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November 8, 2021

OPG REPORTS 2021 THIRD QUARTER FINANCIAL RESULTS

Darlington Unit 3 Refurbishment transitions to the Reassembly segment; OPG launches Reconciliation Action Plan and advances ED&I goals

Toronto – Ontario Power Generation Inc. (OPG or Company) today reported its financial and operating results for the third quarter of 2021, with net income attributable to the Shareholder of $426 million, compared to $386 million for the same period last year.

Third quarter highlights include:

Darlington Refurbishment

“Refurbishment of Darlington’s Unit 3 continues to progress well, and the team is moving into reassembling the Unit,” said Ken Hartwick, OPG President and CEO. “Leveraging lessons learned from the first Unit refurbishment at Darlington, disassembly of Unit 3 was completed safely and with quality. This is thanks to the outstanding planning, collaboration and execution by the team while safely working under both COVID-19 restrictions and hot summer conditions.”

Launching the first-ever OPG Reconciliation Action Plan and recognition by the Canadian Council for Aboriginal Business

Building on the Company’s long-standing commitment to Indigenous communities, OPG recently announced its Reconciliation Action Plan. The action plan will serve as the Company’s roadmap for how it intends to continue to engage and work with Indigenous communities, businesses and organizations to advance reconciliation. OPG has set a goal of growing the Company’s existing economic impact for Indigenous communities and businesses to $1 billion over the next 10 years through ongoing operations, projects and initiatives. During the quarter, OPG was also honoured with the Gold designation through the Canadian Council for Aboriginal Business’ Progressive Aboriginal Relations (PAR) program.

“PAR Gold companies demonstrate sustained leadership in Indigenous relations and commitment to working with Aboriginal businesses and communities through innovative programs and engagement,” said Hartwick. “Our Reconciliation Action Plan is the next step on our journey, which outlines our overall goals and supporting actions to enhance Indigenous procurement, increase Indigenous representation across all levels of our company, strengthen environmental stewardship, and improve awareness and understanding of Indigenous culture, history, and perspectives within OPG.”

OPG's leadership commitment to equity, diversity and inclusion (ED&I)

"We recently welcomed three new members to OPG's Board of Directors," said Hartwick. "Each of these members brings to the Board extraordinary talent and experience and adds to the Board's expertise in OPG's most critical operational and strategic areas. We are well served by having a Board that is diverse in so many areas."

With the new additions, women comprise 60 per cent of OPG's independent board members, making OPG's Board of Directors one of the most gender diverse boards in the industry.

Net Income attributable to the Shareholder

The increase in net income attributable to the Shareholder for the third quarter of 2021, compared to the same period in 2020, was partly due to revenue from higher electricity generation from the Regulated – Nuclear Generation business segment.

On August 6, 2021, the Ontario Energy Board (OEB) approved a settlement agreement on most of the issues in OPG's application for new regulated prices for nuclear electricity generation for the 2022-2026 period. As part of the settlement agreement, OPG will be returning $47 million to customers due to the net favourable impact on electricity revenue net of operations, maintenance and administration (OM&A) expenses arising from the Company's pandemic response over 2020 and 2021. The recognition of this transaction took place during the quarter and partially offset the increase in net income. The OEB's decision on the unsettled issues in the application is expected in the fourth quarter of 2021 and the resulting new nuclear regulated prices will be effective January 1, 2022. The base regulated price for OPG's hydroelectric electricity generation for the 2022-2026 period will be equal to the current approved 2021 regulated price.

Net income attributable to the Shareholder for the third quarter of 2021 also increased due to lower income tax expense primarily due to a higher amount of income tax expense deferred as regulatory assets compared to the same quarter in 2020.

Generating and Operating Performance

Electricity generated during the third quarter of 2021 was 21.0 terawatt hours (TWh), compared to 21.3 TWh for the same period in 2020. Electricity generated during the nine months ended September 30, 2021 decreased to 59.3 TWh from 62.9 TWh for the same period in 2020.

Regulated – Nuclear Generation Segment

Electricity generation from the regulated nuclear stations increased by 0.3 TWh during the third quarter, primarily due to fewer cyclical maintenance planned outage days at the Pickering nuclear generating station (Pickering GS), partially offset by Unit 3 of the Darlington nuclear generating station (Darlington GS) undergoing refurbishment throughout 2021. During the third quarter of 2020, all Darlington GS units were generating electricity following the return to service of Unit 2 from refurbishment on June 4, 2020 and prior to Unit 3 being taken offline on July 30, 2020 for a planned outage immediately preceding the start of refurbishment activities.

Electricity generation from the regulated nuclear stations decreased by 2.9 TWh for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to Unit 3 of the Darlington GS undergoing refurbishment throughout 2021. The decrease was also driven by the deferral of a planned cyclical maintenance outage for Unit 1 of the Darlington GS from 2020 to 2021 as a result of changes made to the Darlington Refurbishment schedule in response to the COVID-19 pandemic in 2020.

At the Darlington GS, the unit capability factor of 99.7 per cent for the three months ended September 30, 2021 increased from 88.3 per cent for the same quarter in 2020, primarily due to fewer planned outage days. For the nine months ended September 30, 2021, the station's unit capability factor decreased to 86.5 per cent, compared to 93.4 per cent for the same period in 2020. The decrease was primarily due to a higher number of planned and unplanned outage days, including the deferral of the Unit 1 planned cyclical maintenance outage from 2020 to 2021.

At the Pickering GS, the unit capability factor increased to 94.1 per cent and 83.5 per cent for the three and nine month periods ended September 30, 2021, respectively, compared to 78.4 per cent and 79.4 per cent for the same periods in 2020, primarily due to fewer planned outage days.

Regulated – Hydroelectric Generation Segment

Electricity generation from the regulated hydroelectric stations decreased by 0.4 TWh and 1.6 TWh during the three and nine month periods ended September 30, 2021, respectively, compared to the same periods in 2020. The decreases in both periods were primarily due to lower water flows across most of Ontario.

Availability at the regulated hydroelectric stations decreased to 81.9 per cent for the three months ended September 30, 2021, compared to 82.6 per cent in 2020. The decrease was primarily due to higher planned outage days from the deferral of certain planned maintenance and project activities from 2020 in response to the onset of the COVID-19 pandemic, partially offset by fewer unplanned outage days across the regulated hydroelectric fleet. Availability for the nine months ended September 30, 2021 was comparable to the same period in 2020.

Contracted Hydroelectric and Other Generation Segment

Electricity generation from the Contracted Hydroelectric and Other Generation business segment decreased by 0.2 TWh during the three and nine month periods ended September 30, 2021, compared to the same periods in 2020, primarily due to lower water flows across the hydroelectric facilities in the United States.

Availability of the Ontario-based hydroelectric stations in the segment increased to 83.1 per cent and 87.5 per cent for the three and nine month periods ended September 30, 2021, respectively, compared to 82.1 per cent and 85.1 per cent for the same periods in 2020. The increases in both periods were primarily due to fewer unplanned outage days at the Lower Mattagami generating stations. For the three months ended September 30, 2021, the increase was partially offset by an increase in planned outage days from the deferral of certain planned maintenance activities from 2020 in response to the COVID-19 pandemic.

Contracted Gas Generation Segment

Electricity generation from the combined cycle gas turbine (combined cycle) plants for the three months ended September 30, 2021 was comparable to the same quarter in 2020. During the nine months ended September 30, 2021, electricity generation from the segment increased by 1.1 TWh, primarily from the portfolio of combined cycle plants acquired in April 2020.

Thermal Availability of the generating stations in the segment decreased to 93.2 per cent during the three and nine month periods ended September 30, 2021, compared to 94.4 per cent for the same periods in 2020, primarily due to the impact of planned outages.

Total Generating Cost

The Enterprise Total Generating Cost (TGC) per megawatt hour (MWh) for the third quarter of 2021 was $53.62, compared to $50.36 for the same quarter in 2020. The increase was primarily due to higher capital expenditures in the Regulated – Hydroelectric Generation business segment, as planned, and lower overall electricity generation.

The Enterprise TGC per MWh was $55.75 for the nine months ended September 30, 2021, compared to $46.60 for the same period in 2020. The increase was primarily due to lower overall electricity generation, and higher OM&A expenses, excluding amounts recorded as recoverable from customers in regulatory accounts authorized by the OEB, from the Regulated – Nuclear Generation business segment. The increase in OM&A expenses, excluding the impact of regulatory accounts, was largely due to the deferral of a planned cyclical maintenance outage for Unit 1 of the Darlington GS from 2020 to 2021.

Generation Development

OPG is undertaking a number of generation development and other major projects in support of Ontario's electricity system. The Company continues to execute on these projects while maintaining enhanced safety measures in response to the COVID-19 pandemic.

Significant developments during the third quarter of 2021 included the following:

Darlington Refurbishment

The Darlington Refurbishment project will extend the operating life of the four-unit Darlington GS by at least 30 years.

The Unit 3 refurbishment is progressing on schedule. In October 2021, the project concluded the second major segment of the Unit 3 refurbishment, the Disassembly segment, with the completion of the removal of fuel channel assemblies. The Unit 3 refurbishment has now transitioned to the third major segment, Reassembly, which includes the installation and reassembly of reactor components. Additionally, during the third quarter of 2021, the upper and middle feeder installation series has commenced. Once refurbished, Unit 3 is scheduled to be returned to service in the first quarter of 2024.

Planning and pre-requisite activities for the refurbishment of the subsequent units, Unit 1 and Unit 4, are progressing as planned.

OPG continues to assess and seek ways to manage the impact of the COVID-19 pandemic on the total cost of the project, which is otherwise continuing to track to the $12.8 billion budget.

Sir Adam Beck I Hydroelectric GS Units G1 and G2 Replacement

OPG is continuing to execute on the replacement of two previously decommissioned generating units at the ten-unit Sir Adam Beck I GS in Niagara Falls, Ontario, which will add approximately 125 megawatts (MW) of incremental peaking generation capacity and provide decades of cost effective, clean power from one of the Company's flagship hydroelectric stations. During the third quarter of 2021, the project commenced the G2 unit turbine and generator installation. In addition, the installation and machining of new turbine scroll cases for the G1 unit was completed and the project commenced the installation of the G1 unit turbine.

The project is expected to be placed in service in 2022 and is tracking on budget of $128 million. The Sir Adam Beck I GS is reported in the Regulated – Hydroelectric Generation business segment.

Redevelopment of Calabogie Hydroelectric GS

OPG is redeveloping the Calabogie GS, which was nearing the end of its operational life when it was extensively damaged by a storm in 2018. The new facility will replace the original powerhouse, doubling the station's capacity to approximately 11 MW. During the third quarter of 2021, the project completed construction of the downstream cofferdam, as planned. The construction of the upstream cofferdam is expected to be completed in the fourth quarter of 2021. The project also continues construction on the new powerhouse.

The project is expected to be placed in service in 2022 and is tracking toward a total cost of $145 million. The Calabogie GS is located along the Madawaska River in eastern Ontario and is reported in the Regulated – Hydroelectric Generation business segment.

Lower Mattagami Projects

Little Long Dam Safety Project

OPG continues to execute on a project to improve dam safety along the Lower Mattagami River in northeastern Ontario. The project will increase the discharge capacity and make other improvements at the Little Long Main Dam, helping the Company to comply with updated provincial dam safety requirements. During the third quarter of 2021, rock excavation activities below the Adam Creek spillway structure on the Little Long Reservoir and the concrete placement of the new bays adjacent to the sluicegates continued. The project also commenced the replacement of existing gates and major concrete placement on two new gates.

The project is expected to be placed in service in 2023 and is tracking on budget of $650 million. The Little Long Dam supports OPG’s contracted hydroelectric generating stations in the Contracted Hydroelectric and Other Generation business segment.

Smoky Falls Dam Safety Project

OPG has initiated a project to improve dam safety at the Smoky Falls GS located along the Lower Mattagami River. The project will rehabilitate the 100-year-old spillway and sluiceway structures in compliance with provincial dam safety requirements. In September 2021, the project entered the execution phase, having completed the front-end engineering and design phase. OPG is progressing the procurement of critical services and advanced detailed engineering, design and permitting activities, as well as site preparation and mobilization.

The project is expected to be placed in service in 2025 and has a budget of $390 million. The Smoky Falls GS is one of OPG’s hydroelectric generating stations on the Lower Mattagami River, which is reported in the Contracted Hydroelectric and Other Generation business segment.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2021**	**2020**	**2021**	**2020**
Revenue	**1,712**	1,889	**5,207**	5,458
Fuel expense	**241**	225	**628**	577
Operations, maintenance and administration expenses	**555**	716	**2,067**	2,108
Depreciation and amortization expenses	**277**	337	**832**	985
Accretion on fixed asset removal and nuclear waste management liabilities	**274**	263	**818**	791
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(243)**	(234)	**(722)**	(693)
Other net expenses (gains)	**47**	5	**(50)**	10
Earnings before interest and income taxes	**561**	577	**1,634**	1,680
Net interest expense	**53**	61	**167**	190
Income tax expense	**78**	126	**220**	325
Net income	**430**	390	**1,247**	1,165
Net income attributable to the Shareholder	**426**	386	**1,234**	1,153
Net income attributable to non-controlling interest [1]	**4**	4	**13**	12
Earnings (loss) before interest and income taxes				
Electricity generating business segments	**619**	601	**1,625**	1,749
Regulated – Nuclear Waste Management	**(28)**	(25)	**(87)**	(88)
Other	**(30)**	1	**96**	19
Earnings before interest and income taxes	**561**	577	**1,634**	1,680
Cash flow provided by operating activities	**889**	1,007	**1,965**	2,547
Capital expenditures [2]	**556**	410	**1,462**	1,244
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.7**	11.4	**31.2**	34.1
Regulated – Hydroelectric Generation	**6.9**	7.3	**21.4**	23.0
Contracted Hydroelectric and Other Generation [3]	**0.9**	1.1	**3.6**	3.8
Contracted Gas Generation	**1.5**	1.5	**3.1**	2.0
Total OPG electricity generation	**21.0**	21.3	**59.3**	62.9
Nuclear unit capability factor (per cent) [4]				
Darlington Nuclear GS	**99.7**	88.3	**86.5**	93.4
Pickering Nuclear GS	**94.1**	78.4	**83.5**	79.4
Availability (per cent)				
Regulated – Hydroelectric Generation	**81.9**	82.6	**88.4**	88.4
Contracted Hydroelectric and Other Generation – hydroelectric stations [5]	**83.1**	82.1	**87.5**	85.1
Contracted Gas Generation [6]	**93.2**	94.4	**93.2**	94.4
Equivalent forced outage rate				
Contracted Hydroelectric and Other Generation – thermal stations	**0.8**	9.2	**1.6**	6.0
Enterprise Total Generating Cost (TGC) per MWh ($/MWh) [7]	**53.62**	50.36	**55.75**	46.60

1 Relates to the following: the 25 per cent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership; the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership; the 15 per cent and 5 per cent interests of corporations wholly owned by Six Nations of Grand River Development Corporation and the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP; and non-controlling interests in certain electricity generating facilities in the United States.
2 Includes net changes in accruals; excludes the acquisition of a portfolio of combined cycle plants on April 29, 2020.
3 Includes OPG's proportionate share of electricity generation from co-owned and minority-held facilities.
4 Excludes nuclear unit(s) during the period in which they are undergoing refurbishment.
5 Reflects the availability of contracted hydroelectric generating stations in Ontario. US hydroelectric generating operations are not reflected in these results.
6 Reflects the availability of combined cycle plants, calculated on a three-year rolling average basis.
7 Enterprise TGC per MWh is a non-GAAP financial measure and it does 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, in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

About OPG

As a global climate change leader and the largest, most diverse electricity generator in the province of Ontario, OPG and its family of companies are helping lead the charge to a post-carbon economy.

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, 2021, 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:

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2021 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 month periods ended September 30, 2021. 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, Annual Information Form, and MD&A as at and for the year ended December 31, 2020.

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). The current exemption 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, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP* in OPG's 2020 annual MD&A. This MD&A is dated November 8, 2021.

Additional information about OPG, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com and the Company's website at www.opg.com.

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", "budget", "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, *Corporate Strategy, Core Business 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 (GS) performance, availability and operating lives, fuel costs, surplus baseload generation (SBG), fixed asset removal and nuclear waste management and associated funding requirements, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, acquisition transactions and other business expansion opportunities, performance of acquired businesses, defined benefit pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of electricity industries and markets in Ontario and the United States (US), the continued application and renewal of energy supply agreements (ESAs) and other contracts for non-regulated facilities, foreign currency exchange rates, commodity prices, wholesale electricity market prices, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC) and the Federal Energy Regulatory Commission (FERC), health, safety and environmental developments, the COVID-19 pandemic, changes in the Company's workforce, renewal of union collective agreements, business continuity events, the weather, climate change, technological change, financing requirements and liquidity, funding sources, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB, forecasts of earnings, cash flow, earnings before interest, income taxes, depreciation and amortization, gross margin, Total Generating Cost (TGC) per megawatt-hour (MWh), operations, maintenance and administration (OM&A) expenses and project and other expenditures, retention of critical talent, and supplier and third party performance. 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.

