted earnings per share *(dollars) (Note 14)*	**1.02**	0.51	**3.43**	1.94

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2018	2017	Nine Months Ended September 30 2018	2017
Net income	**283**	140	**948**	515
Other comprehensive income, net of income taxes *(Note 9)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**2**	3	**7**	8
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**4**	4	**13**	13
Unrealized loss on equity securities [3]	**-**	(4)	**-**	(6)
Other comprehensive income for the period	**6**	3	**20**	15
Comprehensive income	**289**	143	**968**	530
Comprehensive income attributable to the Shareholder	**285**	134	**955**	513
Comprehensive income attributable to non-controlling interest	**4**	9	**13**	17

[1] Net of income tax expenses of $1 million and nil for the three months ended September 30, 2018 and 2017, respectively. Net of income tax expenses of $3 million and $2 million for the nine months ended September 30, 2018 and 2017, respectively.

[2] Net of income tax expense of $1 million for the three months ended September 30, 2018 and 2017. Net of income tax expenses of $2 million for the nine months ended September 30, 2018 and 2017.

[3] Net of income tax expense of nil for the three months ended September 30, 2018 and 2017. Net of income tax recovery of nil and $1 million for the nine months ended September 30, 2018 and 2017, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2018**	**2017**
Operating activities		
Net income	**948**	515
Adjust for non-cash items:		
Depreciation and amortization	**584**	517
Accretion on fixed asset removal and nuclear waste management liabilities	**739**	709
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(638)**	(579)
Pension and other post-employment benefit costs *(Note 10)*	**297**	339
Deferred income taxes	**(29)**	50
Regulatory assets and regulatory liabilities	**(96)**	(97)
Other gains	**(241)**	(374)
Other	**(27)**	(35)
Expenditures on fixed asset removal and nuclear waste management	**(218)**	(231)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**73**	59
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(243)**	(270)
Distributions received from investments subject to significant influence	**37**	37
Net changes to other long-term assets and long-term liabilities	**102**	107
Net changes to non-cash working capital balances *(Note 17)*	**(125)**	(31)
Cash flow provided by operating activities	**1,163**	716
Investing activities		
Investment in property, plant and equipment and intangible assets	**(1,296)**	(1,292)
Net proceeds from sale of property, plant and equipment	**273**	484
Acquisition of Fair Hydro Trust financing receivables	**(609)**	-
Proceeds from deposit note	**-**	70
Cash flow used in investing activities	**(1,632)**	(738)
Financing activities		
Issuance of Class A shares *(Note 13)*	**268**	-
Net proceeds from issuance of OPG long-term debt *(Note 5)*	**1,047**	800
Repayment of OPG long-term debt	**(377)**	(852)
Net proceeds from issuance of Fair Hydro Trust long-term debt *(Note 5)*	**1,206**	-
Repayment of Fair Hydro Trust revolving warehouse debt	**(900)**	-
Distribution to non-controlling interest	**(13)**	(11)
Contribution from non-controlling interest	**-**	19
Dividend to the Province's Consolidated Revenue Fund *(Note 18)*	**(283)**	-
Issuance of short-term debt	**2,799**	1,458
Repayment of short-term debt	**(2,991)**	(1,298)
Cash flow provided by financing activities	**756**	116
Net increase in cash, cash equivalents and restricted cash	**287**	94
Cash, cash equivalents and restricted cash, beginning of period	**234**	186
Cash, cash equivalents and restricted cash, end of period	**521**	280

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2018**	**December 31 2017**
Assets		
Current assets		
Cash, cash equivalents and restricted cash *(Note 3)*	**521**	234
Equity securities	**148**	188
Receivables from related parties	**435**	369
Nuclear fixed asset removal and nuclear waste management funds	**17**	23
Fuel inventory	**308**	309
Materials and supplies	**106**	103
Regulatory assets *(Note 4)*	**416**	-
Prepaid expenses	**172**	192
Other current assets	**116**	146
	2,239	1,564
Property, plant and equipment	**31,187**	29,950
Less: accumulated depreciation	**9,086**	8,628
	22,101	21,322
Intangible assets	**334**	565
Less: accumulated amortization	**201**	432
	133	133
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**17,270**	16,701
Financing receivables	**1,788**	1,179
Long-term materials and supplies	**345**	355
Regulatory assets *(Note 4)*	**6,977**	7,231
Investments subject to significant influence	**304**	309
Other long-term assets	**52**	28
	26,736	25,803
	51,209	48,822

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2018**	**December 31 2017**
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**1,139**	1,228
Short-term debt *(Note 6)*	**68**	260
Deferred revenue due within one year	**3**	12
Long-term debt due within one year *(Note 5)*	**303**	398
Income taxes payable	**23**	80
Regulatory liabilities *(Note 4)*	**30**	-
	1,566	1,978
Long-term debt *(Note 5)*	**6,992**	5,921
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 7)*	**21,046**	20,421
Pension liabilities	**3,321**	3,423
Other post-employment benefit liabilities	**3,164**	3,092
Long-term accounts payable and accrued charges	**234**	252
Deferred revenue	**402**	351
Deferred income taxes	**968**	879
Regulatory liabilities *(Note 4)*	**672**	594
	29,807	29,012
Equity		
Common shares *(Note 13)*	**5,126**	5,126
Class A shares *(Note 13)*	**787**	519
Retained earnings	**7,032**	6,396
Accumulated other comprehensive loss *(Note 9)*	**(266)**	(295)
Equity attributable to the Shareholder	**12,679**	11,746
Equity attributable to non-controlling interest	**165**	165
Total equity	**12,844**	11,911
	51,209	48,822

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2018**	**2017**
Common shares *(Note 13)*	**5,126**	5,126
Class A shares *(Note 13)*		
Balance at beginning of period	**519**	-
Issuance of Class A shares	**268**	-
Balance at end of period	**787**	-
Retained earnings		
Balance at beginning of period	**6,396**	5,534
Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)*	**(9)**	-
Adjustment to recognize income tax effects of intercompany transfer of assets to opening retained earnings *(Note 2)*	**(7)**	-
	6,380	5,534
Net income attributable to the Shareholder	**935**	498
Dividend to the Province's Consolidated Revenue Fund *(Note 18)*	**(283)**	-
Reclassification of non-controlling interest on change in ownership interest	**-**	2
Balance at end of period	**7,032**	6,034
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(295)**	(295)
Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)*	**9**	-
Reclassification of non-controlling interest on change in ownership interest	**-**	3
	(286)	(292)
Other comprehensive income	**20**	15
Balance at end of period	**(266)**	(277)
Equity attributable to the Shareholder	**12,679**	10,883
Equity attributable to non-controlling interest		
Balance at beginning of period	**165**	143
Equity contribution from non-controlling interest	**-**	21
Reclassification of non-controlling interest on change in ownership interest	**-**	(5)
Distribution to non-controlling interest	**(13)**	(11)
Income attributable to non-controlling interest	**13**	17
Balance at end of period	**165**	165
Total equity	**12,844**	11,048

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and nine months ended September 30, 2018 and 2017

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2018 and 2017 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2017.

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

In April 2018, OPG received an extension to its previous exemptive relief from the OSC. The exemptive relief will now terminate on the earliest of the following:

- January 1, 2024
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate regulated activities.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2017 comparative amounts have been reclassified from financial statements previously presented to conform to the 2018 interim consolidated financial statement presentation.

Seasonal Variations

OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of surplus baseload generation (SBG) conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in Ontario Energy Board (OEB) approved regulated prices and the actual water flows are mitigated by the OEB-authorized regulatory variance and deferral accounts (regulatory accounts).

Use of Management Estimates

The preparation of interim consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and regulatory liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

New Accounting Standards Effective in 2018

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

Effective January 1, 2018, OPG adopted Topic 606, including relevant practical expedients, utilizing the modified retrospective approach to implement the transition. No differences in the timing or amount of revenue recognition were identified as a result of the adoption of the new standard. The adoption of Topic 606 has required OPG to amend its accounting policy with respect to revenue recognition, as described below.

Revenue from Contracts with Customers – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include base regulated prices and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electrical System Operator (IESO). For electricity generated from its regulated nuclear and regulated hydroelectric facilities, OPG receives payment from the IESO on a monthly basis based on regulated prices authorized by the OEB. OPG's performance obligation with respect to regulated generation is to supply electricity generated from its regulated nuclear and regulated hydroelectric facilities to the wholesale electricity market in Ontario. The Company has determined that this performance obligation is satisfied over time; OPG utilizes the output method under Topic 606 to recognize revenue by applying the relevant base regulated price and rate riders as applicable to each unit of electricity generated and metered to the IESO. This methodology reflects the real-time nature of electricity generation and the underlying performance obligation, of which no portion remains unsatisfied at the end of the applicable reporting period. During interim rate periods authorized by the OEB, revenue is recognized on the basis of interim regulated prices set by the OEB. In instances where a subsequent OEB decision results in a difference between final regulated prices retroactively effective for the interim period and the interim regulated prices, OPG records the resulting adjustment to revenue in connection with that period based on the OEB's decision. Any resulting revenue shortfall in connection with the interim rate period is collected prospectively from the IESO in the manner authorized by the OEB. OPG's receivables in connection with electricity generated from its regulated nuclear and regulated hydroelectric facilities are part of the Company's electricity related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received. For further discussion, refer to Note 11.

Regulated prices currently in effect for OPG's regulated nuclear and regulated hydroelectric generation were established by the OEB's December 2017 decision and March 2018 payment amounts order on OPG's 2016 application for new regulated prices for the 2017-2021 period. In the decision, the OEB set an effective date for the new base regulated prices of June 1, 2017. Pursuant to the decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric facilities and under a custom incentive regulation framework for the nuclear facilities. For the hydroelectric facilities, the new base regulated prices are determined using a formula that annually escalates the previously approved base regulated prices, subject to some adjustments, based on an industry-specific weighted inflation factor reflecting indices published annually by the OEB, less a stretch factor adjustment. For the nuclear facilities, the new base regulated prices are determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account authorized by the OEB pursuant to *Ontario Regulation 53/05*, with the objective of making changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The nuclear revenue requirement for each of the years is based on the OEB-allowed level of operating costs including depreciation and amortization expenses and a return on rate base, less a stretch factor adjustment. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The difference between the non-deferred portion of the nuclear revenue requirement, calculated by multiplying the nuclear base regulated price determined under rate smoothing and the OEB-approved forecast of OPG's nuclear electricity production for the year, and the total approved nuclear revenue requirement for that year determines the portion of the revenue requirement deferred for future collection in the Rate Smoothing Deferral Account. See Note 4 for further information on the March 2018 payment amounts order and the Rate Smoothing Deferral Account.

Base regulated prices in effect for the period January 1, 2017 to May 31, 2017 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs (including depreciation and amortization expenses) for the regulated facilities for 2014 and 2015 and a return on rate base.

Revenue from Contracts with Customers – Non-regulated Generation and Other Contract Revenue

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. The IESO is the counterparty to all ESAs and other contractual arrangements that are currently in effect. Most of OPG's operating non-regulated generating assets are subject to an ESA. As permitted by the practical expedient within Topic 606, revenue from the generating stations subject to an ESA is recognized in the amount that OPG has a right to invoice on a monthly basis to the IESO as the Company satisfies its performance obligation in accordance with the terms of the agreement to supply energy and capacity from the applicable facilities to Ontario's wholesale energy market. No portion of OPG's performance obligation remains unsatisfied at the end of any applicable reporting period. OPG estimates revenues for variable or conditional amounts under each ESA using a most likely amount approach on a contract-by-contract basis. Variable consideration under each ESA is included in revenue only to the extent that it is probable that the amount will not be subject to significant reversal when the underlying uncertainty is resolved. OPG's receivables in connection with electricity generated from its non-regulated assets are part of the Company's electricity related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received. For further discussion, refer to Note 11.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and mid-west regions of the US. Under these arrangements, OPG's performance obligation is to either physically supply energy or provide capacity, depending on the contract, to a counterparty in a control area outside of Ontario. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the interim consolidated statements of income.

OPG also derives non-energy revenue under the terms of a lease arrangement and associated, non-lease agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. The associated agreements include revenue from heavy water sales, detritiation services and nuclear waste management services. Revenues under these associated agreements are recognized as services are provided or when products are delivered, therein satisfying OPG's performance obligation.

In addition, non-energy revenue includes isotope sales and other service revenues. Revenues from these activities are recognized as the respective performance obligations are satisfied, in accordance with the terms stipulated in the respective contracts.

Revenue Recognition – Leasing Revenue

The minimum lease payments stemming from OPG's lease arrangement with Bruce Power related to the Bruce nuclear generating stations are recognized in revenue on a straight-line basis over the term of the lease. Similarly, revenue from real estate rentals is recognized over the term of the lease as the Company renders the requisite services outlined in the respective contracts.