Use of Non-GAAP Financial Measures

The Company uses the following non-GAAP financial performance measures in the MD&A:

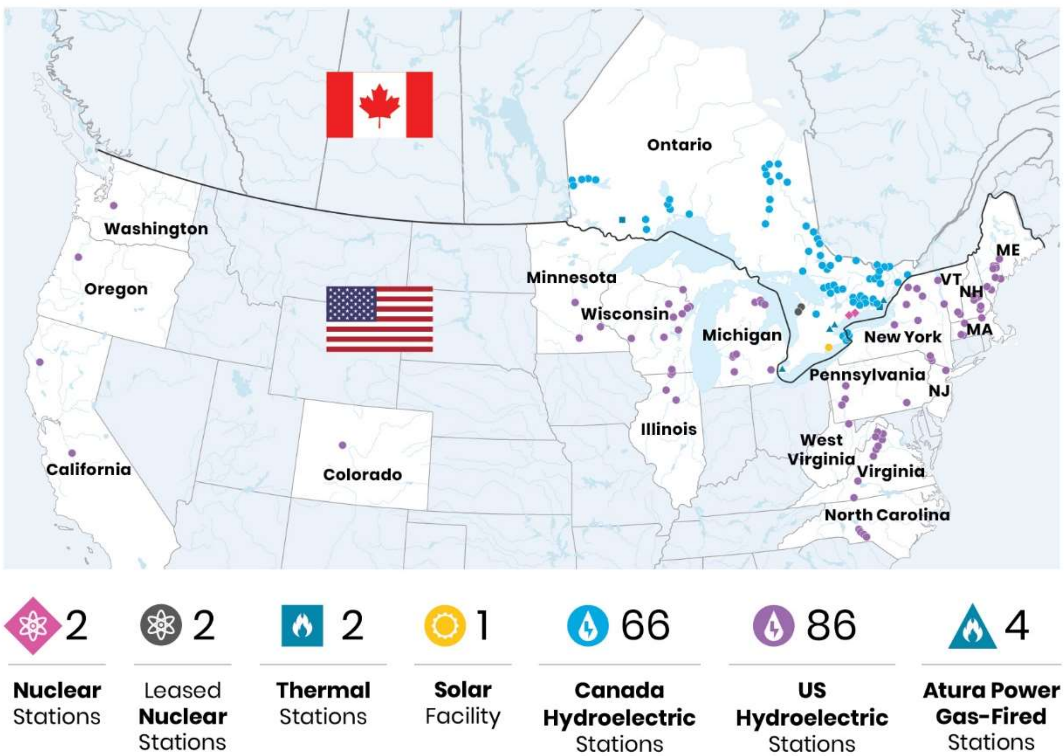
- "Enterprise Total Generating Cost per Megawatt-Hour";
- "Earnings before Interest, Income Taxes, Depreciation and Amortization"; and
- "Gross Margin".

For a detailed description of each of the non-GAAP measures used in this MD&A and a detailed reconciliation to the most directly comparable measure under US GAAP, refer to the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The non-GAAP financial performance measures set out in this MD&A are intended to provide additional information to investors and do not have any standardized meaning under US GAAP, and therefore may not be comparable to other issuers, and should not be considered in isolation or as a substitute for measures of performance prepared under US GAAP.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG's electricity generation portfolio had an in-service generating capacity of 18,910 megawatts (MW) as at September 30, 2021.

As at September 30, 2021, OPG owned and operated two nuclear generating stations, 66 hydroelectric generating stations, two thermal generating stations, one solar facility and four combined cycle gas turbine (combined cycle) plants in Ontario, Canada. The combined cycle plants are natural gas-fired facilities owned and operated through the Company's wholly-owned subsidiary operating as Atura Power. Through its US-based wholly-owned subsidiary, OPG Eagle Creek Holdings LLC, OPG also wholly or jointly owned and operated 86 hydroelectric generating stations and held minority interests in 14 hydroelectric and two solar facilities in the US as at September 30, 2021. In addition, OPG owns two nuclear generating stations in Ontario, the Bruce A GS and the Bruce B GS (Bruce nuclear generating stations), which are leased on a long-term basis to, and operated by, Bruce Power L.P. (Bruce Power).



Income from co-owned and minority-held facilities is accounted for using the equity method of accounting. OPG's proportionate share of in-service generating capacity and electricity generation volume from co-owned and minority held facilities is included in the Company's generation portfolio statistics set out in this MD&A.

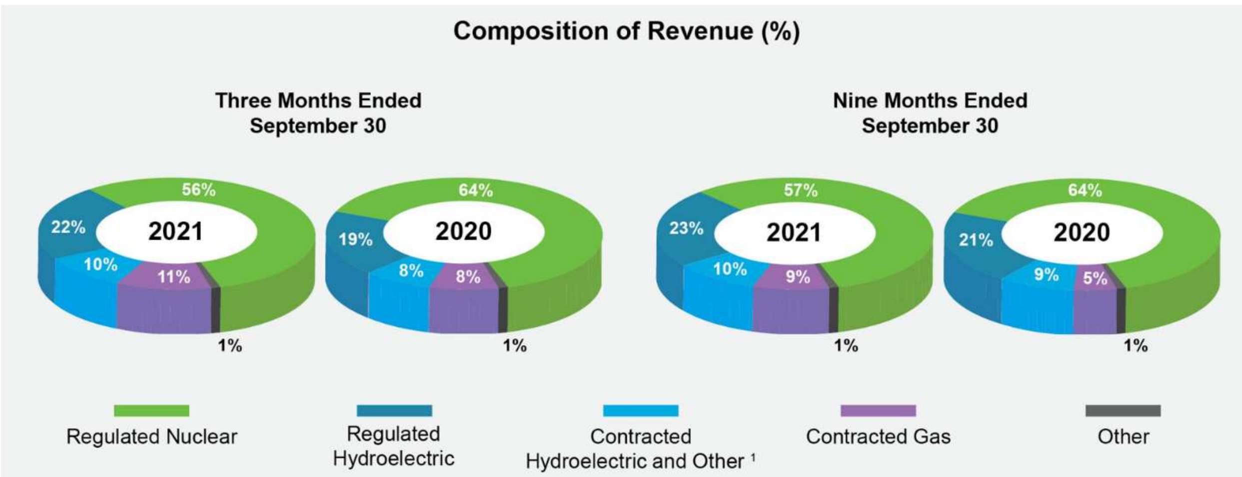
Income from the stations leased to Bruce Power is included in revenue under the Regulated – Nuclear Generation business segment. The leased stations are not included in the Company's electricity generation and other operating statistics set out in this MD&A.

Reporting Structure

The composition of OPG's reportable business segments effective as at September 30, 2021 is as follows:

- Regulated – Nuclear Generation;
- Regulated – Nuclear Waste Management;
- Regulated – Hydroelectric Generation;
- Contracted Hydroelectric and Other Generation; and
- Contracted Gas Generation.

The composition of OPG's revenue by business segment for the three and nine month periods ended September 30, 2021 and 2020 was as follows:



[1] Includes contracted revenue from hydroelectric generating stations operating under ESAs, with expiration dates ranging from 2059 to 2067.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2021 and December 31, 2020 was as follows:

(MW)	As At September 30 2021	As At December 31 2020
Regulated – Nuclear Generation	**5,728**	5,728
Regulated – Hydroelectric Generation	**6,420**	6,420
Contracted Hydroelectric and Other Generation [1]	**4,047**	4,047
Contracted Gas Generation	**2,715**	2,715
Total	**18,910**	18,910

[1] Includes OPG's proportionate share of in-service generating capacity from co-owned and minority shareholdings in electricity generating facilities.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results for the three and nine month periods ended September 30, 2021, compared to the same periods in 2020. A discussion of OPG's performance by business segment can be found 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)	**2021**	**2020**	**2021**	**2020**
Revenue	**1,712**	1,889	**5,207**	5,458
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Net income attributable to non-controlling interest [1]	**4**	4	**13**	12
Electricity generation (TWh) [2]	**21.0**	21.3	**59.3**	62.9
Cash flow				
Cash flow provided by operating activities	**889**	1,007	**1,965**	2,547
Capital expenditures [3]	**556**	410	**1,462**	1,244
Earnings (loss) before interest and income taxes by business segment				
Regulated – Nuclear Generation	**348**	356	**721**	929
Regulated – Hydroelectric Generation	**144**	129	**520**	522
Contracted Hydroelectric and Other Generation	**49**	45	**172**	161
Contracted Gas Generation	**78**	71	**212**	137
Total electricity generating business segments	**619**	601	**1,625**	1,749
Regulated – Nuclear Waste Management	**(28)**	(25)	**(87)**	(88)
Other	**(30)**	1	**96**	19
Earnings before interest and income taxes	**561**	577	**1,634**	1,680
Enterprise TGC per MWh ($/MWh) [4]	**53.62**	50.36	**55.75**	46.60

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2 Includes OPG's proportionate share of electricity generation from co-owned and minority-held facilities.

3 Includes net changes in accruals; excludes the acquisition of a portfolio of combined cycle plants on April 29, 2020.

4 Enterprise TGC per MWh is a non-GAAP financial measure and does not have a standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures.*

Third Quarter

Net income attributable to the Shareholder was $426 million for the third quarter of 2021, representing an increase of $40 million compared to the same quarter in 2020.

Earnings before interest and income taxes (EBIT) were $561 million for the third quarter of 2021, a decrease of $16 million compared to the same quarter in 2020.

Significant factors that decreased EBIT:

- A net regulatory liability of $47 million recorded in the third quarter of 2021 to recognize the OEB's decision approving a proposed settlement on most of the issues in OPG's five-year application for new base regulated prices for production from the Company's nuclear facilities (Settlement Agreement) issued on August 6, 2021. As part of the Settlement Agreement, OPG agreed to credit ratepayers with $47 million related to the difference between the Company's net favourable electricity revenue impact and incremental OM&A expenses arising from the pandemic response over 2020 and 2021;

- A decrease in revenue from the Regulated – Nuclear Generation business segment of $98 million reflecting lower amounts recorded in the Rate Smoothing Deferral Account pursuant to the OEB's March 2018 payment amounts order, partially offset by $56 million from a higher base regulated price for OPG's nuclear electricity generation (nuclear base regulated price) effective January 1, 2021; and

- A loss of $33 million related to changes in the market value of non-core equity holdings in a smart energy storage company that became publicly traded during the second quarter of 2021. The original investment was made as part of OPG's strategy to support clean energy innovation in line with climate goals.

Significant factors that increased EBIT:

- Higher revenue from the Regulated – Nuclear Generation business segment of $32 million due to higher electricity generation of 0.3 terawatt hours (TWh); and

- A decrease in depreciation and amortization expenses of $75 million from the Regulated – Nuclear Generation business segment, excluding amortization expense related to the recovery of OEB-authorized regulatory variance and deferral account (regulatory account) balances, primarily due to depreciation expense recorded as recoverable from customers in regulatory accounts in connection with differences in the current accounting end-of-life assumptions for the Pickering nuclear generating station (Pickering GS) from those assumed in the nuclear base regulated price effective January 1, 2021.

Net interest expense decreased by $8 million in the third quarter of 2021, compared to the same quarter in 2020, primarily due to a higher amount of interest costs capitalized related to the Darlington Refurbishment project expenditures.

Income tax expense decreased by $48 million for the third quarter of 2021, compared to the same period in 2020. The decrease was mainly due to a higher amount of income tax expense deferred as regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $1,234 million for the first nine months of 2021, representing an increase of $81 million compared to the same period in 2020.

Earnings before interest and income taxes were $1,634 million for the first nine months of 2021, a decrease of $46 million compared to the same period in 2020.

Significant factors that decreased EBIT:

- Lower revenue from the Regulated – Nuclear Generation business segment of $237 million due to lower electricity generation of 2.9 TWh and $293 million reflecting lower amounts recorded in the Rate Smoothing Deferral Account, partially offset by $150 million from a higher nuclear base regulated price effective January 1, 2021; and
- A net regulatory liability of $47 million recorded in the third quarter of 2021 to recognize the OEB's decision approving the Settlement Agreement issued on August 6, 2021.

Significant factors that increased EBIT:

- A decrease in depreciation and amortization expenses of $222 million from the Regulated – Nuclear Generation business segment, excluding amortization expense related to the recovery of regulatory account balances, primarily due to depreciation expense recorded as recoverable from customers in regulatory accounts in connection with differences in the current accounting end-of-life assumptions for the Pickering GS from those assumed in the nuclear base regulated price effective January 1, 2021;
- Higher EBIT of $75 million from the Contracted Gas Generation business segment, primarily from the acquisition of a portfolio of combined cycle plants in Ontario on April 29, 2020;
- A gain of $50 million related to changes in the market value of non-core equity holdings in a publicly held smart energy storage company that became publicly traded during the second quarter of 2021; and
- A gain of $30 million on the sale of OPG's former Thunder Bay GS site recognized upon completion of the transaction in April 2021. The former coal-fired generation plant, subsequently converted to operate as a single-unit advanced biomass-fuelled generating station, was located in Thunder Bay, Ontario and ceased operations in 2018.

Net interest expense decreased by $23 million for the nine months ended September 30, 2021, compared to the same period in 2020. The decrease was primarily due to lower amounts of interest recorded as refundable to customers through regulatory accounts and lower interest costs for short-term debt, partially offset by a lower amount of interest costs capitalized related to the Darlington Refurbishment project expenditures.

Income tax expense decreased by $105 million for the nine months ended September 30, 2021, compared to the same period in 2020. The decrease was primarily due to a higher amount of income tax expense deferred as regulatory assets and lower income before taxes.

Trends

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Contracted Gas Generation business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by 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. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by OEB-authorized regulatory accounts.

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Contracted Gas Generation business segment is mitigated by the terms of the applicable ESAs with the Independent Electricity System Operator (IESO) and other long-term contracts for the contracted generating facilities in Ontario.

Electricity generation and the financial results of the Regulated – Nuclear Generation business segment are primarily impacted by outage activities at the nuclear generating stations. The frequency and timing of planned outages under a station's maintenance outage cycle and timing of refurbishment activities may result in period-over-period variability in OPG's financial results. The maintenance outage cycle at each of OPG's nuclear generating stations determines the number of planned outages in a particular year. Outage cycles are designed to ensure continued safe and reliable long-term operations of the stations and their compliance with the CNSC's regulatory requirements.

The Darlington and Pickering nuclear generating stations have been designed to operate at full power as baseload generating facilities and therefore their electricity production does not vary with changes in grid-supplied electricity demand.

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2021 and 2020 was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(TWh)	**2021**	**2020**	**2021**	**2020**
Regulated – Nuclear Generation	**11.7**	11.4	**31.2**	34.1
Regulated – Hydroelectric Generation	**6.9**	7.3	**21.4**	23.0
Contracted Hydroelectric and Other Generation [1]	**0.9**	1.1	**3.6**	3.8
Contracted Gas Generation [1]	**1.5**	1.5	**3.1**	2.0
Total OPG electricity generation	**21.0**	21.3	**59.3**	62.9

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

Total OPG electricity generation decreased by 0.3 TWh and 3.6 TWh for the three and nine month periods ended September 30, 2021, respectively, compared to the same periods in 2020.

Electricity generation from the Regulated – Nuclear Generation business segment increased by 0.3 TWh for the three months ended September 30, 2021, compared to the same period in 2020. The increase was primarily due to fewer cyclical maintenance planned outage days at the Pickering GS, partially offset by lower electricity generation at the Darlington nuclear generating station (Darlington GS). The decrease in electricity generation at the Darlington GS was due to Unit 3 undergoing refurbishment during the third quarter of 2021, compared to all Darlington GS units generating electricity following the return to service of Unit 2 from refurbishment on June 4, 2020 and prior to Unit 3 being taken offline on July 30, 2020 for a planned outage immediately preceding the start of refurbishment activities.

The decrease of electricity generation from the segment of 2.9 TWh for the nine months ended September 30, 2021, compared to the same period in 2020, was primarily due to Unit 3 of the Darlington GS undergoing refurbishment throughout the nine months ended September 30, 2021, compared to all four of the station's units generating electricity following the return to service of Unit 2 and prior to Unit 3 being taken offline in 2020. The decrease was also driven by the deferral of a planned cyclical maintenance outage for Unit 1 of the Darlington GS from the fall of 2020 to February 2021 as a result of changes made to the Darlington Refurbishment schedule in response to the COVID-19 pandemic in 2020.

The decreases in electricity generation of 0.4 TWh and 1.6 TWh from the Regulated – Hydroelectric business segment for the three and nine month periods ended September 30, 2021, respectively, compared to the same periods in 2020, were primarily due to lower water flows across most of Ontario.

The decreases in electricity generation of 0.2 TWh from the Contracted Hydroelectric and Other Generation business segment for the three and nine month periods ended September 30, 2021, compared to the same periods in 2020, were primarily due to lower water flows across the hydroelectric facilities in the United States.

The electricity generation from the Contracted Gas Generation business segment for the three months ended September 30, 2021 was comparable the same period in 2020. The increase of 1.1 TWh in electricity generated from the segment for the nine months ended September 30, 2021, compared to the same period in 2020, was primarily from the portfolio of combined cycle plants acquired in April 2020.

For the three and nine month periods ended September 30, 2021, Ontario's electricity demand as reported by the IESO was 34.9 TWh and 100.5 TWh, respectively, compared to 35.4 TWh and 99.5 TWh for the same periods in 2020, 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 surplus in Ontario was lower for the three and nine month periods ended September 30, 2021, compared to the same periods in 2020. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.3 TWh and 1.7 TWh during the three and nine month periods ended September 30, 2021, compared to 0.6 TWh and 3.1 TWh, respectively, for the same periods in 2020. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions was offset by the impact of a regulatory account authorized by the OEB. OPG did not forgo any electricity production at its nuclear generating stations due to SBG conditions.

Cash Flow from Operations

Cash flow provided by operating activities was $889 million for the three months ended September 30, 2021, compared to $1,007 million for the same period in 2020, and $1,965 million for the nine months ended September 30, 2021, compared to $2,547 million for the same period in 2020.

The decrease for the three months ended September 30, 2021, compared to the same period in 2020, was primarily due to lower revenue receipts reflecting lower overall electricity generation.

The decrease for the nine months ended September 30, 2021, compared to the same period in 2020, was primarily due to lower revenue receipts reflecting lower electricity generation from the Regulated – Nuclear Generation and the Regulated – Hydroelectric Generation business segments. The decrease was partially offset by net cash receipts from the operation of the combined cycle plants acquired in April 2020.

Capital Expenditures

Capital expenditures for the three and nine month periods ended September 30, 2021 and 2020 were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2021**	**2020**	**2021**	**2020**
Regulated – Nuclear Generation – Darlington Refurbishment Project	**209**	149	**603**	597
Regulated – Nuclear Generation – Excluding Darlington Refurbishment Project	**108**	112	**289**	262
Regulated – Hydroelectric Generation	**117**	72	**273**	192
Contracted Hydroelectric and Other Generation	**83**	51	**208**	103
Contracted Gas Generation	**5**	5	**18**	9
Other	**34**	21	**71**	81
Total capital expenditures [1]	**556**	410	**1,462**	1,244

[1] Includes net changes in accruals; excludes the acquisition of a portfolio of combined cycle assets on April 29, 2020.

Total capital expenditures increased by $146 million and $218 million for the three and nine month periods ended September 30, 2021, respectively, compared to the same periods in 2020.