<u>Recognition and Measurement of Financial Assets and Financial Liabilities</u>

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities are required to measure equity investments at fair value and recognize any changes in fair value in net income. The update is effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for securities is no longer available. Effective January 1, 2018, any unrealized gains and losses related to equity securities are recognized in net income instead of other comprehensive income (OCI).

As a result of the adoption of the new guidance, the unrealized cumulative after-tax loss of $9 million on AFS securities reported in accumulated other comprehensive income as at December 31, 2017 was reclassified to opening retained earnings as of January 1, 2018. There were no other impacts on OPG's interim consolidated financial statements upon adoption of the new guidance, other than to replace the accounting policy for AFS securities with a new policy for holdings of equity securities as described below.

Equity Securities

Equity securities held by OPG are measured at fair value, with gains and losses due to changes in fair value recognized within other gains and losses in the interim consolidated statements of income. Related transaction costs are expensed as incurred, and dividend income is included in net income in the period in which dividends are declared. Equity securities are initially measured at the transaction price.

<u>Restricted Cash Disclosures</u>

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows* (Topic 230): *Restricted Cash (a consensus of the FASB Emerging Issues Task Force)*, which clarifies how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is effective for OPG's 2018 fiscal year, including interim periods, and is applied retrospectively. The changes in disclosures required under this update are reflected in the interim consolidated statements of cash flows and Note 3.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits* (Topic 715): *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

Effective January 1, 2018, OPG adopted the new provisions of Topic 715. Adoption of these provisions did not impact OPG's interim consolidated financial statements, as OPG capitalized only the service cost component of postretirement benefits costs prior to the adoption of the new guidance. Additionally, OPG previously included the service cost component of postretirement benefit costs with other compensation costs within operations, maintenance and administration expenses in the interim consolidated statements of income, and did not show a subtotal of income from operations prior to the adoption of the new guidance. As such, the new guidance did not affect the presentation of OPG's interim consolidated financial statements or result in changes in OPG's accounting policies.

Intra-entity Transfers of Assets Other than Inventory

In October 2016, the FASB issued ASU 2016-16, *Income Taxes* (Topic 740): *Intra-Entity Transfers of Assets Other than Inventory*, to amend existing guidance with respect to accounting for the income tax effects of intra-entity asset transfers within the consolidated group. Effective January 1, 2018, entities are required to recognize the income tax effects of all intra-entity asset transfers, with the exception of inventory, as soon as the transfer occurs. Previously, entities were required to defer recognition of such income tax effects until the asset was sold to a third party.

The update is effective for OPG beginning January 1, 2018 and is required to be applied on a modified retrospective basis. On adoption of the update, the Company recorded an adjustment reducing opening retained earnings by $7 million to reflect the associated deferred income tax liability resulting from the cumulative effect of OPG's transfer of assets, other than inventory, to the UMH Energy Limited Partnership (UMH) and the Lower Mattagami Energy Limited Partnership (LME) in prior years. Adoption of this update did not otherwise impact the Company's interim consolidated financial statements, other than through an addition to OPG's accounting policy for income taxes as described below.

Income Taxes – Intra-entity Transfers of Non-inventory Assets

The income tax impact of any intra-entity transfers of non-inventory assets is recognized upon the occurrence of the transfer.

Recent Accounting Pronouncements Not Yet Adopted

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under *Leases* (Topic 840). The update includes comprehensive changes to existing guidance, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the guidance related to the new leasing standard, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition as of the beginning of the earliest comparative period presented in the entity's financial statements. Full retrospective application is prohibited. In July 2018, the FASB issued ASU No. 2018-11, *Leases* (Topic 842) – *Targeted Improvements* wherein entities can utilize an additional optional transition method to apply the new lease accounting standard at the effective date of January 1, 2019. The cumulative impact from adopting the new standard would be recognized as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures. The Company intends to apply this transition method in the implementation of Topic 842.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allow an entity to choose not to evaluate under Topic 842 land easements that exist or have expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840. The Company intends to apply this practical expedient in the implementation of Topic 842.

The Company has implemented a comprehensive project governance framework to oversee the transition to the new leasing guidance, comprised of a Steering Committee, Implementation and Stakeholder Committee, Project Management Office, and various working groups in order to evaluate and implement the new standard. The working groups are represented by cross-functional finance and non-finance stakeholders and will support the financial and operational implementation of the standard. Management has performed procedures to determine the completeness of leasing arrangements that the Company has entered into, and has commenced the quantification of the expected impact of adopting the new standard effective January 1, 2019. During the remainder of the year, management will review the remaining identified leasing arrangements to quantify the impact of adopting Topic 842, and will finalize the determination of which practical expedients the Company will elect to apply as part of the implementation of the standard.

Changes to Disclosure Requirements for Defined Benefit Plans

In August 2018, the FASB issued ASU No. 2018-14, *Compensation – Retirement Benefits – Defined Benefit Plans – General* (Subtopic 715-20): *Disclosure Framework – Changes to the Disclosure Requirements for Defined Benefit Plans* as part of its ongoing efforts to improve the effectiveness of disclosures in notes to financial statements for stakeholders. As part of this update, entities are now required to include additional disclosures such as narrative descriptions of the reasons for significant gains and losses related to changes in the benefit obligations for the period. The update also removed guidance that currently requires disclosures on the amounts in accumulated other comprehensive income expected to be recognized as components of net periodic benefit cost over the next fiscal year, and for public entities, the effects of a one percent change in assumed health care cost trend rates on the net periodic benefit costs and benefit obligation for other post-employment benefits. Changes instituted by this update are effective retrospectively for all periods presented for fiscal years ending after December 15, 2020 with early adoption permitted. OPG is in the process of evaluating the impact from this update on the Company's disclosures for its post-employment benefit programs.

Changes to Disclosure Requirements for Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement* (Topic 820): *Disclosure Framework – Changes to Disclosure Requirements for Fair Value Measurement* to continue to improve the effectiveness of disclosures in financial statements for users. Under the new guidance prescribed in this update, entities must disclose additional information regarding Level 3 fair value measurements held at the end of the reporting period. This amendment also clarified existing guidance around measurement uncertainty and investments in entities that calculate net asset value (NAV). This update is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019 with early adoption permitted. Additional disclosures stemming from this update will be applied prospectively. The Company is assessing its current fair value measurements to determine the impact from the changes in this update.

3. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Cash, cash equivalents and restricted cash consist of the following:

As at *(millions of dollars)*	**September 30 2018**	**December 31 2017**
Cash and cash equivalents	**354**	230
Restricted cash	**167**	4
Total cash, cash equivalents and restricted cash	**521**	234

The Fair Hydro Trust's (the Trust) cash on deposit is subject to contractual restrictions of the Trust's Master Trust Indenture. All of the Trust's bank accounts are under the name and exclusive control of its indenture trustee. Amounts on deposit are restricted in purpose and the distribution of use is subject to the order of payment priority outlined in the Trust's Master Trust Indenture. As of September 30, 2018, the restricted cash balance related to the Fair Hydro Trust is $32 million (December 31, 2017 − $4 million).

Proceeds from OPG's green bond issuance are restricted in purpose and are to be used solely to finance eligible projects that offer tangible environmental benefits, as defined in OPG's Green Bond Framework. The proceeds from the first green bond issuance in June 2018 are to be used to finance eligible hydroelectric projects and are held in a segregated account. During the third quarter of 2018, approximately $313 million was released from the segregated account, representing funds invested in eligible hydroelectric projects from the second half of 2016 to the first half of 2018. As of September 30, 2018, the restricted cash balance related to the green bond issuance is $135 million (December 31, 2017 − nil).

4. REGULATORY ASSETS AND REGULATORY LIABILITIES

Through its March 2017 approval of a partial settlement agreement reached by OPG and interveners on a limited set of issues in OPG's May 2016 application for new regulated prices for the 2017-2021 period and its December 2017 decision on the application, the OEB approved OPG's request to recover amounts totalling $305 million related to previously recorded variance and deferral account balances, without adjustments. These approved amounts relate to the December 31, 2015 balances in all of the Company's regulatory accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. In January 2018, OPG submitted a draft payment amounts order to the OEB to reflect the December 2017 decision's findings.

In March 2018, the OEB issued the final payment amounts order on OPG's application for new regulated prices. With respect to the regulatory accounts, the payment amounts order authorized OPG to collect, through rate riders on nuclear and regulated hydroelectric production, the approved amount of $305 million over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent between January 1, 2019 and December 31, 2019, and 35 percent between January 1, 2020 and

December 31, 2020. Any shortfall or over-recovery of the approved balance due to differences between actual and forecast production is to be recorded in the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account authorized by the OEB.

Amortization of regulatory assets and regulatory liabilities for regulatory account balances approved for disposition in the OEB's March 2018 payment amounts order is recorded on a straight-line basis, effective March 1, 2018, based on the portion of the balances authorized to be collected during the applicable period.

The payment amounts order set a rate smoothing approach and resulting nuclear base regulated prices effective June 1, 2017 such that no amounts are to be deferred in the Rate Smoothing Deferral Account for 2017, 2018 and 2021. Pursuant to the payment amounts order, approximately $500 million is to be deferred in the Rate Smoothing Deferral Account over the 2019-2020 period. The approved rate smoothing approach and nuclear base regulated prices represented an adjustment to the proposal in OPG's January 2018 draft payment amounts order, which was the basis for management's best estimate of the impact of the OEB's December 2017 decision recorded in the fourth quarter of 2017. To reflect this adjustment, in the first quarter of 2018, the Company recorded a reduction of $67 million in the Interim Period Shortfall Revenue regulatory asset previously recognized as of December 31, 2017 and a reversal of the $63 million regulatory liability for the Rate Smoothing Deferral Account previously recognized as of December 31, 2017.

For the regulated hydroelectric facilities, the payment amounts order set base regulated prices for the June 1, 2017 to December 31, 2017 period and for the January 1, 2018 to December 31, 2018 period as calculated by OPG in the draft payment amounts order, based on the incentive regulation formula approved in the December 2017 decision and inflation indices published by the OEB. For the 2019-2021 period, the base regulated prices for the regulated hydroelectric facilities will be determined annually using the approved formula and published indices.

The payment amounts order authorized separate rate riders on nuclear and regulated hydroelectric production for the collection of the June 1, 2017 to February 28, 2018 interim period revenue shortfall over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent between January 1, 2019 and December 31, 2019, and 35 percent between January 1, 2020 and December 31, 2020. The Interim Period Revenue Shortfall regulatory asset is reversed as these riders are collected.

The regulatory assets and liabilities recorded as at September 30, 2018 and December 31, 2017 are as follows:

(millions of dollars)	**September 30 2018**	**December 31 2017**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**686**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**731**	614
Hydroelectric Surplus Baseload Generation Variance Account	**423**	360
Bruce Lease Net Revenues Variance Account	**137**	121
Other variance and deferral accounts	**121**	124
	2,098	1,935
Interim Period Revenue Shortfall	**554**	544
Pension and OPEB Regulatory Asset *(Note 10)*	**3,707**	3,855
Deferred Income Taxes	**1,034**	897
Total regulatory assets	**7,393**	7,231
Less: current portion	**416**	-
Non-current regulatory assets	**6,977**	7,231
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Pension & OPEB Cash Payment Variance Account	**188**	140
Hydroelectric Water Conditions Variance Account	**164**	150
Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account	**103**	103
Other variance and deferral accounts	**247**	201
Total regulatory liabilities	**702**	594
Less: current portion	**30**	-
Non-current regulatory liabilities	**672**	594

In May 2018, pursuant to an accounting order application filed by OPG in December 2017, the OEB authorized the establishment of a new Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, effective January 1, 2018, on a final basis. The purpose of the account is to record the revenue requirement impact of the changes to nuclear fixed asset removal and nuclear waste management liabilities and depreciation and amortization expenses resulting from the changes to the accounting end-of-life assumptions for OPG's Pickering nuclear generating station (GS) implemented effective December 31, 2017. As of September 30, 2018, OPG recognized a regulatory liability of $93 million related to the balance in the deferral account.

In August 2018, OPG filed an application with the OEB requesting approval to disposition regulatory account balances as of December 31, 2017, less amounts previously approved for recovery. The application requests recovery of the balances through new rate riders beginning on January 1, 2019. The decision on OPG's application will be made by the OEB following a public hearing process, which commenced in September 2018.

5. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

(millions of dollars)	September 30 2018	December 31 2017
Senior notes payable to the Ontario Electricity Financial Corporation	**3,420**	3,195
Medium Term Notes	**950**	500
UMH Energy Partnership project debt	**179**	181
PSS Generating Station Limited Partnership project debt	**245**	245
Lower Mattagami Energy Limited Partnership project debt	**1,595**	1,595
Fair Hydro Trust senior debt	**912**	601
Other	**19**	19
	7,320	6,336
Less: unamortized bond issuance fees	**(25)**	(17)
Less: amounts due within one year	**(303)**	(398)
Long-term debt	**6,992**	5,921

In the first quarter of 2018, OPG issued a total of $600 million senior notes payable to the Ontario Electricity Financial Corporation maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent. In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048. The effective and coupon interest rates on these bonds are 3.92 percent and 3.84 percent, respectively.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year senior revolving warehouse facility agreement with an expiry date of December 2019. During the third quarter of 2018, there were no borrowings issued under this facility and as at September 30, 2018, there were outstanding senior notes of $12 million. In October 2018, the capacity of the facility was decreased to $12 million as a result of the Province's September 2018 announcement of its intention to make future proposed legislative changes to the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Act) to cancel the Global Adjustment refinancing component of Ontario's Fair Hydro Plan (Fair Hydro Plan), as discussed further in Notes 12 and 16.

In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued to provide a portion of the funding requirement for the Trust's purchase of Investment Interest from the IESO in December 2017.

In March 2018, the Trust purchased an Investment Interest from the IESO in the amount of $460 million. Approximately $235 million was financed by the Trust through the revolving warehouse facility, and the remaining $225 million was financed through the issuance of subordinated debt to OPG. In April 2018, the Trust purchased an Investment Interest from the IESO in the amount of $149 million. Approximately $76 million was financed by the Trust through the revolving warehouse facility, and the remaining $73 million was funded through the issuance of subordinated debt to OPG.

In April 2018, subsequent to the purchase of the Investment Interest, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the balance of the revolving warehouse facility outstanding after the April 2018 Investment Interest acquisition. The outstanding balance of the revolving warehouse facility of $12 million has been reclassified as long-term debt as at September 30, 2018 reflecting the contractual terms of the facility agreement.

During the first quarter of 2018, $275 million of OPG long-term debt and $500 million of Fair Hydro Trust revolving warehouse facility debt were repaid. During the second quarter of 2018, $52 million of OPG long-term debt and $400 million of Fair Hydro Trust revolving warehouse facility debt were repaid. During the third quarter of 2018, $50 million of OPG long-term debt was repaid.

The following table summarizes the net interest expense:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Interest on long-term debt [1]	**75**	74	**215**	215
Interest on short-term debt	**1**	-	**5**	2
Interest income	**(2)**	(4)	**(5)**	(6)
Interest capitalized to property, plant and equipment and intangible assets	**(48)**	(39)	**(139)**	(121)
Interest related to regulatory assets and liabilities [2]	**(7)**	(10)	**(20)**	(34)
Net interest expense	**19**	21	**56**	56

[1] Excludes interest on Fair Hydro Trust senior debt and interest on OPG's debt attributed to funding a portion of OPG's purchase of the Trust's subordinated debt. These interest costs have been included in earnings from Fair Hydro Trust in the interim consolidated statements of income. Refer to Note 16 for further details.

[2] Includes interest to recognize the cost of financing related to variance and deferral accounts, as authorized by the OEB, and interest costs deferred in certain variance and deferral accounts.

6. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2018, OPG renewed and extended the expiry date of both tranches from May 2022 to May 2023. There were no amounts outstanding under the bank credit facility as at September 30, 2018 and December 31, 2017. There was no commercial paper outstanding under OPG's commercial paper program as at September 30, 2018 (December 31, 2017 − $100 million). The commercial paper program is used to provide short-term funding for the Company, at interest rates of approximately two percent and for less than one year in duration.

As at September 30, 2018, LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2023 and a $100 million tranche maturing in August 2019. As at September 30, 2018, there was $68 million of external commercial paper outstanding under LME's commercial paper program (December 31, 2017 − $160 million). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2018, under the $300 million tranche of the LME's credit facility.

As at September 30, 2018, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $464 million of short-term, uncommitted credit facilities, which support the issuance of letters of credit. OPG uses letters of credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2018, a total of $392 million of letters of credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the Portland Energy Centre.

The Company's short-term, uncommitted credit facilities include an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. In October 2018, the expiry date of the agreement was extended from November 30, 2018 to November 30, 2020. As at September 30, 2018, there were letters of credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby letters of credit facilities in support of its operations. As at September 30, 2018, total letters of credit of $15 million had been issued under these facilities.

7. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at September 30, 2018 and December 31, 2017 consist of the following:

As at *(millions of dollars)*	**September 30** **2018**	**December 31** **2017**
Liability for nuclear used fuel management	**12,388**	11,970
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,330**	8,107
Liability for non-nuclear fixed asset removal	**328**	344
Fixed asset removal and nuclear waste management liabilities	**21,046**	20,421

8. INCOME TAXES

OPG follows the liability method of tax accounting for all its business segments and records an offsetting regulatory asset or regulatory liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Income tax expense for the three months ended September 30, 2018 increased due to higher income before taxes, partially offset by a higher amount of deferred income tax expense recorded as a regulatory asset.

Income tax expense for the nine months ended September 30, 2018 was reduced as a result of a refundable tax credit of $86 million arising on payment of the dividend during the first quarter of 2018 (see Note 18) and a higher amount of deferred income tax expense recorded as a regulatory asset, partially offset by the impact of higher income before taxes.

9. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	Nine Months Ended September 30, 2018			
(millions of dollars)	Unrealized Losses on Cash Flow Hedges	Pension and OPEB	Equity Securities	Total
AOCL, beginning of period	**(66)**	**(220)**	**(9)**	**(295)**
Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)*	**-**	**-**	**9**	**9**
	(66)	**(220)**	**-**	**(286)**
Amounts reclassified from AOCL	**13**	**7**	**-**	**20**
Other comprehensive income for the period	**13**	**7**	**-**	**20**
AOCL, end of period	**(53)**	**(213)**	**-**	**(266)**

	Nine Months Ended September 30, 2017			
(millions of dollars)	Unrealized Losses on Cash Flow Hedges	Pension and OPEB	Equity Securities	Total
AOCL, beginning of period	(87)	(207)	(1)	(295)
Unrealized loss on equity securities	-	-	(6)	(6)
Amounts reclassified from AOCL	13	8	-	21
Other comprehensive income (loss) for the period	13	8	(6)	15
Reclassification of non-controlling interest on change in ownership interest	3	-	-	3
AOCL, end of period	(71)	(199)	(7)	(277)

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2018 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	Three Months Ended September 30, 2018	Nine Months Ended September 30, 2018	Statement of Income Line Item
Amortization of losses from cash flow hedges			
Losses	**5**	**15**	Net interest expense
Income tax recovery	**(1)**	**(2)**	Income tax expense
	4	**13**	
Amortization of amounts related to pension and OPEB			
Actuarial losses	**3**	**10**	See (1) below
Income tax recovery	**(1)**	**(3)**	Income tax expense
	2	**7**	
Total reclassifications for the period	**6**	**20**	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 10 for additional details).