The increase of $60 million in the capital expenditures on the Darlington Refurbishment project for the three months ended September 30, 2021, compared to the same period in 2020, was primarily due to execution activities on Unit 3 of the Darlington GS. The capital expenditures for the nine months ended September 30, 2021 were comparable to the same period in 2020.

Excluding the Darlington Refurbishment project, capital expenditures for the Regulated – Nuclear Generation business segment increased by $27 million for the nine months ended September 30, 2021, compared to the same period in 2020. This increase was partially due to higher capital expenditures relating to capital projects at the Darlington GS. The capital expenditures for the three months ended September 30, 2021 were comparable to the same period in 2020.

Capital expenditures for the Regulated – Hydroelectric Generation business segment increased by $45 million and $81 million for the three and nine month periods ended September 30, 2021, respectively, compared to the same periods in 2020. The increases in both periods reflected higher expenditures on the redevelopment of the Calabogie GS and asset overhaul programs, and capital investments at hydroelectric stations in the Eastern region.

Capital expenditures for the Contracted Hydroelectric and Other Generation business segment increased by $32 million and $105 million for the three and nine month periods ended September 30, 2021, respectively, compared to the same periods in 2020. The increases in both periods primarily reflected higher expenditures on the Little Long Dam Safety project.

Capital expenditures for the Contracted Gas Generation business segment for the nine months ended September 30, 2021 increased by $9 million, compared to the same period in 2020, primarily due to the acquisition of a portfolio of combined cycle plants in April 2020. The capital expenditures for the three months ended September 30, 2021 were comparable to the same period in 2020.

Further details on the Company's major projects can be found in the section, *Corporate Strategy, Core Business and Outlook* under the heading, *Project Excellence.*

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per MWh was $53.62 and $55.75 for the three and nine month periods ended September 30, 2021, respectively, compared to $50.36 and $46.60 for the same periods in 2020.

For the three months ended September 30, 2021, the increase was primarily due to higher capital expenditures in the Regulated – Hydroelectric Generation business segment and lower electricity generation from the Regulated – Hydroelectric Generation and Contracted Hydroelectric and Other business segments, partly offset by higher electricity generation from the Regulated – Nuclear Generation business segment.

For the nine months ended September 30, 2021, the increase was primarily due to lower electricity generation from the Regulated – Nuclear Generation and Regulated – Hydroelectric Generation business segments and higher OM&A expenses, excluding the impact of regulatory accounts, from the Regulated – Nuclear Generation business segment, largely due to the deferral of a planned cyclical maintenance outage for Unit 1 of the Darlington GS from the fall of 2020 to February 2021 in response to the COVID-19 pandemic.

SIGNIFICANT DEVELOPMENTS

Project Excellence

Darlington Refurbishment

In October 2021, the Darlington Refurbishment project concluded the second major segment of the Unit 3 refurbishment, the Disassembly segment, with the completion of the removal of fuel channel assemblies. The Unit 3 refurbishment has now transitioned into the third major segment, Reassembly, which includes the installation and reassembly of reactor components. Additionally, during the third quarter of 2021, the upper and middle feeder installation series has commenced. Planning activities for the refurbishment of Units 1 and 4 continue. The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Smoky Falls Dam Safety Project

During the third quarter of 2021, OPG initiated a project to improve the dam safety at the Smoky Falls hydroelectric GS, located along the Lower Mattagami River in northeastern Ontario. The project will rehabilitate 100-year-old spillway and sluiceway structures in compliance with provincial dam safety requirements. In September 2021, the project entered the execution phase, having completed the front-end engineering and design phase. OPG is progressing the procurement of critical services and advanced detailed engineering, design and permitting activities, as well as site preparation and mobilization. The project's expected in service date is in 2025, with a budget of $390 million. The Smoky Falls GS is reported in the Contracted Hydroelectric and Other Generation business segment.

Financial Strength

Settlement Agreement on OPG's Application for New Regulated Prices

In December 2020, OPG filed a five-year application with the OEB for new base regulated prices for production from the Company's nuclear facilities, determined under a custom incentive regulation framework used to establish the current regulated prices, with a proposed effective date of January 1, 2022. The application also requested new rate riders, effective January 1, 2022, to recover or repay the December 31, 2019 balances in most of the Company's regulatory accounts, less amounts previously approved for recovery or repayment through rate riders in effect to December 31, 2021, as well as the continuation of all applicable existing deferral and variance accounts.

Under the custom incentive regulation framework, OPG proposed a nuclear revenue requirement for each of the years 2022 to 2026 based on a forecast of operating costs and a return of and on rate base, as reduced by a stretch factor amount, to be recovered over a forecasted generation volume. The return on rate base is calculated using a formula-based rate of return on equity (ROE) established by the OEB on a generic basis and a company-specific deemed equity percentage applied to the rate base. As required by *Ontario Regulation 53/05*, the application proposed that nuclear base regulated prices incorporate a rate smoothing proposal to defer a portion of the nuclear revenue requirements in the Rate Smoothing Deferral Account for future collection. The public proceeding for OPG's application began in the first quarter of 2021.

In July 2021, OPG and the intervenors in OPG's application reached a proposed Settlement Agreement on most of the issues in the application , with the exception of the following: in-service capital additions for the Heavy Water Storage and Drum Handling Facility (HWSF) and associated regulatory account balances, the treatment of non-capital planning and preparation costs related to the nuclear small modular reactor (SMR) project at the Darlington nuclear site that are currently being recorded in an existing regulatory account, and rate smoothing. OPG's application includes in-service capital additions of approximately $510 million for the HWSF, a pre-requisite project forming part of the Darlington Refurbishment. The Settlement Agreement provides for a January 1, 2022 effective date for new regulated prices.

The Settlement Agreement was submitted for approval to the OEB on July 16, 2021. An oral hearing on the HWSF and SMR related unsettled issues was held between August 4, 2021 and August 6, 2021. On August 6, 2021, the OEB issued an oral decision approving the Settlement Agreement. The OEB's written decision on the HWSF and SMR related issues, along with written reasons for approving the Settlement Agreement, is expected in the fourth quarter of 2021. The OEB has stated that rate smoothing will be considered following the issuance of this written decision, at which time OPG expects final regulated prices reflecting the above decisions to be approved.

Highlights of the Settlement Agreement are outlined below.

Nuclear Rate Base, and Darlington Refurbishment

The Settlement Agreement provides for inclusion in rate base of non-HWSF in-service capital additions related to the Darlington Refurbishment project of approximately $6.4 billion between 2022 and 2026 as proposed in OPG's application, which comprises the forecasted return to service of Units 3, 1 and 4 of the Darlington GS upon refurbishment. This is in addition to the approximate $5.5 billion in non-HWSF Darlington Refurbishment in-service capital additions as of the end of 2021 previously approved by the OEB in establishing the 2017-2021 regulated prices. The Settlement Agreement also provides for recovery of non-capital costs for the Darlington Refurbishment project forecasted over the 2022-2026 period. The revenue requirement impact of differences between the approved forecasted and actual in-service capital additions and non-capital costs related to the project will continue to be recorded in the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05.* Any amounts sought for recovery that arise from the total cost of the project exceeding $12.8 billion and the impact of any future material changes to the project scope will be subject to a prudence review by the OEB in a subsequent proceeding.

Inclusive of the settled in-service capital additions related to the Darlington Refurbishment project and subject to the OEB's decision on the HWSF, the Settlement Agreement provides for a nuclear rate base of $13.1 billion by 2026. This reflects a reduction to OPG's requested forecasted non-Darlington Refurbishment in-service capital additions of approximately $60 million per year over the 2022-2026 period.

As part of the Settlement Agreement, the parties agreed that the undepreciated portion of nuclear rate base related to recently completed non-Darlington Refurbishment in-service capital, equal to approximately $300 million as of the end of 2021, will earn a return on deemed equity at the cost of long-term debt reflected in the revenue requirements over the 2022-2036 period. Thereafter, the remaining undepreciated amount will earn a return on deemed equity at the OEB-approved ROE rate in place at that time. The Settlement Agreement provides for an average cost of debt of 3.6 percent per annum over the 2022-2026 period, as requested in OPG's application.

Nuclear Revenue Requirement, and COVID-19 Impacts

Subject to the OEB's decision on the unsettled issues and the application of the OEB's prevailing ROE rate to determine the final return on rate base amount, OPG has calculated that the Settlement Agreement results in nuclear revenue requirements, net of stretch factor, totalling $16.1 billion over the 2022-2026 period, compared to $16.7 billion proposed in OPG's application. Contributing to the overall reduction is a decrease to the requested OM&A costs of approximately $55 million per year, the above noted decrease in the requested forecasted non-Darlington Refurbishment in-service capital additions, an increase and expansion of scope for the stretch factor, and the continuation of the existing deemed capital structure of 45 percent equity and 55 percent debt. The Settlement Agreement provides for an annual stretch factor of 0.6 percent for the 2022-2025 period and 0.3 percent for 2026, applied to most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as to the full non-Darlington Refurbishment capital related revenue requirement. The stretch factor applies starting in 2023 and compounds in each year to 2026, with certain adjustments for the planned end of commercial operations of the Pickering GS in 2025. The Settlement Agreement also reflects an increase in total forecasted nuclear production of 2.8 TWh over the 2022-2026 period.

Additionally, as part of the Settlement Agreement, OPG will credit ratepayers with $47 million related to the difference between the Company's net favourable electricity revenue impact and incremental OM&A expenses arising from the pandemic response over 2020 and 2021. During the third quarter of 2021, the Company recorded a corresponding increase in regulatory liabilities and a reduction in net income related to these impacts. Upon the OEB's approval of the Settlement Agreement, OPG ceased being subject to the deferral account for recording lost revenues and incremental costs related to the COVID-19 pandemic that was established by the OEB in March 2020.

Nuclear Liabilities, and Pension and OPEB Costs

Under the Settlement Agreement, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirements, as previously directed by the OEB in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of OPG's nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities) associated with the Bruce nuclear generating stations. The Settlement Agreement maintains the previously approved methodology for recovering the costs of the Nuclear Liabilities for OPG's regulated nuclear facilities and for the Bruce facilities and includes such costs for the 2022-2026 period in the amounts requested in OPG's application.

As proposed in OPG's application and confirmed by the Settlement Agreement, recovery of forecasted pension and OPEB costs in the nuclear revenue requirements will use the accrual method of accounting. As also proposed in the application, differences between the pension and OPEB costs under the accrual method of accounting and OPG's cash payments in respect of pension and OPEB plans, together with amounts recovered from the Pension & OPEB Cash Versus Accrual Differential Deferral Account, will be subject to asymmetric carrying charges in favour of customers at a prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. The Settlement Agreement also provides for the Pension and OPEB Cost Variance Account to record, for the nuclear facilities, differences between OPG's actual pension and OPEB costs determined using the accrual method and related tax impacts, and the corresponding forecast amounts reflected in the new regulated prices.

Variance and Deferral Accounts, and Earnings Sharing Mechanism

Subject to the OEB's decision on the HWSF, the Settlement Agreement provides for recovery of a net total of $702 million comprising amounts recorded in regulatory accounts as at December 31, 2019 and associated income tax impacts, including for the Pension & OPEB Cash Versus Accrual Differential Deferral Account, without adjustments. Together with the $47 million ratepayer credit related to impacts arising from the Company's pandemic response, these balances will be recovered or repaid effective January 1, 2022 over periods ranging from three to five years. Additionally, the Settlement Agreement defers the clearance of a portion equal to $40 million of amounts recorded as recoverable from customers in the Hydroelectric Surplus Baseload Generation Variance Account as at December 31, 2019 to a future proceeding addressing any impacts on OPG's regulated pricing mechanisms from the IESO's Market Renewal Program. The total net settled balance of $702 million comprises $787 million in recoverable balances previously approved but not yet authorized for collection by the OEB, and newly approved net refundable balances of $85 million. The associated income tax impacts included for recovery were previously recorded as part of the regulatory asset for deferred income taxes.

The Settlement Agreement provides for the continuation of all applicable existing regulatory accounts and acknowledges that OPG may file a separate application during the 2022-2026 period seeking clearance of regulatory account balances accumulated since they will have been last cleared in this proceeding.

The Settlement Agreement establishes a mechanism for customers to share, on a 50 percent basis, in the earnings of OPG's combined nuclear and regulated hydroelectric business that exceed a 100 basis points deadband to the OEB-approved ROE rate, assessed on a five-year cumulative basis over the 2022-2026 period. Any such amounts shared with customers will be recorded in a new deferral account for disposition following the five-year period. The custom incentive regulation framework will also continue to include a symmetrical 300 basis points threshold around the approved ROE rate as the OEB's expected range of financial performance outcomes. Return on equity performance for the purposes of the earnings sharing mechanism and the 300 basis points threshold will be calculated on the deemed capital structure reflected in the approved regulated prices.

Additionally, the Settlement Agreement provides for the establishment of new regulatory accounts to record, effective January 1, 2022, the financial impacts of transition to and implementation of IFRS from US GAAP in the event that OPG adopts IFRS for financial reporting purposes to meet the requirements of *Securities Act* (Ontario), and the nuclear revenue requirement impact of capital expenditures and operating costs for OPG's planned new corporate campus in Clarington, Ontario. It also provides for the establishment, on a final basis effective January 1, 2021, of a deferral account to record the revenue requirement impacts arising from changes to Nuclear Liabilities and depreciation and amortization expenses as a result of changes to the accounting end-of-life assumptions for the Pickering GS, including those that became effective December 31, 2020.

Social Licence

Gold Designation from Canadian Council for Aboriginal Business

In August 2021, OPG was awarded the Gold Designation under the Canadian Council for Aboriginal Business' (CCAB) Progressive Aboriginal Relations (PAR) program. PAR Gold companies demonstrate sustained leadership in Indigenous relations and a commitment to working with Aboriginal businesses and communities, through innovative programs and engagement. The Gold level certification recognizes OPG as a national best-practices organization with a demonstrated commitment in the area of Indigenous relations. The designation is determined by a jury of Indigenous professionals that reports on measurable outcomes and initiatives in four key areas: leadership actions, employment, business development, and community relations.

Launch of OPG's Inaugural Reconciliation Action Plan

In October 2021, OPG launched its inaugural Reconciliation Action Plan. Building on the Company's long-standing commitment to Indigenous communities, the action plan outlines the Company's overall goals and the supporting actions OPG will take to advance reconciliation in a number of key areas. OPG has set a goal of growing the Company's existing economic impact for Indigenous communities and businesses to $1 billion over the next 10 years through ongoing operations, projects and initiatives. The Company will also develop strategic approaches to recruitment with the objective of increasing the representation of Indigenous employees across all levels at OPG. The action plan serves as a roadmap for how the Company will work with Indigenous communities, businesses and organizations as well as other key partners for advancing reconciliation.

CORPORATE STRATEGY, CORE BUSINESS 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 the customers and Shareholder.

The following sections provide an update to OPG's disclosures in the 2020 annual MD&A related to its four business imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these imperatives as part of OPG's corporate strategy is included in the 2020 annual MD&A in the sections, *The Company* and *Core Business* 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 assets, through a highly trained and engaged workforce. Workplace safety and public safety are overriding priorities in all activities performed at OPG.

Electricity Generation Production and Reliability

- OPG continues to take action to protect the health and safety of the Company's employees, partners and communities against COVID-19, while ensuring continued safe and reliable operation of the Company's generating assets and advancing key projects. During the third quarter of 2021, OPG implemented a vaccination standard, which includes the expectation that all employees, contractors and visitors at OPG's generating stations and other sites are fully vaccinated against COVID-19 or adhere to additional safety precautions. In addition, OPG has implemented a return to workplace plan for employees not directly involved in operating the generating facilities and who have been working remotely under a work-from-home strategy during the pandemic, based on a phased approach that ensures the transition is implemented safely, aligns with public health guidelines, and considers the needs of different work environments. For further details on OPG's response to COVID-19, refer to the section, *Risk Management* under the heading, *COVID-19 Pandemic*.

- The Canadian nuclear sector is subject to rigorous regulatory oversight by the CNSC, which includes the requirement for OPG to implement and maintain a fitness for service program for pressure tubes, including limits on hydrogen equivalent concentration. In July 2021, during Bruce Power's fuel channel inspection program, higher-than-anticipated hydrogen equivalent concentration were measured on two nuclear units at the Bruce nuclear generating stations. Results showed higher concentration in a limited, localized volume in the upper portion of the pressure tube. Although OPG does not operate the Bruce nuclear generating stations, in late July 2021, the CNSC issued an Order requiring both OPG and Bruce Power to seek authorization from the CNSC prior to restart of nuclear units following any outage that results in the cool down of the heat transport system. Following a review of evidence and approval process, in November 2021, the CNSC confirmed that OPG has satisfied the terms of the Order, and consequently, OPG's nuclear generating units are no longer subject to the Order and have the CNSC's authorization to restart nuclear units following any planned or unplanned outages.

- One of OPG's objectives is to maximize the safe and reliable operating life of the Pickering GS units. In connection with this objective, OPG continues to execute planned work required to enable safe and reliable operation of the plant to the planned end of life dates, including commitments required under the previously established Periodic Safety Review (PSR) and associated Integrated Implementation Plan (IIP). The PSR, a comprehensive assessment of the station's design and operation, confirmed that there is a high level of safety throughout the continued operation of the station to 2024.

In September 2021, CNSC staff affirmed that OPG has completed all PSR requirements and resolution actions documented in the IIP. The CNSC staff concurred that OPG has implemented the results of the PSR to ensure the continued safe and reliable commercial operation of the Pickering GS to the end of 2024. With the completion of all IIP actions required for the Pickering GS operating licence, CNSC staff confirmed that no further quarterly and annual reporting is required. OPG continues to perform additional technical analysis and inspections to confirm fitness-for-service of fuel channels and other major station components in support of optimizing the station's planned shutdown sequence to 2025, including confirming the validity of the PSR and IIP. OPG is required to notify the CNSC of the results of this PSR and IIP reassessment by the end of 2022, in support of the CNSC's approval required for post-2024 commercial operation. Operating any of the Pickering GS units past December 31, 2024 is subject to the CNSC's regulatory approval through a public hearing process.

Project Excellence

OPG is undertaking a number of generation development and other projects to maximize the value of and expand its generating fleet in support of Ontario's electricity system, striving for excellence in the planning and delivery of all capital and maintenance projects across the organization. The status of OPG's major projects is outlined below.

Project *(millions of dollars)*	**Capital expenditures Year-to-date** [1]	**Capital expenditures Life-to-date**	**Approved budget**	**Expected in-service date**	**Current status**
Darlington Refurbishment	603	8,049	12,800 [2]	Second unit – 2024 Last unit – 2026	Unit 3 refurbishment is progressing on schedule and has entered the Reassembly segment. The project is tracking to the overall timeline to refurbish all four of the station's units by the end of 2026. For further details, see below.
Little Long Dam Safety Project	162	264	650	2023	During the third quarter of 2021, rock excavation activities below the Adam Creek spillway structure on the Little Long Reservoir and the concrete placement of the new bays adjacent to the sluicegates continued. The project also commenced the replacement of existing gates and major concrete placement on two new gates. The project is expected to be placed in service in 2023 and is tracking on budget.
Sir Adam Beck I GS Units G1 and G2 Replacement	32	86	128	2022	During the third quarter of 2021, OPG commenced the G2 unit turbine and generator installation, including the tower assembly, runner and shaft assembly. The installation and machining of G1 scroll case was also completed during the third quarter of 2021 and the project has commenced the installation of the G1 unit turbine. The project is expected to be placed in service in 2022 and is tracking on budget.

[1] Year-to-date represents capital expenditures as at September 30, 2021.
[2] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.

Project *(millions of dollars)*	Capital expenditures Year-to-date [3]	 Life-to-date	Approved budget	Expected in-service date	Current status
Calabogie Hydroelectric GS	42	72	137	2022	During the third quarter of 2021, OPG continued construction on the new powerhouse, including placement of major components of the new G1 and G2 units. The old powerhouse substructure has been removed and excavation of the new tailrace area has commenced. In addition, the downstream cofferdam was placed in-service during the third quarter of 2021, as planned. The construction of the upstream cofferdam is expected to be completed in the fourth quarter of 2021. The project is expected to be placed in service in 2022 and is tracking toward a total cost of $145 million.
Smoky Falls Dam Safety Project	10	12	390	2025	The project to improve the dam safety at the Smoky Falls GS entered the execution phase in September 2021, having completed the front-end engineering and design phase. The project is expected to be placed in service in 2025. For further details, refer to the section, *Significant Developments* under the heading, *Smoky Falls Dam Safety Project*.
Ranney Falls Hydroelectric GS	1	72	77	2022	During final commissioning of the new 10 MW single-unit powerhouse on the existing Ranney Falls GS site in September 2020, the generator sustained damage and commissioning activities were halted. Work is underway by the vendor to repair and reassemble the unit at their own cost. Based on current technical assessments, the revised in-service date is expected to be in 2022. The project continues to track within budget.

[3] Year-to-date represents capital expenditures as at September 30, 2021.

Darlington Refurbishment

The Darlington GS 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 refurbishment of the first unit, Unit 2, was completed in June 2020. The second unit, Unit 3, commenced refurbishment in September 2020 and is scheduled to be returned to service in the first quarter of 2024. The planning, pre-requisite and execution work for Units 3, 1 and 4 refurbishments has and will incorporate the benefits of experience with Unit 2 and additional strategic improvements. The last unit to undergo refurbishment is scheduled to be completed by the end of 2026.

Unit 3 refurbishment activities are progressing on schedule, incorporating continued COVID-19 protective measures. In August 2021, the project completed the removal of end fittings and subsequently completed the removal of pressure tubes and calandria tubes in October 2021, marking the end of the Disassembly segment. The Unit 3 refurbishment project has now entered the third major segment, Reassembly, which involves installing and inspecting new reactor components, including new feeder tubes and fuel channel assemblies. During the third quarter of 2021, the project also commenced the upper and middle feeder installation series on Unit 3. The installation will include 960 new feeder tubes and will be completed in two segments, starting with the upper and middle feeders and followed by the lower feeders.

Planning and pre-requisite activities for the refurbishment of subsequent units, Unit 1 and Unit 4, are progressing as planned. As of September 30, 2021, approximately $438 million has been invested in planning and pre-requisite activities related to the refurbishment of Unit 1 and Unit 4.

OPG continues to assess and seek ways to manage the impact of the COVID-19 pandemic on the project's total cost, which is otherwise continuing to track to the $12.8 billion budget.

Upgrade and Rehabilitation of Hydroelectric Generating Stations

OPG is executing on a planned 20-year turbine and generator overhaul program of its hydroelectric generating units across Ontario. The estimated $2.5-billion program will ensure that generating units can continue to operate efficiently and reliably while supporting OPG's net-zero carbon goals. During the third quarter of 2021, OPG completed the overhaul and upgrade of Unit 5 of the Sir Adam Beck I GS to ensure continued reliable operations for the next 30 years.

Financial Strength

As a commercial enterprise, OPG's financial priority is to ensure a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and supports expansion of the business.

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 return on the Shareholder's investment, while seeking to minimize the impact on electricity customers through continuous improvement in the Company's cost structure.

For regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and prudent growth of rate base earning a return. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. OPG is focused on demonstrating in its applications for regulated prices that the costs required to operate and invest in the Company's regulated assets are reasonable and being prudently incurred and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate return. For further information on OEB-approved rate base levels, refer to OPG's 2020 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The following table presents the OEB-authorized regulated prices for electricity generated from OPG's regulated facilities in Ontario for the period from January 1, 2020 to December 31, 2021 in effect as of the date of this MD&A:

($/MWh)	**2020**	**2021**
Regulated – Nuclear Generation		
Base regulated price [1]	85.00	**89.70**
Interim period shortfall rider [2]	5.64	**-**
Deferral and variance account rate riders [3]	4.32	**6.13**
Total regulated price	94.96	**95.83**
Regulated – Hydroelectric Generation		
Base regulated price	43.15	**43.88**
Interim period shortfall rider [2]	0.24	**-**
Deferral and variance account rate riders [3]	2.26	**2.05**
Total regulated price	45.65	**45.93**

[1] Base regulated prices for the nuclear facilities were established using a rate smoothing approach that defers a portion of each year's approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account. Base regulated prices for the nuclear facilities do not include amounts deferred in the Rate Smoothing Deferral Account.

[2] In its payment amounts order issued in March 2018, the OEB authorized separate rate riders on OPG's regulated electricity generation to allow for the recovery of the revenue shortfall between the base regulated prices approved with an effective date of June 1, 2017 and the previously approved base regulated prices that OPG continued to receive during the interim period between June 1, 2017 and February 28, 2018. The interim period revenue shortfall amount approved for recovery was recognized as an increase to revenue and a regulatory asset and was collected subsequently through rate riders over the March 1, 2018 to December 31, 2020 period.

[3] Differences in recovery of the approved regulatory account balances due to differences between forecasted electricity generation used to set the rate riders and actual electricity generation upon which the rate riders are collected are trued-up with customers through OEB-authorized variance accounts.

Pursuant to the OEB's March 2018 payment amounts order, $391 million of approved nuclear revenue requirement was deferred in the Rate Smoothing Deferral Account for future collection in 2020, which has helped to lower electricity prices for customers. As part of the order, the OEB also determined that no portion of the nuclear revenue requirement would be deferred in 2021. Amounts deferred in the Rate Smoothing Deferral Account are recorded as revenue in the Regulated – Nuclear Generation business segment in the period to which the underlying approved revenue requirement relates. *Ontario Regulation 53/05* requires the OEB to authorize recovery of the deferred amounts, together with interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, over a period not to exceed ten years following the end of the Darlington Refurbishment project.

In December 2020, OPG filed a five-year application with the OEB for new base regulated prices for production from the nuclear facilities, determined under a custom incentive regulation framework consistent with the findings in the OEB's decision on OPG's 2017-2021 application for regulated prices, with a proposed effective date of January 1, 2022. In July 2021, OPG and the intervenors in OPG's application reached a Settlement Agreement on most of the issues in the application. The Settlement Agreement was approved by the OEB on August 6, 2021, with a January 1, 2022 effective date for new regulated prices. Final regulated prices reflecting the Settlement Agreement will be approved following the OEB's pending decision on the unsettled issues, which is expected to be issued in the fourth quarter of 2021. For further details on OPG's application and the Settlement Agreement, refer to the section, *Significant Developments* under the heading, *Settlement Agreement on OPG's Application for New Regulated Prices*.

Pursuant to *Ontario Regulation 53/05*, the base regulated price for OPG's hydroelectric electricity generation (hydroelectric base regulated price) for the period from January 1, 2022 to December 31, 2026 will be equal to the 2021 hydroelectric base regulated price, which the OEB approved at $43.88/MWh effective January 1, 2021 pursuant to the annual formulaic adjustment.

For generation assets that do not form part of the rate-regulated operations, OPG seeks to secure long-term revenue arrangements that support an appropriate return on the investment. In line with this strategy, all of OPG's non-regulated facilities in Ontario continue to be subject to ESAs with the IESO or other long-term contracts.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project and other commitments and long-term obligations. In addition to funds generated from operations, OPG utilizes the following primary funding sources: commercial paper; letters of credit; credit facilities; long-term debt sourced from the Ontario Electricity Financial Corporation (OEFC), an agency of the Province; public debt offerings; and private placement project financing.

The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where the characteristics of the project support such financing.

Credit Ratings

Maintaining an investment grade credit rating supports OPG's ability to access cost effective financing. As at September 30, 2021, the Company's credit ratings were as follows:

Type of Rating	DBRS Limited (DBRS) [1]	S&P Global Ratings (S&P) [2]	Moody's Investors Service (Moody's)
Issuer rating	A (low)	BBB+	A3
Senior unsecured debt	A (low)	BBB+	A3
Trend/Outlook	Stable	Stable	Stable
Commercial paper program – Canada	R-1 (low)	A-1 (low)	NR [1]
Commercial paper program – US	NR [3]	A-2	P-2

[1] In April 2021, DBRS confirmed OPG's issuer rating at A (low), senior unsecured debt rating at A (low) and Canadian commercial paper rating at R-1 (low), all with Stable trends.
[2] In August 2021, S&P confirmed OPG's ratings including BBB+ issuer's rating with stable outlook, BBB+ senior unsecured debt rating and A-1 (low) Canada commercial paper rating.
[3] NR indicates no rating assigned.

Additional discussion of the Company's credit facilities and liquidity can be found in the section, *Liquidity and Capital Resources*.

Building Our Business

OPG strives to be a leader in the North American transition toward a low carbon economy while maintaining and expanding the Company's scale and energy industry leadership through the pursuit of commercial-based opportunities. Aligned with OPG's Climate Change Plan, the strategy considers the Company's financial position and encompasses the renewal and expansion of the Company's portfolio of electricity generating assets, including redevelopment of existing sites, new development and business acquisitions, as well as the expansion and innovation of the business beyond core generation operations. Opportunities are evaluated based on strategic benefits, financial returns, risk profile and operating synergies.

Nuclear Small Modular Reactors

OPG maintains a ten-year site preparation licence granted by the CNSC in 2012 in relation to the potential construction of new nuclear reactors at the Company's Darlington site with up to 4,800 MW of generating capacity. In October 2021, the CNSC approved OPG's application to renew the licence for a period of ten years, expiring in October 2031. The site preparation licence authorizes OPG to prepare the Darlington site for potential future construction and operation of a new nuclear generating station. Construction and operation of new nuclear reactors at the Darlington site is subject to the CNSC's regulatory approval through a separate application and licensing process, which would include public participation.

Social Licence

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, and strives to be a leader in climate change action.

Further details on social licence activities and initiatives can be found in the section, *Environmental, Social, Governance and Sustainability*.

Outlook

<u>Operating Performance</u>

OPG expects net income for the 2021 year to be lower relative to 2020, driven by the impact of the Company's response to the onset of COVID-19 pandemic in 2020 on the Darlington Refurbishment schedule and the associated changes in the station's cyclical maintenance outage schedule. This includes a full year of Unit 3 refurbishment in 2021, the deferral of a planned cyclical maintenance outage for Unit 1 from the fall of 2020 to February 2021, and the addition of a new planned cyclical maintenance outage for Unit 4 in the fall of 2021, all of which have or are expected to reduce electricity generation and revenue from the Regulated – Nuclear Generation business segment in 2021. The year-over-year increase in planned outage activity at the Darlington GS is also expected to continue to result in additional OM&A expenses in 2021. These impacts are expected to be partially offset by higher electricity generation and lower OM&A expenses from the Pickering GS in 2021 in line with the station's cyclical maintenance outage schedule. Electricity generation from the Regulated – Nuclear Generation business segment in the fourth quarter of 2021 is expected to be impacted by a Unit 5 planned outage at the Pickering GS.

The year-over-year decrease in net income for 2021 is expected to be partially offset by a full year of earnings from the increased OEB-approved nuclear rate base related to the return to service of the refurbished Unit 2 at the Darlington GS in June 2020, and a full year of earnings from the combined cycle plants acquired in April 2020. The OEB's decision on the unsettled issues in OPG's application for new regulated prices, expected in the fourth quarter of 2021, may adversely impact net income for the 2021 year.

Several regulatory accounts are expected to continue to reduce the relative variability of the regulated business segments' contribution to the Company's net income, particularly for the Regulated – Hydroelectric Generation business segment. This includes accounts that capture the gross margin impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations.

The ESAs in place for the Ontario-based non-regulated assets reported in the Contracted Hydroelectric and Other Generation business segment are expected to contribute a generally stable level of earnings in 2021 compared to 2020. Earnings from the US-based hydroelectric facilities reported in the segment are subject to variability in water flows and the impact of wholesale electricity prices on uncontracted facilities. Revenue from uncontracted US-based hydroelectric facilities continues to represent a small portion of OPG's overall revenue.

The Company's operating results in 2021 may be impacted in the event additional actions are necessary to respond to the COVID-19 pandemic.

Enterprise Total Generating Cost

OPG forecasts the Enterprise TGC to continue to be higher in 2021, compared to 2020, primarily due to lower electricity generation and additional OM&A expenses from the Darlington GS, described above.

In general, lower nuclear electricity generation due to the Darlington Refurbishment outages will continue to negatively impact the Enterprise TGC for the duration of the project. The Enterprise TGC can also be negatively affected by lower hydroelectric generation due to outages for various major rehabilitation and operational projects. Ongoing variability in sustaining capital expenditure programs, planned nuclear outages and water flows can also contribute to fluctuations in the Enterprise TGC results.

Nuclear Segregated Funds

OPG's operating results are affected by earnings on the nuclear fixed asset removal and nuclear waste management segregated funds (Nuclear Segregated Funds) as part of the Regulated – Nuclear Waste Management business segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the Ontario Nuclear Funds Agreement (ONFA), rates of return earned in a given period are subject to volatility due to financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario consumer price index (CPI). This volatility can cause fluctuations in the Company's net income in the short term. The volatility is reduced by the impact of an OEB-authorized regulatory account and during periods when the funds are in a fully funded or overfunded position.

As at September 30, 2021, the Decommissioning Segregated Fund was overfunded by approximately 39 percent and the Used Fuel Segregated Fund was overfunded by approximately 4 percent. Variability in asset performance due to volatility in financial markets and changes in Ontario CPI, including as a result of changes in economic conditions or changes in funding liability estimates when the ONFA reference plan is updated, may reduce the funded status of either or both funds in the future. No overall contributions to the Nuclear Segregated Funds are required until the end of 2021, when the ONFA reference plan is next scheduled to be updated. The new ONFA reference plan and associated contribution requirements are in the process of being developed and will be subject to the Province's review and approval.

Changes in funding liability estimates upon an ONFA reference plan update can result in adjustments to the values of Nuclear Segregated Fund assets reported on the consolidated balance sheet, as these values are limited to the cost estimate of the funding liability based on the most recently approved ONFA reference plan, plus a portion of the Decommissioning Segregated Fund surplus that may be directed to the Used Fuel Segregated Fund in certain circumstances. On the consolidated statements of income, such adjustments are recorded as increases or decreases to earnings on the Nuclear Segregated Funds.

In line with the ONFA reference plan update process, OPG is continuing to progress a comprehensive reassessment of the assumptions and baseline cost estimates underlying the Nuclear Liabilities recorded in the consolidated financial statements. Any resulting changes in the related asset retirement costs will be capitalized as part of the carrying amount of nuclear fixed assets in service.

Capital Expenditures

OPG's total forecasted capital expenditures for the 2021 year are approximately $2.3 billion, excluding any acquisition-related activity. The 2021 forecast is higher than the capital expenditures in 2020, excluding the acquisition of combined cycle plants in April 2020, primarily reflecting a full year of execution activities on the refurbishment of Unit 3 of the Darlington GS, advancement of the Little Long Dam Safety project to the component installation phase, the redevelopment of the Calabogie GS and planned hydroelectric asset overhaul programs.

Financing and Liquidity

The Company expects to continue to generate a lower level of cash flow from operating activities in 2021 compared to 2020, due to a reduction in electricity generation and higher OM&A expenses from the Darlington GS, described above. This is expected to be partially offset by an increase in revenue receipts from the combined cycle plants acquired in April 2020.

Taking into account the forecasted capital expenditure program for the 2021 year, OPG expects existing funding sources to continue to be sufficient to meet financing requirements and support ongoing liquidity. Further details of

OPG's credit facilities can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

ENVIRONMENTAL, SOCIAL, GOVERNANCE AND SUSTAINABILITY

OPG recognizes that operating in a safe, sustainable and inclusive manner is directly connected to business success and is expected by customers, the Company's stakeholders and Shareholder. As Ontario's largest clean energy provider, the Company strives to be a leader in sustainability and climate change action through the implementation of operational and growth strategies that minimize the Company's environmental footprint, support reductions in greenhouse gas (GHG) emissions, and increase resilience to climate change impacts, while taking into account impacts on customers. Central to OPG's Environmental, Social, Governance and Sustainability focus is its commitment to becoming a global equity, diversity and inclusion (ED&I) best practice leader by 2030.