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2017 are as follows:

(millions of dollars)	**Amount Reclassified from AOCL** Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	5	15	Net interest expense
Income tax recovery	(1)	(2)	Income tax expense
	4	13	
Amortization of amounts related to pension and OPEB			
Actuarial losses	3	10	See (1) below
Income tax recovery	-	(2)	Income tax expense
	3	8	
Total reclassifications for the period	7	21	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 10 for additional details).

10. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended September 30, 2018 and 2017 are as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
Components of cost recognized for the period						
Current service costs	**83**	68	**2**	2	**19**	17
Interest on projected benefit obligation	**142**	138	**3**	2	**27**	27
Expected return on plan assets, net of expenses	**(205)**	(191)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**49**	45	**2**	2	**2**	-
Cost recognized [2]	**69**	60	**7**	6	**48**	44

[1] The amortization of net actuarial loss is recognized as an increase to OCI. This increase for the three months ended September 30, 2018 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $50 million (three months ended September 30, 2017 – $44 million).

[2] These pension and OPEB costs for the three months ended September 30, 2018 exclude the net reduction of costs of $25 million from the recognition of changes in the regulatory assets and regulatory liabilities for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended September 30, 2017 – net addition of costs of $3 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2018 and 2017 are as follows:

(millions of dollars)	Registered Pension Plans 2018	Registered Pension Plans 2017	Supplementary Pension Plans 2018	Supplementary Pension Plans 2017	Other Post-Employment Benefits 2018	Other Post-Employment Benefits 2017
Components of cost recognized for the period						
Current service costs	**248**	205	**6**	5	**59**	51
Interest on projected benefit obligation	**425**	411	**9**	8	**81**	81
Expected return on plan assets, net of expenses	**(615)**	(574)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**148**	137	**5**	5	**5**	-
Cost recognized [2]	**206**	179	**20**	18	**145**	132

[1] The amortization of net actuarial loss is recognized as an increase to OCI. This increase for the nine months ended September 30, 2018 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $148 million (nine months ended September 30, 2017 – $132 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2018 exclude the net reduction of costs of $74 million from the recognition of changes in the regulatory assets and regulatory liabilities for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2017 − net addition of costs of $10 million).

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2018 with an effective date of January 1, 2018. The annual funding requirements in accordance with the new actuarial valuation are $195 million for 2018, $199 million for 2019 and $203 million for 2020. The next actuarial valuation must have an effective date no later than January 1, 2021.

11. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars (USD). OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. OPG's electricity related accounts receivable from the IESO constituted $422 million as at September 30, 2018 (December 31, 2017 − $354 million). The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at September 30, 2018 was less than $1 million.

The fair value of the outstanding derivatives totalled a net liability of $1 million as at September 30, 2018 (December 31, 2017 – net liability of $20 million).

Existing pre-tax net losses of $18 million deferred in AOCL as at September 30, 2018 are expected to be reclassified to net income within the next 12 months.

12. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the closing bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors. The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

Transfers into, out of, or between fair value hierarchy levels are deemed to occur on the date of the event or change in circumstances that causes the transfer to occur.

The fair value of the investments within the Nuclear Segregated Funds' real assets portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other investments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Pooled funds are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices.

Certain investments within the Nuclear Segregated Funds' real assets portfolio are measured at fair value by their investment managers using NAV. Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

The following is a summary of OPG's financial instruments and their fair value as at September 30, 2018 and December 31, 2017:

(millions of dollars)	Fair Value September 30 2018	Fair Value December 31 2017	Carrying Value [1] September 30 2018	Carrying Value [1] December 31 2017	Balance Sheet Line Item
Nuclear Segregated Funds (includes current portion) [2]	**17,287**	16,724	**17,287**	16,724	Nuclear fixed asset removal and nuclear waste management funds
Financing receivables	**1,826**	1,179	**1,788**	1,179	Financing receivables
Investment in Hydro One shares	**148**	188	**148**	188	Equity securities
Payable related to cash flow hedges	**(34)**	(40)	**(34)**	(40)	Long-term accounts payable and accrued charges
Long-term debt – OPG (includes current portion)	**(6,695)**	(6,234)	**(6,408)**	(5,735)	Long-term debt
Long-term debt – Fair Hydro Trust	**(920)**	(601)	**(912)**	(601)	Long-term debt
Other financial instruments	**30**	(16)	**30**	(16)	Various

[1] The carrying values of other financial instruments included in cash, cash equivalents and restricted cash, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the Ontario Nuclear Funds Agreement when the Nuclear Segregated Funds are in a surplus position.

The fair value of the Fair Hydro Trust long-term senior debt including the warehouse credit facility and OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

In September 2018, the Province announced its intention to make future proposed legislative changes to the Fair Hydro Act to cancel the Global Adjustment refinancing component of the Fair Hydro Plan. The Province also stated that it intends to fund all of the Trust's obligations issued and outstanding as of the date the limited guarantee is invoked. No future debt issuances are expected to be made by the Trust. The limited guarantee was provided by the Province to specified creditors of the Trust and is triggered by certain events, including through changes made to the Fair Hydro Act that would adversely affect the Trust's ability to meet its payment obligations. Consequently, the fair value of the financing receivables related to the Investment Interests acquired from the IESO was updated to reflect the projected cash flows and expected returns on the asset to be collected from the Province. Therefore, the fair value of the financing receivables is based on Level 3 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at September 30, 2018 and December 31, 2017:

	September 30, 2018			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**6,024**	**4,931**	**-**	**10,955**
Investments measured at NAV [1]				**1,513**
				12,468
Due to Province				**(2,601)**
Used Fuel Segregated Fund, net				**9,867**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,559**	**3,630**	**-**	**8,189**
Investments measured at NAV [1]				**1,227**
				9,416
Due to Province				**(1,996)**
Decommissioning Segregated Fund, net				**7,420**
Investment in equity securities	**148**	**-**	**-**	**148**
Other financial assets	**1**	**2**	**39**	**42**
Liabilities				
Other financial liabilities	**(11)**	**(1)**	**-**	**(12)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

(millions of dollars)	Level 1	December 31, 2017 Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	6,090	4,705	-	10,795
Investments measured at NAV [1]				1,292
				12,087
Due to Province				(2,529)
Used Fuel Segregated Fund, net				9,558
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,547	3,487	-	8,034
Investments measured at NAV [1]				1,065
				9,099
Due to Province				(1,933)
Decommissioning Segregated Fund, net				7,166
Investment in equity securities	188	-	-	188
Other financial assets	5	3	6	14
Liabilities				
Other financial liabilities	(28)	(2)	-	(30)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the nine months ended September 30, 2018, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the three months ended September 30, 2018:

(millions of dollars)	Other financial instruments
Opening balance, July 1, 2018	**39**
Unrealized losses included in revenue	**(1)**
Realized losses included in revenue	**(3)**
Purchases	**4**
Closing balance, September 30, 2018	**39**

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the nine months ended September 30, 2018:

(millions of dollars)	Other financial instruments
Opening balance, January 1, 2018	**6**
Unrealized losses included in revenue	**(1)**
Realized losses included in revenue	**(10)**
Purchases	**44**
Closing balance, September 30, 2018	**39**

Investments Measured at Net Asset Value

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at September 30, 2018:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Real Assets				
Infrastructure	**1,549**	**649**	**n/a**	**n/a**
Real Estate	**1,073**	**475**	**n/a**	**n/a**
Agriculture and Timberland	**119**	**69**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**40**	**n/a**	**Daily**	**1-5 days**
Fixed Income	**497**	**n/a**	**Daily**	**1-5 days**
Equity	**878**	**n/a**	**Daily**	**1-5 days**
Total	**4,156**	**1,193**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture and timberland investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments such as energy, transportation and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in partners' capital and/or underlying investments held by subsidiaries of an infrastructure fund. The investments in the respective infrastructure funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds will be liquidated. However, the infrastructure funds have a maturity end period ranging from 2019 to 2025.

Real Estate

This class includes investments in institutional-grade real estate property. The investment objective is to provide a stable level of income with the opportunity for long-term capital appreciation. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The partnership investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this class will be liquidated.

Agriculture and Timberland

This class includes a diversified portfolio of global farmland and timberland investments. The investment objective is to provide a differentiated return source, income yield, and inflation protection. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

13. SHARE CAPITAL

Common Shares

As at September 30, 2018 and December 31, 2017, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

In March 2018 and December 2017, OPG issued 4,627,343 Class A shares at a price of $43.74 per share and 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injections in OPG, generating proceeds of $202 million and $519 million, respectively.

In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million.

As at September 30, 2018, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million (December 31, 2017 − 12,217,616 Class A shares issued and outstanding at a stated value of $519 million).

14. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding for three months ended September 30, 2018 was 274.6 million (three months ended September 30, 2017 – 256.3 million) and for the nine months ended September 30, 2018 was 272.7 million (nine months ended September 30, 2017 – 256.3 million). There were no dilutive securities as at September 30, 2018 and September 30, 2017.

15. COMMITMENTS AND CONTINGENCIES

Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from the Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at September 30, 2018, the total amount of guarantees OPG provided to these entities was $78 million (December 31, 2017 − $82 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at September 30, 2018, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

Contractual and Commercial Commitments

OPG's contractual obligations as at September 30, 2018 are as follows:

(millions of dollars)	**2018** [1]	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Fuel supply agreements	46	125	115	88	67	67	508
Contributions to the OPG registered pension plan [2]	33	199	203	-	-	-	435
OPG long-term debt repayment	21	368	663	413	172	4,771	6,408
Interest on OPG long-term debt	66	267	245	216	202	4,052	5,048
Fair Hydro Trust senior debt repayment	-	12	-	-	-	900	912
Interest on Fair Hydro Trust senior debt	16	31	31	31	31	410	550
Commitments related to Darlington Refurbishment project [3]	375	-	-	-	-	-	375
Commitments related to Nanticoke Solar Project	17	-	-	-	-	-	17
Commitments related to Ranney Falls GS project	8	4	-	-	-	-	12
Operating licences	10	41	41	42	43	135	312
Operating lease obligations	7	26	25	22	22	78	180
Unconditional purchase obligations	14	54	52	4	-	-	124
Accounts payable and accrued charges	879	18	-	-	-	16	913
Other	38	42	4	1	2	63	150
Total	1,530	1,187	1,379	817	539	10,492	15,944

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2018. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2021. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2020 for the OPG registered pension plan are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

16. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended September 30, 2018 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Contracted Generation Portfolio	Fair Hydro Trust	Other	Elimination	Total
Revenue from contracts with customers	888	-	331	142	-	1	-	1,362
Leasing revenue	10	-	-	-	-	5	-	15
Other revenue	-	33	-	-	-	9	(46)	(4)
Total revenue	898	33	331	142	-	15	(46)	1,373
Fuel expense	73	-	87	15	-	-	-	175
Gross margin	825	33	244	127	-	15	(46)	1,198
Operations, maintenance and administration	507	33	83	43	1	17	(46)	638
Depreciation and amortization	131	-	39	21	-	9	-	200
Accretion on fixed asset removal and nuclear waste management liabilities	-	242	-	2	-	1	-	245
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(216)	-	-	-	-	-	(216)
Earnings from Fair Hydro Trust	-	-	-	-	(8)	-	-	(8)
Income from investments subject to significant influence	-	-	-	(12)	-	-	-	(12)
Property taxes	8	-	1	1	-	-	-	10
Other losses	-	-	-	2	-	6	-	8
Income (Loss) before interest and income taxes	179	(26)	121	70	7	(18)	-	333
Net interest expense								19
Income before income taxes								314
Income tax expense								31
Net income								283