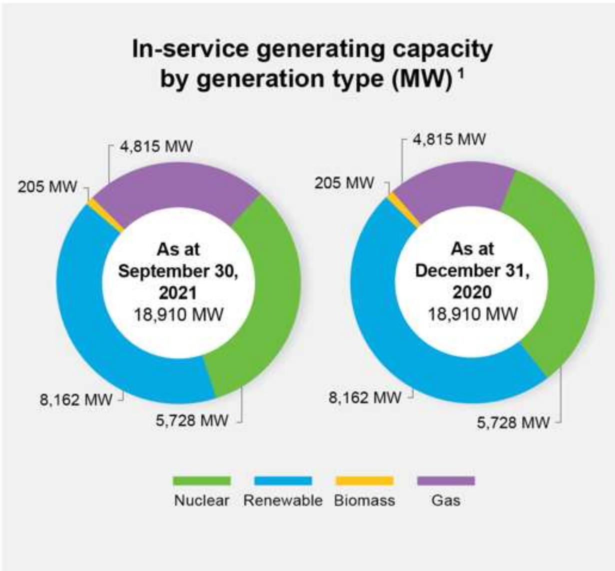
Climate Change

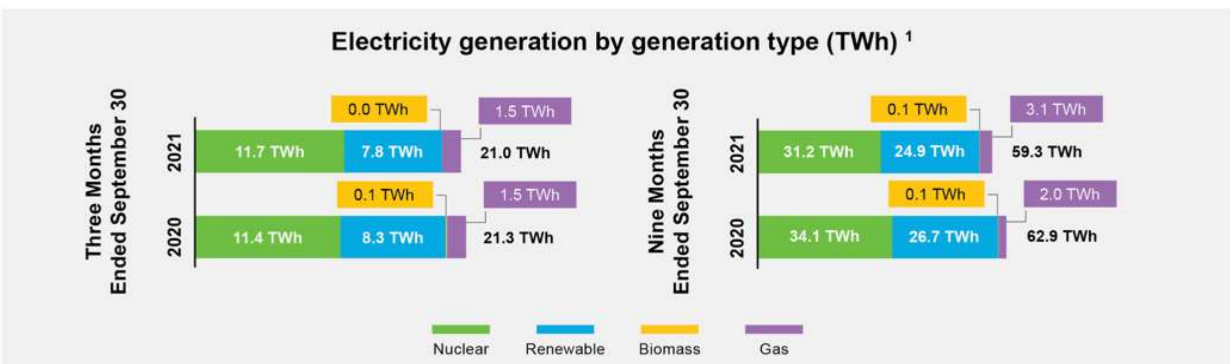
OPG's Climate Change Plan commits the Company to being a net-zero carbon company by 2040 and taking action to drive efficient, economy-wide carbon reduction in Ontario and beyond. In advancing these goals, the Company continues to seek opportunities to maximize the decarbonizing potential of its generating assets, advance the electrification of other sectors of the economy such as transportation, and invest in technologies that can make a further meaningful and immediate impact on climate change. For discussion of the actions being taken by OPG in support of the Climate Change Plan, refer to the sections, *Corporate Strategy, Core Business and Outlook*, under the heading, *Financial Strength – Building Our Business*.

Climate-Related Performance and Key Metrics

OPG continues to determine the most relevant climate-related impacts for the business in the context of its Environmental, Social, Governance and Sustainability framework and is engaged in the development of consistent industry metrics to quantify the level of achieved climate change resilience. OPG is in the process of developing such quantitative metrics and targets for climate change adaptation as part of an effort to integrate climate considerations into business processes. In the meantime, OPG has identified certain initial metrics that it considers relevant to stakeholders, as outlined below.

Climate change metrics





[1] Includes OPG's proportionate share of in-service generating capacity and electricity generation from co-owned and minority-held facilities, as applicable. Gas category includes the dual-fuelled oil and gas Lennox GS and the Company's combined cycle plants operated through Atura Power.

In-service generating capacity by generation type	Total in-service generating capacity from each of low-carbon emitting and gas generation sources as at September 30, 2021 is the same as at December 31, 2020. The gas generation assets are an important component of maintaining the reliability of Ontario's electricity system and enable intermittent sources of renewable energy such as wind and solar.
Electricity generation by generation type	During the three and nine month periods ended September 30, 2021, approximately 93 percent and 95 percent, respectively, of OPG's total electricity generation was supplied by low-carbon sources. Electricity generation from low-carbon sources for the three months ended September 30, 2021 was comparable to the same period in 2020. The decrease for the nine months ended September 30, 2021 was primarily due to lower electricity generation from the Darlington GS and lower water flows across the majority of the hydroelectric fleet.
Revenue by facility category	Revenue from low-carbon generation decreased for the three and nine month periods ended September 30, 2021, compared to the same periods in 2020, primarily due to lower revenue from the Regulated – Nuclear Generation business segment. For the nine months ended September 30, 2021, the increase in revenue from gas generation was primarily due to the acquisition of combined cycle plants in April 2020.

Equity, Diversity and Inclusion

OPG is committed to workplace ED&I as part of a culture in which all employees, contractors and business partners are treated fairly and respectfully. OPG believes that ED&I is integral to fostering an innovative, healthy and engaged workforce, and is therefore fundamental to the achievement of the Company's strategic goals.

OPG is advancing its corporate commitment to ED&I through comprehensive programming and adherence to the values set out in the Company's Code of Business Conduct. During the third quarter of 2021, OPG continued to engage stakeholders across the enterprise on its 10-year ED&I strategy and is incorporating feedback received to date to ensure the Company's approach responds to and incorporates employee experiences and perspectives. OPG is preparing to launch the ED&I strategy by early 2022.

OPG is a member of 30% Club Canada, a campaign which aims to have 30 percent of board seats and senior management positions in the Canadian business community to be held by women by 2022. As at September 30, 2021, women comprised 60 percent of independent board members of OPG's Board of Directors.

Indigenous Relations

The Company believes in building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario and continues to support procurement, employment and education opportunities with Indigenous communities. OPG seeks to establish these relationships based on a foundation of respect, transparency and mutual responsibility. OPG's commitment in the area of Indigenous relations includes, where appropriate, pursuing generation-related development partnerships on the basis of long-term commercial arrangements and other joint projects proximate to the Company's present and future operations. For further details, refer to the section, *Significant Developments – Social Licence*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars – except where noted)	Three Months Ended September 30 2021	Three Months Ended September 30 2020	Nine Months Ended September 30 2021	Nine Months Ended September 30 2020
Electricity Generation (TWh)	**11.7**	11.4	**31.2**	34.1
Revenue	**964**	1,210	**2,965**	3,492
Fuel expense	**63**	78	**192**	230
Gross margin	**901**	1,132	**2,773**	3,262
Operations, maintenance and administration expenses	**400**	562	**1,596**	1,697
Property taxes	**7**	7	**20**	20
Earnings before interest, income taxes, depreciation and amortization	**494**	563	**1,157**	1,545
Depreciation and amortization expenses	**146**	207	**436**	616
Earnings before interest and income taxes	**348**	356	**721**	929

For the three months ended September 30, 2021, earnings before interest and income taxes from the segment decreased by $8 million, compared to the same period in 2020, primarily due to a decrease in revenue reflecting lower amounts of $98 million recorded in the Rate Smoothing Deferral Account, as well as the impact of the Settlement Agreement related to OPG's response to the COVID-19 pandemic discussed below. These impacts were largely offset by lower depreciation and amortization expenses of $75 million, excluding amortization expense related to the recovery of regulatory account balances, an increase in revenue of $56 million from a higher OEB-approved nuclear base regulated price and an increase in revenue from higher electricity generation of 0.3 TWh during the third quarter of 2021.

The decrease in segment earnings before interest and income taxes of $208 million for the nine months ended September 30, 2021, compared to the same period in 2020, was primarily due to a decrease in revenue as a result of lower electricity generation of 2.9 TWh and lower amounts of $293 million recorded in the Rate Smoothing Deferral Account. These impacts were partially offset by an increase in revenue of $150 million from a higher OEB-approved nuclear base regulated price and lower depreciation and amortization expenses of $222 million excluding amortization expense related to the recovery of regulatory account balances.

As part of the Settlement Agreement, OPG agreed to credit ratepayers with $47 million related to the difference between the Company's net favourable electricity revenue impact and incremental OM&A expenses arising from the pandemic response over 2020 and 2021. The net impact to the Regulated – Nuclear Generation business segment was a reduction of EBIT in the amount of $58 million for both the three and nine month periods ended September 30, 2021, comprising a reduction in revenue of $192 million, a reduction in fuel expense of $11 million and a net reduction in OM&A expenses of $124 million.

For both the three and nine month periods ended September 30, 2021, depreciation and amortization expenses decreased due to amounts recorded as recoverable from customers in regulatory accounts in connection with differences in the current accounting end-of-life assumptions for the Pickering GS from those assumed in the nuclear base regulated price effective January 1, 2021. The nuclear base regulated price reflects recovery of a lower amount of depreciation expense related to the Pickering GS as it was set on the basis of a December 31, 2020 accounting end-of-life date for the station in effect at the time of OPG's application to the OEB for the 2017-2021 base regulated prices. Subsequent to the OEB's decision on the application, the Company achieved sufficient confidence to extend the station's end-of-life assumptions beyond December 31, 2020. The resulting differences in depreciation expense over the period are recorded in OEB-authorized regulatory accounts.

The planned and unplanned outage days at the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	**2020**	**2021**	**2020**
Planned Outage Days				
Darlington GS [1]	**-**	33.5	**79.2**	35.6
Pickering GS	**22.8**	92.4	**222.0**	297.5
Unplanned Outage Days				
Darlington GS [1]	**11.0**	12.9	**42.8**	17.0
Pickering GS	**23.7**	32.7	**63.2**	47.9

[1] The planned and unplanned outage days exclude unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the reported planned and unplanned outage days during its refurbishment period of October 15, 2016 to June 4, 2020 and Unit 3 of the Darlington GS is excluded since commencing refurbishment on September 3, 2020.

The decrease in planned outage days at the Darlington GS for the three months ended September 30, 2021 was primarily due to the Unit 3 single-fuel channel replacement planned outage that commenced on July 30, 2020 and was completed immediately before commencing Unit 3 refurbishment execution activities on September 3, 2020. Planned outage days at the Darlington GS increased for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to the deferral of a planned cyclical maintenance outage for Unit 1 of the Darlington GS from the fall of 2020 to February 2021 in response to the COVID-19 pandemic, partially offset by the single-fuel channel replacement planned outage in the third quarter of 2020.

The decrease in planned outage days at the Pickering GS for the three and nine month periods ended September 30, 2021, compared to the same periods in 2020, was primarily due to the station's cyclical maintenance outage schedule.

The increase in unplanned outage days at the Darlington GS for the nine months ended September 30, 2021, compared to the same period in 2020, was primarily due to non-routine instrumentation maintenance work and unplanned fuel handling maintenance activities at the station.

Unplanned outage days at the Pickering GS increased for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to unplanned fuel handling maintenance activities at the station during the first quarter of 2021.

The Unit Capability Factors for the Darlington and Pickering nuclear generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	**2020**	**2021**	**2020**
Unit Capability Factor *(%)* [1]				
Darlington GS	**99.7**	88.3	**86.5**	93.4
Pickering GS	**94.1**	78.4	**83.5**	79.4

[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 during its refurbishment period of October 15, 2016 to June 4, 2020 and Unit 3 of the Darlington GS is excluded since commencing refurbishment on September 3, 2020.

The Unit Capability Factor at the Darlington GS increased for the three months ended September 30, 2021, compared to the same period in 2020, primarily due to fewer planned outage days. For the nine months ended September 30, 2021, the Unit Capability Factor decreased compared to the same period in 2020, primarily due to a higher number of planned and unplanned outage days. The Unit Capability Factor at the Pickering GS increased for three and nine month periods ended September 30, 2021, compared to the same periods in 2020, primarily due to fewer planned outage days.

Regulated – Nuclear Waste Management Segment

(millions of dollars – except where noted)	**Three Months Ended September 30** **2021**	**2020**	**Nine Months Ended September 30** **2021**	**2020**
Revenue	**52**	33	**146**	102
Operations, maintenance and administration expenses	**52**	33	**146**	102
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**271**	259	**809**	781
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(243)**	(234)	**(722)**	(693)
Loss before interest and income taxes	**(28)**	(25)	**(87)**	(88)

The segment loss before interest and income taxes for the three and nine month periods ended September 30, 2021 was comparable to the same periods in 2020. Higher earnings on the Nuclear Segregated Funds were offset by an increase in accretion expense on the Nuclear Liabilities.

The higher earnings from the Nuclear Segregated Funds were primarily due to the growth in the present value of the underlying funding liabilities per the current approved ONFA reference plan in effect since January 1, 2017. As both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund were in an overfunded position during the three and nine month periods ended September 30, 2021, and the same periods ended September 30, 2020, they were not impacted by market returns and the rate of return guarantee provided 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 consolidated balance sheet to the present value of the underlying 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 2020 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The higher accretion expense on the Nuclear Liabilities was due to the increase in the present value of the underlying obligation to reflect the passage of time.

Regulated – Hydroelectric Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2021**	**2020**	**2021**	**2020**
Electricity generation (TWh)	**6.9**	7.3	**21.4**	23.0
Revenue [1]	**370**	358	**1,185**	1,166
Fuel expense	**88**	90	**244**	251
Gross margin	**282**	268	**941**	915
Operations, maintenance and administration expenses	**87**	86	**262**	232
Property tax	**-**	-	**1**	1
Other losses	**-**	-	**1**	-
Earnings before interest, income taxes, depreciation and amortization	**195**	182	**677**	682
Depreciation and amortization expenses	**51**	53	**157**	160
Earnings before interest and income taxes	**144**	129	**520**	522

[1] During the three and nine month periods ended September 30, 2021, the Regulated – Hydroelectric Generation business segment revenue included incentive payments of $4 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2020 – $3 million and $5 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.

Earnings before interest and income taxes from the segment increased by $15 million for the three months ended September 30, 2021, compared to the same period in 2020. The increase was primarily due to the net impact of the Settlement Agreement related to OPG's response to the COVID-19 pandemic over 2020 and 2021, resulting in an increase of $11 million to EBIT for the Regulated – Hydroelectric Generation business segment.

Earnings before interest and income taxes from the segment for the nine months ended September 30, 2021 were comparable to the same period in 2020. This mainly reflected higher OM&A expenses from an increase in project expenses and the deferral of certain planned maintenance activities from 2020 in response to the onset of the COVID-19 pandemic, largely offset by higher revenue reflecting the above noted impact of the Settlement Agreement and the higher hydroelectric base regulated price effective January 1, 2021.

The Hydroelectric Availability for the generating stations within the Regulated – Hydroelectric Generation business segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	**2020**	**2021**	**2020**
Hydroelectric Availability *(%)* [1]	**81.9**	82.6	**88.4**	88.4

[1] Hydroelectric Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability decreased for the three months ended September 30, 2021, compared to the same period in 2020, primarily due to higher planned outage days from the deferral of certain planned maintenance and project activities from 2020 in response to the onset of the COVID-19 pandemic, partially offset by fewer unplanned outage days across the regulated hydroelectric fleet. Hydroelectric Availability for the nine months ended September 30, 2021 was comparable to the same period in 2020.

Contracted Hydroelectric and Other Generation Segment

(millions of dollars – except where noted)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2021	**2020**	**2021**	**2020**
Electricity Generation (TWh)	**0.9**	1.1	**3.6**	3.8
Revenue	**168**	158	**516**	496
Fuel expense	**16**	14	**39**	34
Gross margin	**152**	144	**477**	462
Operations, maintenance and administration expenses	**56**	57	**172**	167
Accretion on fixed asset removal liabilities	**2**	2	**5**	5
Property taxes	**5**	4	**13**	13
Income from investments subject to significant influence	**2**	-	**-**	(1)
Other losses (gains)	**-**	-	**3**	(3)
Earnings before interest, income taxes, depreciation and amortization	**87**	81	**284**	281
Depreciation and amortization expenses	**38**	36	**112**	120
Earnings before interest and income taxes	**49**	45	**172**	161

Earnings before interest and income taxes from the segment increased by $4 million for the three months ended September 30, 2021 compared to the same period in 2020. The increase was primarily due to higher revenue from Ontario-based thermal assets and US-based hydroelectric facilities, net of fuel expense, partially offset by lower revenue from the Lower Mattagami hydroelectric generating stations.

For the nine months ended September 30, 2021, earnings before interest and income taxes increased by $11 million primarily due to lower depreciation expense, reflecting updated estimates of fixed asset useful lives for the US-based hydroelectric facilities, and higher revenue from Ontario-based thermal and solar assets, partially offset by lower revenue and higher OM&A expenses from the Lower Mattagami hydroelectric generating stations.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Ontario-based assets within the Contracted Hydroelectric and Other Generation business segment were as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2021	**2020**	**2021**	**2020**
Hydroelectric Availability *(%)* [1,2]	**83.1**	82.1	**87.5**	85.1
Thermal EFOR *(%)* [2]	**0.8**	9.2	**1.6**	6.0

[1] Hydroelectric Availability reflects hydroelectric generating stations in Ontario. US hydroelectric generating operations are not reflected in these results.

[2] Hydroelectric Availability and Thermal EFOR are defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*.

The Hydroelectric Availability increased for the three and nine month periods ended September 30, 2021, compared to the same periods in 2020, primarily due to fewer unplanned outage days at the Lower Mattagami hydroelectric generating stations. For the three months ended September 30, 2021, the increase was partially offset by an increase in planned outage days from the deferral of certain planned maintenance activities from 2020 in response to the COVID-19 pandemic.

The Thermal EFOR decreased for the three and nine month periods ended September 30, 2021, compared to the same periods in 2020, primarily due to fewer unplanned outage days at the Lennox GS.

Contracted Gas Generation Segment

(millions of dollars – except where noted)	**Three Months Ended September 30** **2021**	**2020**	**Nine Months Ended September 30** **2021**	**2020**
Electricity Generation (TWh)	**1.5**	1.5	**3.1**	2.0
Revenue	**193**	153	**495**	270
Fuel expense	**74**	43	**153**	62
Gross margin	**119**	110	**342**	208
Operations, maintenance and administration expenses	**13**	9	**45**	25
Accretion on fixed asset removal liabilities	**-**	1	**1**	1
Property taxes	**-**	1	**1**	2
Income from investments subject to significant influence	**-**	-	**-**	(10)
Other losses	**1**	-	**1**	-
Earnings before interest, income taxes, depreciation and amortization	**105**	99	**294**	190
Depreciation and amortization expenses	**27**	28	**82**	53
Earnings before interest and income taxes	**78**	71	**212**	137

Earnings before interest and income taxes from the segment increased by $7 million for the three months ended September 30, 2021, compared to the same period in 2020, primarily due to higher gross margin reflecting a higher number of starts at the combined cycle plants during the third quarter of 2021.

Earnings before interest and income taxes from the segment increased by $75 million for the nine months ended September 30, 2021, compared to the same period in 2020, primarily due to the acquisition of the Napanee GS, Halton Hills GS and remaining 50 percent in the Portlands Energy Centre on April 29, 2020.

OPG's share of income from co-owning the Portlands Energy Centre prior to acquiring the remaining 50 percent interest on April 29, 2020 is reported as segment income from investments subject to significant influence in the comparative period.

The Thermal Availability for the assets within the Contracted Gas Generation business segment was as follows:

	Three Months Ended September 30 **2021**	**2020**	**Nine Months Ended September 30** **2021**	**2020**
Thermal Availability *(%)* [1]	**93.2**	94.4	**93.2**	94.4

[1] Thermal Availability is defined in the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*, and reflects the results of facilities for the periods they were wholly owned by the Company. In the first quarter of 2021, Thermal Availability replaced Thermal EFOR as the operating performance indicator for the Company's combined cycle plants reported in the Contracted Gas Generation business segment, consistent with the requirements under the facilities' respective ESAs or other long-term contracts. The measure is calculated on a three-year rolling average basis.

The Thermal Availability decreased during the three and nine month periods ended September 30, 2021, compared to the same periods in 2020, primarily due to the impact of planned outages at the combined cycle plants included in the segment.

LIQUIDITY AND CAPITAL RESOURCES

OPG maintains a range of funding sources to ensure sufficient liquidity and meet financing requirements, as discussed in the section, *Corporate Strategy, Core Business and Outlook* under the heading*, Financial Strength – Ensuring Availability of Cost Effective Funding*. These sources are used for multiple purposes including: to invest in plants and technologies, undertake major projects and business acquisitions, fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, make payments under the OPEB plans, fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, service and repay long-term debt, and provide general working capital.

Changes in cash and cash equivalents for the three and nine month periods ended September 30, 2021 and 2020 were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2021**	**2020**	**2021**	**2020**
Cash, cash equivalents and restricted cash, beginning of period	**857**	971	**725**	498
Cash flow provided by operating activities	**889**	1,007	**1,965**	2,547
Cash flow used in investing activities	**(541)**	(421)	**(1,240)**	(4,053)
Cash flow (used in) provided by financing activities	**(303)**	(733)	**(547)**	1,835
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**1**	4	**-**	1
Net increase (decrease) in cash, cash equivalents and restricted cash	**46**	(143)	**178**	330
Cash, cash equivalents and restricted cash, end of period	**903**	828	**903**	828

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Cash Flow from Operations*.

Investing Activities

Cash flow used in investing activities increased by $120 million and decreased by $2,813 million during the three and nine month periods ended September 30, 2021, respectively, compared to the same periods in 2020. The increase for the three months ended September 30, 2021, compared to the same period in 2020, was primarily due to increased capital expenditures on the Darlington Refurbishment project, the Little Long Dam Safety project, the redevelopment of the Calabogie GS, and hydroelectric asset overhaul programs in 2021. The decrease for the nine months ended September 30, 2021, compared to the same period in 2020, was primarily due to the acquisition of a portfolio of combined cycle plants in April 2020.

Financing Activities

Cash flow used in financing activities decreased by $430 million for the three months ended September 30, 2021, compared to the same period in 2020, primarily due to higher repayments of short-term and long-term debt.

Cash flow provided by financing activities decreased by $2,382 million for the nine months ended September 30, 2021, compared to the same period in 2020. The decrease was primarily due to higher borrowing to support project work and acquisition activity in 2020.

As at September 30, 2021, the Company had the following committed credit facilities:

(millions of dollars)		Amount
Bank facilities:		
Corporate [1]		**1,000**
Corporate [1]	US Dollars	**750**
Lower Mattagami Energy Limited Partnership [2]		**400**
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**25**
OEFC facility [3]		**300**

1 These credit facilities contain a sustainability-linked feature that allows reduced pricing if the Company meets certain sustainability targets. In the second quarter of 2021, OPG extended the $1 billion credit facility to have a maturity date of May 2026.
2 In the third quarter of 2021, the facility was extended with a maturity date of August 2026. A letter of credit of $55 million was outstanding under this facility as at September 30, 2021.
3 Represents amounts available under the facility, net of debt issuances.

Short-term debt, letters of credit and guarantees were as follows:

(millions of dollars)	As At September 30 2021	December 31 2020
Lower Mattagami Energy Limited Partnership	**70**	131
Corporate commercial paper	**45**	919
Total short-term debt	**115**	1,050
Letters of credit	**565**	607
Guarantees	**4**	4

As of September 30, 2021, a total of $565 million of Letters of Credit had been issued. This included $428 million for the supplementary pension plans, $15 million for OPG Eagle Creek Holdings LLC and its subsidiaries, $55 million for Lower Mattagami Energy Limited Partnership, $44 million for general corporate purposes, $16 million for UMH Energy Partnership, $6 million for Atura Power and $1 million for PSS Generating Station Limited Partnership.

Long-term debt balances as of September 30, 2021 and December 31, 2020 were as follows: [1]

(millions of dollars)	As At September 30 2021	December 31 2020
Medium Term Notes payable	**4,350**	3,850
Notes payable to the OEFC	**2,750**	2,875
Project financing	**2,632**	2,591
Other	**25**	25
	9,757	9,341

1 Excludes the impact of fair value premium or discount and unamortized bond issuance fees.

Share Capital

As at September 30, 2021, and December 31, 2020, 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.

As at September 30, 2021, and December 31, 2020, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

BALANCE SHEET HIGHLIGHTS

Highlights of OPG's interim consolidated financial position are noted below:

(millions of dollars)	As At September 30 2021	 December 31 2020
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)* The increase was primarily due to earnings recognized on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities from the Nuclear Segregated Funds.	**19,666**	19,096
Short-term debt *(current and non-current portions)* The decrease was mainly due to net repayments made under the Company's corporate commercial paper program.	**115**	1,050
Long-term debt *(current and non-current portions)* The increase was mainly due to the issuance of $500 million of bonds under the Medium Term Note program in February 2021 and the issuance of $375 million of green bonds by Lower Mattagami Energy Limited Partnership in May 2021, net of debt repayments.	**9,730**	9,332
Fixed asset removal and nuclear waste management liabilities The increase was primarily a result of accretion expense, partially offset by expenditures on fixed asset removal and nuclear waste management activities.	**23,543**	22,947

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 consolidated financial statements or are recorded in the Company's 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, 2020. A discussion of recent accounting pronouncements is included in Note 2 of OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2021. OPG's critical accounting policies are consistent with those noted in OPG's 2020 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2020 annual MD&A.

Risks to Achieving Operational Excellence

OPG is exposed to a range of operational risks associated with its existing assets that could adversely impact generation output, safety performance and operating results. The operational risks of a station include aspects such as occupational safety, resourcing, equipment reliability, human performance, climate change, regulatory requirements and technology.

COVID-19 Pandemic

The Company continues to monitor developments relating to the COVID-19 pandemic and mitigate associated risks to the health and safety of its workers, operations and projects. While the number of newly reported COVID-19 cases in Ontario has declined from the peak earlier in 2021 and significant progress has been made in abating the pandemic with increased vaccination coverage, uncertainties remain regarding the pandemic's future course and impact. Key focus areas include transmission rates during the fall and winter weather in communities where OPG operates, vaccination rates of OPG employees and contractors, as well as the potential impact of new variants of the virus. Although OPG's core business has not been significantly affected by the pandemic, the Company's risks related to the COVID-19 pandemic include the health and safety of employees, the disruption of supply chains, the viability of contractors, vendors and project partners, and impacts to the wholesale electricity prices in US markets.

In October 2021, OPG implemented a company-wide vaccination standard for all OPG employees and contractors. OPG is committed to creating a safe workplace and expects that all employees and contractors be fully vaccinated against COVID-19. Proof of vaccination status is required to manage, change and/or lift restrictions currently in place while complying with public health and legal requirements, and to inform workforce planning and management. All OPG employees and contractors who do not provide confirmation of vaccination status are required to adhere to additional safety precautions, including continued screening and regular testing requirements.

OPG will continue to monitor and, as necessary, adjust strategies to minimize the impact of the pandemic on the organization, including making enhancements to business continuity plans based on experience to date.

The cumulative impact of incremental operating costs and lost revenues related to the pandemic has not been material to the Company's financial results since the pandemic's initial onset in the first quarter of 2020.

Additional details are included in the section, *Corporate Strategy, Core Business and Outlook* under the heading, *Electricity Generation Production and Reliability*.

Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as changes in market prices of electricity, renewal of energy supply contracts, and differences in realized economic value from acquisitions and other investments.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, and treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to energy market transactions as at September 30, 2021 was $572 million, including $545 million with the IESO. OPG continues to consider overall credit risk exposure relating to electricity sales to be low, as the majority of sales are through the IESO-administered market in Ontario.

Commodity Markets

Changes in the market prices 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 electricity generation and supply mix and, as such, are subject to change as these forecasts are updated.

	2021 [1]	2022	2023
Estimated fuel requirements hedged [2]	**76%**	**81**%	**77**%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2021 and forecast for the remainder of the year.

[2] Represents the approximate portion of MWh of expected electricity generation (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the price of fuel is fixed, or for which the Company has entered into contractual arrangements to secure the price of fuel or secure the recovery of fuel costs. In the case of regulated and contracted hydroelectric electricity generation in Ontario, the fuel price 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.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the 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. 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 one of several wholly owned government business enterprises 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.

Related party transactions are summarized below:

	Three Months Ended September 30			
	2021		2020	
(millions of dollars)	Income	Expense	Income	Expense
Hydro One				
Electricity sales	**4**	**-**	1	-
Services	**-**	**1**	-	2
Dividends	**1**	**-**	2	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**2**	-	242
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**7**	-	245
Hydroelectric gross revenue charge	**-**	**25**	-	26
OEFC				
Hydroelectric gross revenue charge	**-**	**57**	-	62
Interest expense on long-term notes	**-**	**26**	-	29
Income taxes	**-**	**153**	-	137
Property taxes	**-**	**3**	-	3
IESO				
Electricity-related revenue	**1,767**	**-**	1,661	-
Fair Hydro Trust				
Interest income	**9**	**-**	9	-
	1,781	**274**	1,673	746

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2021 and December 31, 2020, the Nuclear Segregated Funds were reported net of amounts due to the Province of $7,665 million and $6,714 million, respectively.

	Nine Months Ended September 30			
	2021		2020	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**8**	**-**	4	-
Services	**-**	**5**	-	6
Dividends	**4**	**-**	5	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**408**	11	-
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**543**	56	-
Hydroelectric gross revenue charge	**-**	**78**	-	81
OEFC				
Hydroelectric gross revenue charge	**-**	**143**	-	153
Interest expense on long-term notes	**-**	**78**	-	92
Income taxes	**-**	**388**	-	390
Property taxes	**-**	**9**	-	9
IESO				
Electricity-related revenue	**4,883**	**-**	4,757	-
Fair Hydro Trust				
Interest income	**25**	**-**	25	-
	4,920	**1,652**	4,858	731

[1] The Nuclear Segregated Funds are reported on OPG's consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2021 and December 31, 2020, the Nuclear Segregated Funds were reported net of amounts due to the Province of $7,665 million and $6,714 million, respectively.

Balances between OPG and its related parties are summarized below:

	As At	
(millions of dollars)	**September 30 2021**	**December 31 2020**
Receivables from related parties		
Hydro One	**4**	1
IESO – Electricity related receivables	**545**	487
Fair Hydro Trust	**12**	4
OEFC	**11**	-
Province of Ontario	**6**	-
Loan receivable		
Fair Hydro Trust	**911**	913
Equity securities		
Hydro One shares	**160**	172
Accounts payable, accrued charges and other payables		
Hydro One	**-**	2
OEFC	**69**	88
Province of Ontario	**5**	7
IESO – Electricity related payables	**2**	6
Long-term debt (including current portion)		
Notes payable to OEFC	**2,750**	2,875

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, 2021, the Nuclear Segregated Funds held $1,767 million of Province of Ontario bonds (December 31, 2020 – $1,601 million) and $8 million of Province of Ontario treasury bills (December 31, 2020 – $10 million). As of September 30, 2021, the registered pension fund held $53 million of Province of Ontario bonds (December 31, 2020 − $50 million) and $5 million of Province of Ontario treasury bills (December 31, 2020 – nil). These 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.

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 (ICOFR) and for its Disclosure Controls and Procedures (DC&P). 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 financial statements.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected quarterly financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited annual consolidated financial statements, and has been prepared in accordance with US GAAP.

(millions of dollars – except where noted) *(unaudited)*	**September 30 2021**	**June 30 2021**	**March 31 2021**	**December 31 2020**
Electricity generation (*TWh*)	**21.0**	19.2	19.1	19.2
Revenue	**1,712**	1,804	1,691	1,782
Net income	**430**	522	295	211
Less: Net income attributable to non-controlling interest	**4**	4	5	3
Net income attributable to the Shareholder	**426**	518	290	208
Earnings per share, attributable to the Shareholder *(dollars)*	**$1.55**	$1.89	$1.06	$0.76

(millions of dollars – except where noted) *(unaudited)*	**September 30 2020**	**June 30 2020**	**March 31 2020**	**December 31 2019**
Electricity generation (*TWh*)	21.3	20.9	20.7	19.4
Revenue	1,889	1,849	1,720	1,522
Net income	390	462	313	247
Less: Net income attribute to the non-controlling interest	4	4	4	4
Net income attributable to the Shareholder	386	458	309	243
Earnings per share, attributable to the Shareholder *(dollars)*	$1.41	$1.67	$1.13	$0.88

KEY OPERATING PERFORMANCE INDICATORS AND NON-GAAP FINANCIAL MEASURES

Key Operating Performance Measures

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate business imperatives include measures of production reliability, cost effectiveness, environmental performance and safety performance. Certain of the measures used vary depending on the generating technology.

Nuclear Unit Capability Factor

The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. An outage day represents a single unit being offline or derated for an amount of time equivalent to one day. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. As at September 30, 2021, the Darlington GS had three units in service and the Pickering GS had six units in service.

Hydroelectric Availability

Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, weighted by unit capacity.

Thermal Equivalent Forced Outage Rate

Equivalent forced outage rate is an index of the reliability of a generating unit at OPG's wholly-owned thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Thermal Availability

Thermal Availability represents the percentage of time a generating unit at Atura Power's combined cycle gas turbine facilities is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, averaged by the number of facilities owned and operated through Atura Power. The measure is calculated on a three-year rolling average basis.

Other Key Indicators

In addition to production reliability, cost effectiveness and financial performance indicators, OPG has identified certain environmental and safety performance measures. As applicable, these measures are discussed in the section, *Environmental, Social, Governance and Sustainability*.

Non-GAAP Financial Performance Measures

In addition to net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in this 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) Enterprise Total Generating Cost per MWh is used to measure the overall cost performance of OPG's generating operations in Ontario. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project, generation development and other major projects, and business development activities, US operations, the impact of regulatory accounts, 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, generation development and other major projects and US operations) incurred during the period, divided by total electricity generation from OPG-operated generating stations in Ontario plus electricity generation forgone due to SBG conditions in Ontario during the period.

Enterprise TGC per MWh is calculated as follows for the three and nine month periods ended September 30, 2021 and September 30, 2020:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2021**	**2020**	**2021**	**2020**
Enterprise TGC				
Total OM&A expenses	**555**	716	**2,067**	2,108
Total fuel expense	**241**	225	**628**	577
Total capital expenditures	**556**	410	**1,462**	1,244
Less: Darlington Refurbishment capital and OM&A costs	**(219)**	(149)	**(632)**	(605)
Less: Capital and OM&A costs for generation development and other major projects and for business development activities	**(157)**	(58)	**(352)**	(115)
Add / (Less): OM&A and fuel expenses deferred in (refundable through) regulatory accounts	**199**	(23)	**279**	(97)
Less: Nuclear fuel expense for non OPG-operated stations	**(22)**	(15)	**(63)**	(45)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**6**	13	**23**	39
Less: OM&A expenses ancillary to electricity generation business	**(6)**	(6)	**(14)**	(15)
Less: OM&A expenses and capital expenditures related to US operations	**(23)**	(27)	**(70)**	(82)
Other adjustments	**(7)**	(8)	**(15)**	(14)
	1,123	1,078	**3,313**	2,995
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**21.0**	21.3	**59.3**	62.9
Adjust for electricity generation forgone due to SBG conditions, OPG's share of electricity generation from co-owned facilities and US operations	**(0.1)**	0.1	**0.1**	1.3
	20.9	21.4	**59.4**	64.2
Enterprise TGC per MWh ***($/MWh)*** [1]	**53.62**	50.36	**55.75**	46.60

[1] Amounts may not calculate due to rounding.

(2) Earnings before interest, income taxes, depreciation and amortization is defined as net income before net interest expense, income tax expense and depreciation and amortization expenses.