Segment Income (Loss) for the Three Months Ended September 30, 2017 *(millions of dollars)*	Regulated		Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Contracted Generation Portfolio	Other	Elimination	Total
Revenue from contracts with customers	730	-	327	141	-	-	1,198
Leasing revenue	9	-	-	-	4	-	13
Other revenue	-	33	-	-	15	(42)	6
Total revenue	739	33	327	141	19	(42)	1,217
Fuel expense	81	-	88	15	1	-	185
Gross margin	658	33	239	126	18	(42)	1,032
Operations, maintenance and administration	511	35	81	39	11	(42)	635
Depreciation and amortization	116	-	34	20	8	-	178
Accretion on fixed asset removal and nuclear waste management liabilities	-	230	-	3	2	-	235
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(196)	-	-	-	-	(196)
Income from investments subject to significant influence	-	-	-	(11)	-	-	(11)
Property taxes	7	-	1	-	-	-	8
Other losses (gains)	4	-	1	-	(2)	-	3
Income (Loss) before interest and income taxes	20	(36)	122	75	(1)	-	180
Net interest expense							21
Income before income taxes							159
Income tax expense							19
Net income							140

Segment Income (Loss) for the Nine Months Ended September 30, 2018 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Contracted Generation Portfolio	Fair Hydro Trust	Other	Elimination	Total
Revenue from contracts with customers	2,484	-	1,077	440	-	11	-	4,012
Leasing revenue	28	-	-	-	-	13	-	41
Other revenue	-	98	-	-	-	42	(131)	9
Total revenue	2,512	98	1,077	440	-	66	(131)	4,062
Fuel expense	208	-	242	46	-	-	-	496
Gross margin	2,304	98	835	394	-	66	(131)	3,566
Operations, maintenance and administration	1,731	98	245	127	1	32	(131)	2,103
Depreciation and amortization	382	-	115	60	-	27	-	584
Accretion on fixed asset removal and nuclear waste management liabilities	-	729	-	6	-	4	-	739
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(638)	-	-	-	-	-	(638)
Earnings from Fair Hydro Trust	-	-	-	-	(20)	-	-	(20)
Income from investments subject to significant influence	-	-	-	(32)	-	-	-	(32)
Property taxes	21	-	1	5	-	1	-	28
Other losses (gains)	-	-	4	2	-	(252)	-	(246)
Income (Loss) before interest and income taxes	170	(91)	470	226	19	254	-	1,048
Net interest expense								56
Income before income taxes								992
Income tax expense								44
Net income								948

Segment (Loss) Income for the Nine Months Ended September 30, 2017 *(millions of dollars)*	**Regulated**			**Unregulated**			
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Contracted Generation Portfolio**	**Other**	**Elimination**	**Total**
Revenue from contracts with customers	1,973	-	1,069	431	2	-	3,475
Leasing revenue	27	-	-	-	24	-	51
Other revenue	-	90	-	-	44	(121)	13
Total revenue	2,000	90	1,069	431	70	(121)	3,539
Fuel expense	217	-	258	42	1	-	518
Gross margin	1,783	90	811	389	69	(121)	3,021
Operations, maintenance and administration	1,693	96	232	118	36	(121)	2,054
Depreciation and amortization	333	-	103	59	22	-	517
Accretion on fixed asset removal and nuclear waste management liabilities	-	696	-	7	6	-	709
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(579)	-	-	-	-	(579)
Income from investments subject to significant influence	-	-	-	(29)	-	-	(29)
Property taxes	20	-	1	5	4	-	30
Other losses (gains)	4	-	1	-	(385)	-	(380)
(Loss) income before interest and income taxes	(267)	(123)	474	229	386	-	699
Net interest expense							56
Income before income taxes							643
Income tax expense							128
Net income							515

The earnings from Fair Hydro Trust are comprised of the following for the three and nine months ended September 30:

(millions of dollars)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2018	**2017**	**2018**	**2017**
Revenue	**(1)**	-	**(2)**	-
Operating expenses	**1**	-	**2**	-
Interest income	**(18)**	-	**(45)**	-
Interest expense	**10**	-	**25**	-
Earnings from Fair Hydro Trust	**(8)**	-	**(20)**	-

In December 2017, the Fair Hydro Trust was established as a separate entity to be the financing entity contemplated by the Fair Hydro Act. The majority unitholder and beneficiary of the Trust is a wholly owned subsidiary of OPG, and the Trust's financial position and results are consolidated into OPG's financial results. As a legal matter, the assets and liabilities of the Trust do not form part of the assets and liabilities of OPG, and vice versa, pursuant to section 53.1(1.4) of the *Electricity Act, 1998* (Ontario).

In September 2018, the Province announced its intention to make future proposed legislative changes to the Fair Hydro Act to cancel the Global Adjustment refinancing component of the Fair Hydro Plan. The Province also stated that it intends to fund all of the Trust's obligations issued and outstanding as of the date the limited guarantee is invoked. No future debt issuances are expected to be made by the Trust. The limited guarantee was provided by the Province to specified creditors of the Trust and is triggered by certain events, including through changes made to the Fair Hydro Act that would adversely affect the Trust's ability to meet its payment obligations. OPG will continue to monitor any developments to the Fair Hydro Act and related regulations.

17. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Nine Months Ended September 30	
(millions of dollars)	**2018**	**2017**
Receivables from related parties	**(66)**	72
Fuel inventory	**1**	20
Materials and supplies	**11**	17
Prepaid expenses	**(4)**	(18)
Other current assets [1]	**25**	6
Income taxes recoverable	**(57)**	(92)
Accounts payable and accrued charges	**(35)**	(36)
	(125)	(31)

[1] Represents other accounts receivable.

18. PAYMENT OF DIVIDEND TO SHAREHOLDER

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

19. SALE OF LAKEVIEW SITE

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million, which is net of income tax effects of $68 million, recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG will be required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund.

20. ACQUISITION OF EAGLE CREEK RENEWABLE ENERGY LLC

On August 8, 2018, OPG entered into a purchase and sale agreement with Power Energy Eagle Creek, LLC and Hudson Clean Energy Partners LP to acquire 100 percent of the equity in Eagle Creek Renewable Energy LLC (Eagle Creek) for USD $298 million, subject to customary working capital and other adjustments. Eagle Creek is a hydropower platform, with 226 megawatt of capacity spread across 76 hydroelectric facilities and two solar facilities throughout the US, and represents an opportunity to expand OPG's renewable generation portfolio to new geographies, with additional carbon-free generation aligning to OPG's strategic imperatives. The majority of facilities within Eagle Creek's fleet have operated as merchant based plants in the New England, Michigan and New York market areas. In the third quarter of 2018, OPG received Hart-Scott-Rodino Act antitrust regulatory approval, and is currently awaiting final federal regulatory approvals from the Committee on Foreign Investment in the United States (CFIUS) prior to the closing of the acquisition. The transaction is expected to close by the end of 2018.