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

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2021

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars – except where noted)	Three Months Ended September 30 2021	2020	Nine Months Ended September 30 2021	2020
Revenue	**1,712**	1,889	**5,207**	5,458
Fuel expense	**241**	225	**628**	577
Gross margin	**1,471**	1,664	**4,579**	4,881
Operations, maintenance and administration expenses	**555**	716	**2,067**	2,108
Depreciation and amortization expenses	**277**	337	**832**	985
Accretion on fixed asset removal and nuclear waste management liabilities	**274**	263	**818**	791
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(243)**	(234)	**(722)**	(693)
Property taxes	**13**	12	**37**	37
Income from investments subject to significant influence	**2**	-	**-**	(11)
	878	1,094	**3,032**	3,217
Income before other gains, interest and income taxes	**593**	570	**1,547**	1,664
Other losses (gains) *(Note 12)*	**32**	(7)	**(87)**	(16)
Income before interest and income taxes	**561**	577	**1,634**	1,680
Net interest expense *(Note 6)*	**53**	61	**167**	190
Income before income taxes	**508**	516	**1,467**	1,490
Income tax expense	**78**	126	**220**	325
Net income	**430**	390	**1,247**	1,165
Net income attributable to the Shareholder	**426**	386	**1,234**	1,153
Net income attributable to non-controlling interest	**4**	4	**13**	12
Basic and diluted earnings per share *(dollars) (Note 14)*	**1.55**	1.41	**4.49**	4.20

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2021**	**2020**	**2021**	**2020**
Net income	**430**	390	**1,247**	1,165
Other comprehensive income (loss), net of income taxes *(Note 9)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**5**	3	**13**	8
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**3**	2	**9**	9
Net gain on derivatives designated as cash flow hedges [3]	**-**	-	**-**	2
Currency translation adjustment	**44**	(34)	**1**	41
Other comprehensive income (loss) for the period	**52**	(29)	**23**	60
Comprehensive income	**482**	361	**1,270**	1,225
Comprehensive income attributable to the Shareholder	**478**	357	**1,257**	1,213
Comprehensive income attributable to non-controlling interest	**4**	4	**13**	12

1 Net of income tax expense of $1 million and nil for the three months ended September 30, 2021 and 2020, respectively. Net of income tax expense of $4 million and $2 million for the nine months ended September 30, 2021 and 2020, respectively.
2 Net of income tax expense of nil and $1 million for the three months ended September 30, 2021 and 2020, respectively. Net of income tax expense of $1 million and $2 million for the nine months ended September 30, 2021 and 2020, respectively.
3 Net of income tax expense of $1 million for the nine months ended September 30, 2020.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	Nine Months Ended September 30 2021	2020
Operating activities		
Net income	**1,247**	1,165
Adjust for non-cash items:		
Depreciation and amortization expenses	**832**	985
Accretion on fixed asset removal and nuclear waste management liabilities	**818**	791
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(722)**	(693)
Pension and other post-employment benefit costs *(Note 10)*	**344**	333
Deferred income tax expense	**26**	66
Regulatory assets and regulatory liabilities	**(183)**	(60)
Other gains	**(83)**	(11)
Other	**(2)**	(11)
Expenditures on fixed asset removal and nuclear waste management	**(335)**	(313)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**148**	96
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(235)**	(220)
Distributions received from investments subject to significant influence	**-**	13
Net changes to other long-term assets and long-term liabilities	**48**	65
Net changes to non-cash working capital balances *(Note 17)*	**62**	341
Cash flow provided by operating activities	**1,965**	2,547
Investing activities		
Investment in property, plant and equipment and intangible assets	**(1,460)**	(1,239)
Proceeds from settlement related to acquired natural gas-fired assets *(Note 18)*	**220**	-
Acquisition of natural gas-fired assets, net of cash acquired	**-**	(2,814)
Cash flow used in investing activities	**(1,240)**	(4,053)
Financing activities		
Net (repayment) issuance of short-term debt *(Note 7)*	**(937)**	890
Net proceeds from issuance of long-term debt *(Note 6)*	**868**	1,595
Repayment of long-term debt *(Note 6)*	**(464)**	(635)
Distribution to non-controlling interest	**(14)**	(15)
Cash flow (used in) provided by financing activities	**(547)**	1,835
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**-**	1
Net increase in cash, cash equivalents and restricted cash	**178**	330
Cash, cash equivalents and restricted cash, beginning of period	**725**	498
Cash, cash equivalents and restricted cash, end of period	**903**	828

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As At *(millions of dollars)*	**September 30 2021**	**December 31 2020**
Assets		
Current assets		
Cash, cash equivalents and restricted cash *(Note 4)*	**903**	725
Equity securities	**229**	172
Receivables from related parties	**578**	492
Nuclear fixed asset removal and nuclear waste management funds	**40**	46
Fuel inventory	**254**	236
Materials and supplies	**93**	92
Regulatory assets *(Note 5)*	**349**	533
Prepaid expenses	**161**	145
Other current assets	**136**	114
	2,743	2,555
Property, plant and equipment	**41,764**	40,555
Less: accumulated depreciation	**11,448**	10,745
	30,316	29,810
Intangible assets	**820**	783
Less: accumulated amortization	**357**	312
	463	471
Goodwill	**162**	162
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**19,626**	19,050
Loan receivable from related party	**911**	913
Long-term materials and supplies	**433**	404
Regulatory assets *(Note 5)*	**8,546**	8,571
Investments subject to significant influence	**41**	37
Other long-term assets	**90**	100
	29,647	29,075
	63,331	62,073

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As At *(millions of dollars)*	**September 30 2021**	**December 31 2020**
Liabilities		
Current liabilities		
Accounts payable, accrued charges and other payables	**1,387**	1,257
Short-term debt *(Note 7)*	**115**	1,050
Long-term debt due within one year *(Note 6)*	**209**	439
Regulatory liabilities *(Note 5)*	**258**	266
	1,969	3,012
Long-term debt *(Note 6)*	**9,521**	8,893
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 8)*	**23,543**	22,947
Pension liabilities	**4,805**	5,005
Other post-employment benefit liabilities	**3,463**	3,406
Long-term accounts payable and accrued charges	**356**	269
Deferred revenue	**384**	391
Deferred income taxes	**1,608**	1,379
Regulatory liabilities *(Note 5)*	**895**	1,239
	35,054	34,636
Equity		
Common shares *(Note 13)*	**5,126**	5,126
Class A shares *(Note 13)*	**787**	787
Contributed surplus	**35**	36
Retained earnings	**11,013**	9,779
Accumulated other comprehensive loss *(Note 9)*	**(351)**	(374)
Equity attributable to the Shareholder	**16,610**	15,354
Equity attributable to non-controlling interest	**177**	178
Total equity	**16,787**	15,532
	63,331	62,073

Commitments and Contingencies *(Notes 6, 7, 10 and 15)*

See accompanying notes to the interim consolidated financial statements

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

Nine Months Ended September 30 *(millions of dollars)*	**2021**	**2020**
Common shares *(Note 13)*	**5,126**	5,126
Class A shares *(Note 13)*	**787**	787
Contributed surplus		
Balance at beginning of period	**36**	39
Reclassification to income of amounts related to gain on deconsolidation of Fair Hydro Trust	**(1)**	-
Balance at end of period	**35**	39
Retained earnings		
Balance at beginning of period	**9,779**	8,418
Net income attributable to the Shareholder	**1,234**	1,153
Balance at end of period	**11,013**	9,571
Accumulated other comprehensive loss, net of income taxes *(Note 9)*		
Balance at beginning of period	**(374)**	(277)
Other comprehensive income	**23**	60
Balance at end of period	**(351)**	(217)
Equity attributable to the Shareholder	**16,610**	15,306
Equity attributable to non-controlling interest		
Balance at beginning of period	**178**	182
Income attributable to non-controlling interest	**13**	12
Distribution to non-controlling interest	**(14)**	(15)
Balance at end of period	**177**	179
Total equity	**16,787**	15,485

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine month periods ended September 30, 2021 and 2020 include the accounts of Ontario Power Generation Inc. (OPG or 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 (the Province or the Shareholder). 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, 2020.

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 also has 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 prepared in accordance with 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 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; or
- 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 2020 comparative amounts have been reclassified from consolidated financial statements previously presented to conform to the 2021 interim consolidated financial statement presentation.

Seasonal Variations

OPG's quarterly electricity generation from the Regulated – Hydroelectric Generation, Contracted Hydroelectric and Other Generation, and Contracted Gas Generation business segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by 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. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands.

OPG's quarterly electricity generation from hydroelectric facilities is impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the second quarter as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric Generation business segment is mitigated by regulatory variance and deferral accounts (regulatory accounts) authorized by the Ontario Energy Board (OEB).

The financial impact of variability in electricity generation from the Contracted Hydroelectric and Other Generation business segment and the Contracted Gas Generation business segment is mitigated by the terms of the applicable Energy Supply Agreements with the Independent Electricity System Operator (IESO) and other long-term contracts for the contracted generating facilities in Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

The accounting policies followed in the presentation of these interim consolidated financial statements are consistent with those of the previous fiscal year.

Recent Accounting Pronouncements Not Yet Adopted

Changes to Credit Losses on Financial Instruments

In June 2016, the Financial Accounting Standards Board (FASB) issued ASU 2016-13, *Measurement of Credit Losses on Financial Instruments* (ASU 2016-13), an update to Topic 326, *Financial Instruments – Credit Losses*. ASU 2016-13 requires financial assets measured at amortized cost to be presented at the net amount expected to be collected, through an allowance for credit losses to be deducted from the amortized cost basis of the asset. Available-for-sale debt securities will also require the use of an allowance to record estimated credit losses. In November 2019, the FASB issued ASU 2019-11, *Codification Improvements to Topic 326, Financial Instruments – Credit Losses,* which clarified that ASU 2016-13 is effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years, with early adoption permitted. The revised guidance will be applied through a cumulative catch-up adjustment to retained earnings in the period of adoption. OPG continues to assess the impact of this update to its consolidated financial statements.

3. AGREEMENT TO ACQUIRE US HYDROELECTRIC PLANT

In February 2021, OPG entered into an agreement to acquire, through OPG Eagle Creek Holdings LLC, a 48 megawatt hydroelectric facility in the US for approximately US$90 million, subject to customary working capital and other adjustments. The closing of the transaction is subject to Federal Energy Regulatory Commission and other customary approvals.

4. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

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

As At *(millions of dollars)*	**September 30 2021**	**December 31 2020**
Cash and cash equivalents	**893**	717
Restricted cash	**10**	8
Total cash, cash equivalents and restricted cash	**903**	725

Restricted cash is held primarily for prescribed purposes, including debt service, general collateral purposes and other contractual arrangements.

5. REGULATORY ASSETS AND REGULATORY LIABILITIES

The regulatory assets and regulatory liabilities consist of the following:

As At *(millions of dollars)*	**September 30 2021**	**December 31 2020**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**945**	921
Rate Smoothing Deferral Account	**525**	508
Hydroelectric Surplus Baseload Generation Variance Account	**432**	481
Bruce Lease Net Revenues Variance Account	**148**	166
Pension and OPEB Cost Variance Account	**138**	350
Other variance and deferral accounts [1]	**116**	42
	2,304	2,468
Pension and OPEB Regulatory Asset *(Note 10)*	**5,001**	5,199
Deferred Income Taxes	**1,590**	1,437
Total regulatory assets	**8,895**	9,104
Less: current portion	**349**	533
Non-current regulatory assets	**8,546**	8,571
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Pension & OPEB Cash Payment Variance Account	**490**	481
Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account	**226**	416
Hydroelectric Water Conditions Variance Account	**158**	240
Capacity Refurbishment Variance Account	**47**	161
Other variance and deferral accounts [2]	**185**	207
Other	**47**	-
Total regulatory liabilities	**1,153**	1,505
Less: current portion	**258**	266
Non-current regulatory liabilities	**895**	1,239

[1] Represents amounts for the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Variance Account, the Fitness for Duty Deferral Account, the Pickering Closure Costs Deferral Account and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

[2] Represents amounts for the Ancillary Services Net Revenue Variance Account, the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the SR&ED ITC Variance Account, the Pension & OPEB Forecast Accrual Versus Actual Cash Payment Differential Carrying Charges Variance Account and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account.

In December 2020, OPG filed a five-year application with the OEB for new base regulated prices for production from the Company's nuclear facilities, with a proposed effective date of January 1, 2022. Additionally, the application included a request for new rate riders to recover or repay the December 31, 2019 balances in most of the Company's regulatory accounts, less amounts previously approved for recovery or repayment through rate riders in effect to December 31, 2021, as well as the continuation of all applicable existing deferral and variance accounts. In July 2021, OPG and the intervenors in OPG's application reached a proposed settlement on most of the issues in the application (Settlement Agreement). The Settlement Agreement was submitted for approval to the OEB on July 16, 2021. An oral hearing on the unsettled issues was held between August 4, 2021 and August 6, 2021. On August 6, 2021, the OEB issued an oral decision approving the Settlement Agreement. Final regulated prices to be approved by the OEB will reflect the Settlement Agreement and the OEB's pending decision on the unsettled issues. Pursuant to the Settlement Agreement, the new regulated prices will be effective January 1, 2022.

Subject to the OEB's decision on an unsettled issue relating to the in-service capital additions for the Heavy Water Storage and Drum Handling Facility and associated regulatory account balances, the Settlement Agreement includes recovery of a net total of $702 million comprising amounts recorded in the regulatory accounts as at December 31, 2019 and associated income tax impacts, including for the Pension & OPEB Cash Versus Accrual Differential Deferral Account, without adjustments. These balances will be recovered or repaid effective January 1, 2022 over periods ranging from three to five years. Additionally, the Settlement Agreement defers the clearance of a portion equal to $40 million of amounts recorded as recoverable from customers in the Hydroelectric Surplus Baseload Generation Variance Account as at December 31, 2019 to a future proceeding. The income tax impacts included for recovery were previously recorded as part of the regulatory asset for deferred income taxes.

Additionally, as part of the Settlement Agreement, OPG will credit ratepayers with $47 million related to the difference between the Company's net favourable electricity revenue impact and incremental operations, maintenance and administration expenses arising from the pandemic response over 2020 and 2021. The Company recorded a corresponding increase in regulatory liabilities and a reduction in net income related to these impacts during the third quarter of 2021. Upon the OEB's approval of the Settlement Agreement, OPG ceased being subject to the deferral account for recording lost revenues and incremental costs related to the COVID-19 pandemic that was established by the OEB in March 2020.

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consist of the following:

As At *(millions of dollars)*	**September 30 2021**	**December 31 2020**
Medium Term Note Program senior notes	**4,350**	3,850
Senior notes payable to the Ontario Electricity Financial Corporation	**2,750**	2,875
UMH Energy Partnership senior notes	**171**	172
PSS Generating Station Limited Partnership senior notes	**245**	245
Lower Mattagami Energy Limited Partnership senior notes	**1,745**	1,595
Brighton Beach Power Limited Partnership senior notes	**-**	86
OPG Eagle Creek Holdings LLC and subsidiaries senior notes	**471**	493
Other	**25**	25
	9,757	9,341
Plus: net fair value premium	**13**	24
Less: unamortized bond issuance fees	**(40)**	(33)
Less: amounts due within one year	**(209)**	(439)
Long-term debt	**9,521**	8,893

OPG repaid long-term debt of $125 million to the Ontario Electricity Financial Corporation (OEFC) during the nine months ended September 30, 2021.

On February 2, 2021, OPG issued $500 million of bonds under the Company's Medium Term Note Program, maturing in February 2051 with a coupon interest rate of 2.95 percent.

On May 14, 2021, OPG's wholly-owned Lower Mattagami Energy Limited Partnership (LME) completed a private placement bond offering with the issuance of $375 million of green bonds, maturing in May 2031 with a coupon interest rate of 2.43 percent. On May 18, 2021, LME repaid senior notes totalling $225 million that had matured.

On June 30, 2021, OPG repaid the remaining $81 million of senior notes payable by Brighton Beach Power Limited Partnership.

Net Interest Expense

The following table summarizes the net interest expense:

(millions of dollars)	Three Months Ended September 30 2021	2020	Nine Months Ended September 30 2021	2020
Interest on long-term debt	**93**	93	**278**	277
Interest on short-term debt	**1**	4	**6**	13
Interest income	**(10)**	(11)	**(29)**	(35)
Interest capitalized to property, plant and equipment and intangible assets	**(22)**	(12)	**(57)**	(97)
Interest related to regulatory assets and regulatory liabilities [1]	**(9)**	(13)	**(31)**	32
Net interest expense	**53**	61	**167**	190

[1] Includes interest to recognize the cost of financing regulatory account balances as authorized by the OEB, and interest costs deferred in certain regulatory accounts.

7. SHORT-TERM DEBT

Committed credit facilities and maturity dates as at September 30, 2021 were as follows:

(millions of dollars)		Amount	Maturity
Bank facilities:			
Corporate		**1,000**	May 2026 [1]
Corporate	US Dollars	**750**	November 2021 [1, 2]
Lower Mattagami Energy Limited Partnership		**400**	August 2026 [3]
OPG Eagle Creek Holdings LLC and subsidiaries	US Dollars	**25**	August 2022 and October 2028 [4]
OEFC facility [5]		**300**	December 2021

[1] These credit facilities contain a sustainability-linked feature that allows reduced pricing if the Company meets certain sustainability targets. In the second quarter of 2021, OPG extended the $1 billion credit facility to have a maturity date of May 2026.
[2] The facility has a one-year extension option beyond the maturity date of November 2021.
[3] In the third quarter of 2021, the facility was extended with a maturity date of August 2026. A letter of credit of $55 million was outstanding under this facility as at September 30, 2021 and December 31, 2020.
[4] Of the total credit facility, $5 million matures in August 2022 and $20 million matures in October 2028.
[5] Represents amounts available under the facility, net of debt issuances.

Short-term debt consist of the following:

As At *(millions of dollars)*	September 30 2021	December 31 2020
Lower Mattagami Energy Limited Partnership	**70**	131
Corporate commercial paper	**45**	919
Total short-term debt	**115**	1,050

As of September 30, 2021, a total of $565 million of Letters of Credit had been issued (December 31, 2020 – $607 million). As of September 30, 2021, this included $428 million for the supplementary pension plans, $15 million for OPG Eagle Creek Holdings LLC and its subsidiaries, $55 million for LME, $44 million for general corporate purposes, $16 million for UMH Energy Partnership, $6 million for Atura Power, and $1 million for PSS Generating Station Limited Partnership.

For the nine months ended September 30, 2021, net repayment of short-term debt totalled $937 million (September 30, 2020 – net issuance of $890 million), which was comprised of issuances of $3,004 million (September 30, 2020 – $7,214 million) and repayments of $3,941 million (September 30, 2020 – $6,324 million).

The weighted average interest rate on the short-term debt as of September 30, 2021 is 0.22 percent (December 31, 2020 – 0.29 percent).

8. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

Liabilities for fixed asset removal and nuclear waste management on a present value basis consist of the following:

As At *(millions of dollars)*	**September 30 2021**	**December 31 2020**
Liability for used nuclear fuel management	**13,991**	13,589
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**9,259**	9,032
Liability for non-nuclear fixed asset removal	**293**	326
Fixed asset removal and nuclear waste management liabilities	**23,543**	22,947

9. ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Nine Months Ended September 30, 2021			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
AOCL, beginning of period	**(18)**	**(296)**	**(60)**	**(374)**
Amounts reclassified from AOCL	**9**	**13**	**-**	**22**
Translation of foreign operations	**-**	**-**	**1**	**1**
Other comprehensive income for the period	**9**	**13**	**1**	**23**
AOCL, end of period	**(9)**	**(283)**	**(59)**	**(351)**

	Nine Months Ended September 30, 2020			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
AOCL, beginning of period	(33)	(213)	(31)	(277)
Net gain on cash flow hedges	2	-	-	2
Amounts reclassified from AOCL	9	8	-	17
Translation of foreign operations	-	-	41	41
Other comprehensive income for the period	11	8	41	60
AOCL, end of period	(22)	(205)	10	(217)

The significant amounts reclassified out of each component of AOCL, net of income taxes, were as follows:

(millions of dollars)	Amount Reclassified from AOCL Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021	Statement of Income Line Item
Amortization of losses from cash flow hedges			
Losses	**3**	**10**	Net interest expense
Income tax recovery	**-**	**(1)**	Income tax expense
	3	**9**	
Amortization of amounts related to pension and OPEB			
Actuarial losses, net of past service credits	**6**	**17**	See (1) below
Income tax recovery	**(1)**	**(4)**	Income tax expense
	5	**13**	
Total reclassifications for the period	**8**	**22**	

(millions of dollars)	Amount Reclassified from AOCL Three Months Ended September 30, 2020	Nine Months Ended September 30, 2020	Statement of Income Line Item
Amortization of losses from cash flow hedges			
Losses	3	11	Net interest expense
Income tax recovery	(1)	(2)	Income tax expense
	2	9	
Amortization of amounts related to pension and OPEB			
Actuarial losses, net of past service credits	3	10	See (1) below
Income tax recovery	-	(2)	Income tax expense
	3	8	
Total reclassifications for the period	5	17	

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

Existing pre-tax net losses for derivatives of $11 million deferred in AOCL as at September 30, 2021 are expected to be reclassified to net income within the next 12 months.

10. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and other post-employment benefit (OPEB) costs for the three months ended September 30, 2021 and 2020 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**
Components of cost recognized for the period						
Current service costs	**92**	86	**3**	3	**23**	23
Interest on projected benefit obligation	**106**	132	**2**	2	**21**	23
Expected return on plan assets, net of expenses	**(216)**	(218)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**69**	41	**2**	1	**1**	-
Costs recognized [2]	**51**	41	**7**	6	**45**	46

[1] The net impact of amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended September 30, 2021 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $66 million (three months ended September 30, 2020 – $39 million).

[2] Pension and OPEB costs for the three months ended September 30, 2021 exclude the net addition of costs of $12 million resulting from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended September 30, 2020 – net addition of costs of $18 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2021 and 2020 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2021**	**2020**	**2021**	**2020**	**2021**	**2020**
Components of cost recognized for the period						
Current service costs	**276**	255	**7**	7	**71**	67
Interest on projected benefit obligation	**317**	397	**7**	8	**60**	72
Expected return on plan assets, net of expenses	**(646)**	(653)	**-**	-	**-**	-
Amortization of past service credits [1]	**-**	-	**-**	-	**(1)**	(1)
Amortization of net actuarial loss [1]	**205**	122	**7**	5	**4**	-
Costs recognized [2]	**152**	121	**21**	20	**134**	138

[1] The amortization of net actuarial loss and the amortization of past service credits are recognized as an increase (decrease) to other comprehensive income. The net increase in other comprehensive income for the nine months ended September 30, 2021 was partially offset by a net decrease in the Pension and OPEB Regulatory Asset of $198 million (nine months ended September 30, 2020 – $116 million).

[2] Pension and OPEB costs for the nine months ended September 30, 2021 exclude the net addition of costs of $37 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, 2020 − $54 million).

11. RISK MANAGEMENT AND DERIVATIVES

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

Interest Rates

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in interest rates. Interest rate risk for OPG arises with the need to refinance existing debt 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.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as debt issuances, fuels and certain materials and services purchased for generating stations and major development projects may be denominated in, or tied to, US dollars. To manage this risk, the Company employs various financial instruments such as forwards and other derivative contracts, in accordance with approved corporate risk management policies. Additionally, volatility in the Canadian/US foreign exchange rate also impacts OPG's financial results from certain of its subsidiaries, whose operations are based exclusively in the United States.

Commodity Prices

OPG is exposed to fluctuations in commodity prices. Changes in the market prices of nuclear fuels, oil, gas and biomass 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.

A number of OPG's hydroelectric facilities in the US sell energy and capacity into the wholesale electricity market and therefore are subject to volatility of wholesale electricity market pricing. While revenue from these facilities represents a small portion of OPG's overall revenue, the Company may enter into derivative instruments from time to time to further mitigate this risk.

Credit

The Company's credit risk exposure is primarily a function of its electricity and other sales. The majority of OPG's revenue is derived from electricity sales through the IESO administered market in Ontario. Market participants in the IESO 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 risk is considered acceptable due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts was $1 million as at September 30, 2021 and December 31, 2020.

The fair value of the derivative instruments totalled a net liability of $15 million as at September 30, 2021 (December 31, 2020 net liability − $14 million).

12. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the 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 current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

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 as at the 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. Various other fund investments are valued at the unit values supplied by the fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. 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.

OPG's financial instruments and their fair value as at September 30, 2021 and December 31, 2020 consist of the following:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2021**	**2020**	**2021**	**2020**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**19,666**	19,096	**19,666**	19,096	Nuclear fixed asset removal and nuclear waste management funds
Loan receivable – from Fair Hydro Trust	**937**	1,017	**911**	913	Loan receivable
Investment in equity securities	**229**	172	**229**	172	Equity securities
Payable related to cash flow hedges	**(10)**	(16)	**(10)**	(16)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(10,655)**	(11,160)	**(9,730)**	(9,332)	Long-term debt
Other financial instruments	**29**	30	**29**	30	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable, accrued charges and other payables 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 ONFA when the Nuclear Segregated Funds are in a surplus position.

The fair value of 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.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy:

As At *(millions of dollars)*	**September 30, 2021** Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**7,020**	**5,909**	**-**	**12,929**
Investments measured at NAV [1]				**2,532**
				15,461
Due to Province				**(4,308)**
Used Fuel Segregated Fund, net				**11,153**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,362**	**4,490**	**-**	**9,852**
Investments measured at NAV [1]				**2,018**
				11,870
Due to Province				**(3,357)**
Decommissioning Segregated Fund, net				**8,513**
Equity securities	**229**	**-**	**-**	**229**
Other financial assets	**15**	**-**	**40**	**55**
Liabilities				
Other financial liabilities	**(26)**	**-**	**-**	**(26)**

As At *(millions of dollars)*	**December 31, 2020** Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	6,660	5,780	-	12,440
Investments measured at NAV [1]				2,176
				14,616
Due to Province				(3,765)
Used Fuel Segregated Fund, net				10,851
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,144	4,315	-	9,459
Investments measured at NAV [1]				1,735
				11,194
Due to Province				(2,949)
Decommissioning Segregated Fund, net				8,245
Equity securities	172	-	-	172
Other financial assets	1	1	46	48
Liabilities				
Other financial liabilities	(18)	-	-	(18)

[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 second quarter of 2021, the Company transferred $19 million from Level 3 to Level 1. The transfer resulted from an investment that became publicly traded during the second quarter of 2021. The investment is valued using the active market price, which resulted in a pre-tax loss of $33 million and a pre-tax gain of $50 million being recognized in the interim consolidated statement of income for the three and nine month periods ended September 30, 2021, respectively.

The changes in the net assets measured at fair value that are classified as Level 3 financial instruments for the nine months ended September 30, 2021 were as follows:

(millions of dollars)	**Other Financial Instruments**
Opening balance, January 1, 2021	**46**
Transfers	**(19)**
Unrealized gains included in revenue	**13**
Realized losses included in revenue	**(5)**
Purchases	**5**
Closing balance, September 30, 2021	**40**

Investments Measured at Net Asset Value

Nuclear Segregated Funds

Nuclear Segregated Funds' investments classified as Level 3 consist of real estate, infrastructure, and agriculture investments within the alternative investment portfolio. The fair value of these investments is determined using financial information as provided by the general partners of the limited partnership funds in which the Nuclear Segregated Funds are invested. Direct investments are valued using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments 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.

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.

The classes of investments within the Nuclear Segregated Funds that are reported on the basis of Net Asset Value (NAV) as at September 30, 2021 were as follows:

(millions of dollars – except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Real Assets				
Infrastructure	**2,504**	**1,423**	**n/a**	**n/a**
Real Estate	**1,878**	**1,042**	**n/a**	**n/a**
Agriculture	**168**	**16**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**23**	**n/a**	**Daily**	**1-5 days**
Fixed Income	**2,176**	**n/a**	**Daily**	**1-5 days**
Equity	**992**	**n/a**	**Daily**	**1-5 days**
Total	**7,741**	**2,481**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture 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 these investments. The ownership interest in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their ownership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Cash distributions are received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds in this class will be liquidated.

Real Estate

This class includes investments in institutional-grade real estate property. The investment objective is to provide a stable level of income with an 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 investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their ownership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. Cash distributions are received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this class will be liquidated.

Agriculture

This class includes a diversified portfolio of global farmland 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 in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their ownership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Cash distributions are received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this class will be liquidated.

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, 2021, and December 31, 2020, 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. As at September 30, 2021, and December 31, 2020, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 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 as at September 30, 2021 and December 31, 2020 was 274.6 million. There were no dilutive securities during the three or nine month periods ended September 30, 2021 and for the year ended December 31, 2020.

15. COMMITMENTS AND CONTINGENCIES

Litigation

In 2006, OPG was served with a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice by British Energy Limited and British Energy International Holdings Limited (together, British Energy). The action claimed contribution and indemnity from OPG for any amounts British Energy was found liable for in an arbitration commenced against it by the purchasers of British Energy's interest in Bruce Power L.P. (the Claimants) regarding an alleged breach of British Energy's representations and warranties (the Arbitration). Both the action and the Arbitration related to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power L.P.

In 2012, the arbitrator found that British Energy was liable to the Claimants for some of the damages they claimed. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reflect that the Claimants 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". OPG defended the claim, and the parties exchanged documentary productions.

A pre-trial was held on May 31, 2021. Shortly thereafter, the parties reached a settlement of British Energy's claim and the action has now been dismissed. The settlement does not have a material impact on the Company's consolidated financial statements.

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 are 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 consolidated financial position.

Guarantees

As at September 30, 2021 and December 31, 2020, the total amount of guarantees provided by OPG was $4 million. As at September 30, 2021, the potential impact of the fair value of the outstanding guarantees to income is less than $1 million and OPG does not expect to make any payments associated with these guarantees.

Contractual Obligations

OPG's contractual obligations as at September 30, 2021 were as follows:

(millions of dollars)	**2021**[1]	**2022**	**2023**	**2024**	**2025**	**Thereafter**	**Total**
Fuel supply agreements	38	128	106	46	34	18	370
Contributions to the OPG registered pension plan [2]	46	193	-	-	-	-	239
Long-term debt repayment	62	179	44	607	578	8,287	9,757
Interest on long-term debt	86	356	348	337	322	4,941	6,390
Short-term debt repayment	115	-	-	-	-	-	115
Commitments related to Darlington Refurbishment project [3]	180	-	-	-	-	-	180
Operating licences	11	47	47	48	49	51	253
Operating lease obligations	-	10	7	6	4	20	47
Accounts payable and accrued charges	1,208	4	-	-	-	-	1,212
Other	61	64	63	63	15	99	365
Total	1,807	981	615	1,107	1,002	13,416	18,928

[1] Represents amounts for the remainder of the year.
[2] The pension contributions include ongoing funding requirements in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2020. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2023. 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 2022 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, 2021 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Contracted Gas Generation	Other	Elimination	Total
Revenue	957	-	370	168	193	2	-	1,690
Leasing revenue	6	-	-	-	-	6	-	12
Other revenue	1	52	-	-	-	25	(68)	10
Total revenue	964	52	370	168	193	33	(68)	1,712
Fuel expense	63	-	88	16	74	-	-	241
Gross margin	901	52	282	152	119	33	(68)	1,471
Operations, maintenance and administration expenses	400	52	87	56	13	15	(68)	555
Depreciation and amortization expenses	146	-	51	38	27	15	-	277
Accretion on fixed asset removal and nuclear waste management liabilities	-	271	-	2	-	1	-	274
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(243)	-	-	-	-	-	(243)
Property taxes	7	-	-	5	-	1	-	13
Income from investments subject to significant influence	-	-	-	2	-	-	-	2
Other losses	-	-	-	-	1	31	-	32
Income (loss) before interest and income taxes	348	(28)	144	49	78	(30)	-	561
Net interest expense								53
Income before income taxes								508
Income tax expense								78
Net income								430

Segment Income (Loss) For the Three Months Ended September 30, 2020 *(millions of dollars)*	**Regulated**			**Unregulated**				
	Nuclear Generation	**Nuclear Waste Management**	**Hydroelectric Generation**	**Contracted Hydroelectric and Other Generation**	**Contracted Gas Generation**	**Other**	**Elimination**	**Total**
Revenue	1,204	-	358	158	153	2	-	1,875
Leasing revenue	6	-	-	-	-	4	-	10
Other revenue	-	33	-	-	-	19	(48)	4
Total revenue	1,210	33	358	158	153	25	(48)	1,889
Fuel expense	78	-	90	14	43	-	-	225
Gross margin	1,132	33	268	144	110	25	(48)	1,664
Operations, maintenance and administration expenses	562	33	86	57	9	17	(48)	716
Depreciation and amortization expenses	207	-	53	36	28	13	-	337
Accretion on fixed asset removal and nuclear waste management liabilities	-	259	-	2	1	1	-	263
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(234)	-	-	-	-	-	(234)
Property taxes	7	-	-	4	1	-	-	12
Other gains	-	-	-	-	-	(7)	-	(7)
Income (loss) before interest and income taxes	356	(25)	129	45	71	1	-	577
Net interest expense								61
Income before income taxes								516
Income tax expense								126
Net income								390

Segment Income (Loss) For the Nine Months Ended September 30, 2021 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydroelectric Generation	Contracted Hydroelectric and Other Generation	Contracted Gas Generation	Other	Elimination	Total
Revenue	2,944	-	1,185	516	495	9	-	5,149
Leasing revenue	19	-	-	-	-	13	-	32
Other revenue	2	146	-	-	-	74	(196)	26
Total revenue	2,965	146	1,185	516	495	96	(196)	5,207
Fuel expense	192	-	244	39	153	-	-	628
Gross margin	2,773	146	941	477	342	96	(196)	4,579
Operations, maintenance and administration expenses	1,596	146	262	172	45	42	(196)	2,067
Depreciation and amortization expenses	436	-	157	112	82	45	-	832
Accretion on fixed asset removal and nuclear waste management liabilities	-	809	-	5	1	3	-	818
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(722)	-	-	-	-	-	(722)
Property taxes	20	-	1	13	1	2	-	37
Other losses (gains)	-	-	1	3	1	(92)	-	(87)
Income (loss) before interest and income taxes	721	(87)	520	172	212	96	-	1,634
Net interest expense								167
Income before income taxes								1,467
Income tax expense								220
Net income								1,247

Segment Income (Loss) For the Nine Months Ended September 30, 2020 *(millions of dollars)*	**Regulated** Nuclear Generation	**Regulated** Nuclear Waste Management	**Regulated** Hydroelectric Generation	**Unregulated** Contracted Hydroelectric and Other Generation	**Unregulated** Contracted Gas Generation	**Unregulated** Other	Elimination	Total
Revenue	3,473	-	1,166	496	270	4	-	5,409
Leasing revenue	19	-	-	-	-	12	-	31
Other revenue	-	102	-	-	-	60	(144)	18
Total revenue	3,492	102	1,166	496	270	76	(144)	5,458
Fuel expense	230	-	251	34	62	-	-	577
Gross margin	3,262	102	915	462	208	76	(144)	4,881
Operations, maintenance and administration expenses	1,697	102	232	167	25	29	(144)	2,108
Depreciation and amortization expenses	616	-	160	120	53	36	-	985
Accretion on fixed asset removal and nuclear waste management liabilities	-	781	-	5	1	4	-	791
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(693)	-	-	-	-	-	(693)
Property taxes	20	-	1	13	2	1	-	37
Income from investments subject to significant influence	-	-	-	(1)	(10)	-	-	(11)
Other gains	-	-	-	(3)	-	(13)	-	(16)
Income (loss) before interest and taxes	929	(88)	522	161	137	19	-	1,680
Net interest expense								190
Income before income taxes								1,490
Income tax expense								325
Net income								1,165

17. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

	Nine Months Ended September 30	
(millions of dollars)	**2021**	**2020**
Receivables from related parties	**(86)**	14
Fuel inventory	**(19)**	2
Materials and supplies	**14**	15
Prepaid expenses	**(47)**	(13)
Other current assets	**30**	3
Accounts payable, accrued charges and other payables	**170**	320
Net changes in non-cash working capital balances	**62**	341

18. ATURA POWER AND TC ENERGY SETTLEMENT AGREEMENT

In April 2020, OPG, under a wholly-owned subsidiary operating as Atura Power, acquired a portfolio of combined-cycle natural gas-fired plants in Ontario from TC Energy Corporation (TC Energy) for approximately $2.8 billion. The transaction was treated as an asset acquisition, as substantially all of the fair value of the assets acquired was concentrated within the plant assets. In connection with the closing of the acquisition, certain post-closing activities at the acquired Napanee GS were identified as an obligation of TC Energy, including remediation of certain plant asset components. The fair value of the property, plant and equipment acquired was recorded on OPG's consolidated balance sheet reflecting future operations of Napanee GS assuming successful remediation of the plant asset components.

Following a period of negotiations, in March 2021, Atura Power and TC Energy executed a settlement agreement for a reduction of $220 million to the purchase price consideration in exchange for the settlement of certain post-closing terms and conditions, including TC Energy's obligations in respect of post-closing activities at the Napanee GS. The proceeds received under the settlement agreement were recorded as a reduction to net assets in the first quarter of 2021, with no immediate income statement impact.